Guidehouse

Rule 21 Interconnection Program Evaluation

Prepared for:

California Public Utilities Commission

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List of Acronyms and Abbreviations

Acronym/ Abbreviation	Definition
AB	Assembly Bill
AHJ	Authority Having Jurisdiction
API	Application Programming Interface
BD	Business Days
CEO	Cost Envelope Option
CD	Calendar Days
CPUC or Commission	California Public Utilities Commission
DGS	Distribution Group Study
DIIS	Distribution Interconnection Information System
DS	Detailed Study
DSA	Detailed Study Agreement
EGI	Electric Generation Interconnection [team] (PG&E)
FERC	Federal Energy Regulatory Commission
FS	Facilities Study
GIA	Generator Interconnection Agreement
GIPT	Grid Interconnection Processing Tool (SCE)
IA	Interconnection Agreement
IDF	Interconnection Discussion Forum
IOU	Investor-Owned Utility
IR	Initial Review
ISP	Independent Study Process
kW	Kilowatt
MASH	Multifamily Affordable Solar Housing
MW	Megawatt
NEM	Net Energy Metering
NEM-A	NEM Aggregation
NEM-FC	NEM Fuel Cell
NEM CDCR	NEM for the California Department of Corrections and Rehabilitation
NGOM	Net Generation Output Meter
OIR	Order Instituting Rulemaking
PCI	PowerClerk Inc.
PG&E	Pacific Gas and Electric
PIDS	Pole Information Data System
PTO	Permission to Operate
PV	Photovoltaic
R.	Rulemaking

Acronym/ Abbreviation	Definition
RES-BCT	Renewable Energy Self-Generation Bill Credit Transfer
Rule 21	Electric Rule 21 Tariff
SASH	Single-family Affordable Solar Homes
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SIS	System Impact Study
SLD	Single-Line Diagram
SNEM	Standard Net Energy Metering
SR	Supplemental Review
WDAT	Wholesale Distribution Access Tariff
V-NEM	Virtual NEM

Executive Summary

Assembly Bill (AB) 2861 (Ting, 2016) authorizes the California Public Utilities Commission (CPUC or Commission) to conduct technical evaluations of utility practice in adherence to Rule 21 to understand current performance, successes, and challenges of the Investor Owned Utilities (IOUs – i.e., Pacific Gas and Electric (PG&E), San Diego Gas and Electric (SDG&E), and Southern California Edison (SCE)). The Commission retained Guidehouse Inc. to perform this data-driven assessment of utility practice in adhering to the Electric Rule 21 Tariff (Rule 21) requirements per AB 2861. The inaugural Rule 21 evaluation is also consistent with Senate Bill (SB) 1 (Murray, 2006), which directs regular assessment of the CPUC's jurisdictional proportion of the California Solar Initiative program. Guidehouse, under the oversight of the CPUC staff (collectively referred as the research team), and with stakeholder engagement, performed this evaluation from June 2019 through July 2020. This report presents the findings of the evaluation addressing administration of and adherence to Rule 21 requirements as carried out by the three IOUs in California.

This Rule 21 Interconnection Program Evaluation involved developing a questionnaire and data request, vetted by stakeholders at CPUC-hosted workshops, that targeted available utility data and bounded scope parameters. Based on the findings and recommendations of this evaluation, the CPUC may recommend or issue decisions that target programmatic enhancements. Primarily, the objectives of this evaluation of utility administration of the Rule 21 requirements address:

- Characterizing utility adherence to statutory requirements and Commission-approved decisions surrounding interconnection process timelines and applicable costs.
- Benchmarking utility interconnection practices and administrative operations.
- Identifying successful initiatives and mitigations from the IOUs to inform proposed policy or programmatic changes to Rule 21.

To achieve these objectives, the research team developed a research plan incorporating feedback from IOU and non-IOU stakeholders. The research team collected project specific quantitative data for a 3-year study period (July 2016 to June 2019) directly from each utility. The accessibility and availability of data was not consistent across the IOUs. When significant dataset gaps emerged, the research team developed samples to perform analysis. The quantitative analysis included detail on project types, technologies, sizes, project timelines, and costs. The analysis was supplemented with qualitative data gathered through interviews with the IOUs and developers. These interviews aimed to identify administrative constraints and opportunities for programmatic changes through Commission-approved decisions.

Using the data analysis results and stakeholder feedback, the research team develop key findings and recommendations, categorized by areas communicated by stakeholders as, 1) areas needing improvement in utility administration or applicable tariff, 2) areas where administrative implementation of Rule 21 could be more efficient, and 3) recommendations for future CPUC Energy Division led assessments to enable continuous improvement to Rule 21. The key recommendations are listed below followed by the key findings of the analysis.

1. **Data Tracking and Reporting:** Date tracking and reporting should be standardized for ease of reporting, transparency, and improved public accessibility. This would enable and enhance benchmarking and comparison efforts and may be feasible via existing informal forums or by way of regulatory action. Reporting should be consistent and streamlined to the greatest extent possible while also recognizing the distinct nature of some IOU processes.

2. **Project Population Characterization and Segmentation:**

    a) Detailed project or program type data should be provided for each project, and naming conventions for similar project types should be standardized where possible.

    b) At a minimum, data should be provided for both in-service and withdrawn projects.

    c) Explore size-weighted results rather than count-weighted results in future studies.

    d) Data for facility technology type(s) should be consistently reported to provide a comprehensive understanding of on-site technology combinations and storage configurations.

    e) Data should include fields that clearly indicate whether each Rule 21 review or study was performed. This will allow for identification of processes and timeline requirements by project.

3. **Rule 21 Timeline Performance**: Future data tracking and evaluation efforts should focus on particular steps or project types that exhibited weaker timeline performance, occurred relatively infrequently, and/or were not robustly assessed in this study due to limited data visibility. This includes projects sized greater than 100 kW, non-NEM projects, and steps for SR, SIS, FS, DGS, and upgrades.

4. **Study and Upgrade Costs:** For the purposes of continued CPUC-led evaluations, IOUs should better track associated cost expenditures for performed interconnection-related upgrades within project files and portfolios to expedite data collection activities and deliver more complete datasets in the future.

5. **Cost Certainty and Customer Impact:**

    f) IOUs have successfully used harmonized approaches to forecast triggered mitigations for applicants. However, improving precision of invoicing and applicable impact study results could help prevent excessive upgrades.

    g) Stakeholders desire more precise customer invoicing, billing component and true up education, and itemization of anticipated costs. Programmatic changes under the CPUC may expedite this process.

    h) Additional customer education is warranted to better represent the conditions where this effort is most effective in streamlining the interconnection process and providing cost certainty.

6. **Business Practices and Processes**

    i) All IOUs should improve upon customer educational efforts for small developers and individual customers and develop dynamic online portals for all types of projects.

    j) The CPUC should work with IOUs to develop and conduct customer service surveys and make Interconnection Discussion Forums (IDFs) and working groups more action oriented with implementation roadmaps.

k) The CPUC should spearhead an effort to develop an implementation roadmap to address the issues repeatedly raised at the IDFs and workshops.

l) Implement dynamic portal-based application processes for all process and project types and use portals to guide applicants to the correct application process, track project status, and provide notification of issues. Consider implementation of Application Programming Interfaces (APIs) with portals to save time and resources and standardize data collection to better align to the 77 applicable data fields discussed in detail throughout this report.

m) Limit frequency of changes or coordinate changes to the interconnection process to avoid confusion.

n) Balance overloaded utility representatives with cost-effective, prudent solutions, including third-party contractors, additional roles, seasonal responsibilities for influx periods, or other means of restructuring repositories to better record project details.

o) Improve existing stakeholder mechanisms (IDF, working groups) to move from discussion to action and encourage parallel avenues of refinement through prioritization of intermediate and long-term interconnection concerns.

The recommendations listed above are based on the key findings listed below:

1. Data Tracking and Reporting

The IOUs exhibited drastic differences in document formats, applicability of requested fields, and accessibility of tracked project-level interconnection data for the 77 fields requested, which made it difficult to comprehensively and rigorously assess utility adherence to Rule 21 requirements. PG&E provided a raw extract of its internal interconnection tracking database, which contained all project types with over 1,000 data fields. This required considerable effort to process. SCE and SDG&E provided spreadsheets for Net Energy Metering (NEM) and non-NEM projects with partial data fields. The data fields (e.g., program type, technology type, and project status) were inconsistent in format for each IOU, which made comparisons difficult. These inconsistencies stem from lack of standardization in utility processes, programs, or business practices, which were not stipulated in the Rule 21 requirements for the study period.[1] The datasets did not consistently indicate which of the study steps were applicable for any given project. Also, response to inquiry timelines, design and construction of interconnection facilities or upgrades timelines, commission inspection timelines and third-party timelines were not consistently tracked or available.

2. Project Population Characterization and Segmentation

The research team characterized and segmented the NEM and non-NEM project populations of each utility according to key characteristics such as program type (e.g., Standard NEM, Non-Export), project size, technology type, and the specific Rule 21 reviews or studies performed.

[1] See CPUC Decision 20-09-035, Section 5.1 (Issue 12: Improving Timeline Certainty) for additional information on future timeline reporting requirements.

p) Project or program type data detail varied across IOUs, including differences in program offerings and interconnection step nomenclature. PG&E and SDG&E NEM data differentiated between program types like Standard NEM, NEM-Aggregation (NEM-A), and Virtual-NEM (V-NEM) while SCE data differentiated only between NEM-1 and NEM-2. Each utility indicated detailed non-NEM project types, but naming conventions varied.

q) Some but not all datasets included project statuses other than in-service. The omission of non-in-service statuses limits this study. There are many other statuses for projects that are in progress. PG&E and SCE non-NEM data included all project statuses, while SCE NEM and SDG&E data included only in-service projects.

r) For all three utilities, larger projects (those greater than 100 kW) comprised an outsized proportion of aggregate capacity relative to their count, especially for NEM. Projects less than 30 kW accounted for between 97% and 99% of NEM projects by count for all three utilities. However, these projects accounted for a relatively smaller proportion of aggregate capacity—53% for PG&E, 63% for SCE, and 75% for SDG&E. The distribution of non-NEM project sizes skewed towards larger projects compared to the NEM populations. Projects less than 30 kW accounted for only 42% (PG&E), 20% (SCE), and 24% (SCE) of non-NEM projects by count and 0.2% (PG&E), 1.2% (SCE) and 1.2% (SDG&E) of aggregate capacity.

s) Project technology types were reported differently in the datasets, which complicated the identification of systems with multiple technology types. In the PG&E and SDG&E NEM datasets, storage appeared in the main technology type field, but it was not clear which were standalone or paired storage systems. In the SCE NEM dataset, the data included a separate field which flagged whether the project consisted of a storage system (all flagged projects appeared to be paired storage systems). Similarly, the PG&E and SDG&E non-NEM datasets listed storage in the main technology type field. The SCE non-NEM dataset included multiple technologies in the technology type field and their individual capacities when relevant, which allowed the research team to identify many unique technology combinations.

t) The specific Rule 21 reviews and studies performed were not clear for each project. The research team used other timeline-related data fields to determine what reviews or studies were performed and understand which timeline steps were applicable to each project. For PG&E, the reviews and studies performed could be clearly determined for around 98.5% of NEM and 75% of non-NEM projects. The SCE NEM dataset lacked fields for studies performed, but SCE’s non-NEM dataset included the reviews and studies performed for around 95% of records. For SDG&E, both the NEM projects and cleaned non-NEM projects datasets only required initial review.

3. Rule 21 Timeline Performance

Rule 21 specifies numerous specific steps and timeline requirements; however, the data request focused on key steps of the tariff to assess the project adherence to the timelines. The team analyzed the following:

- Key study steps, including application validation, initial review (IR), supplemental review (SR), system impact study (SIS), and generation interconnection agreement (GIA) execution.
  - Results were broken down into project subsets based on project size and technology type to identify differences or trends in performance.

- The total time from application submittal to Permission to Operate (PTO) to provide a holistic picture of the total time a project took to complete the interconnection process.

Overall, the timeline analysis showed that performance was best for projects or key tariff steps that were more common, routine, or even automated like small solar Standard NEM projects and steps for application validation and IR. Conversely, steps or projects that are less routine like SR and SIS, large projects, and non-NEM projects had mixed timeline performance. For many of these more infrequent steps or project types, the research team had limited data to evaluate.

a) **NEM Key Tariff Steps**: The key NEM timeline steps analyzed and the number of records analyzed in each step varied among the utilities depending on the available data and applicability to the project population. A number of steps for SCE and SDG&E were not analyzed due to lack of data; however, PG&E's data was comprehensive that allowed for analysis of all key steps. PG&E NEM timeline performance for the key steps analyzed ranged between 34% and 97%. The steps with the highest adherence rate were the expedited 30-day NEM provision, completing IR, and sending a draft GIA to the customer after completion of reviews or studies. The steps with the lowest adherence rate were responding to deficiency notifications, completing SR, and completing SIS after DSA execution. SR and SIS did not occur for most projects but were often delayed when they did occur.

b) **Non-NEM Key Tariff Steps**: The key non-NEM timeline steps analyzed were more consistent across the three utilities compared to the NEM timeline analysis because SCE and SDG&E provided more fields for non-NEM projects. The non-NEM datasets included far fewer projects than the NEM datasets for each utility, so the count of projects analyzed for each timeline step were relatively small.

    - Application deficiencies took additional time above the 10 business days specified in the tariff for PG&E and SCE.
    - PG&E timeline performance for other key steps ranged widely between 27% and 98%, with the steps for sending deficiency notifications and GIA execution had the highest adherence rates. The steps for completing IR and SR had the lowest adherence rates.
    - SCE non-NEM timeline performance for other key steps ranged between 43% and 100%. The steps for completing SIS and sending a draft GIA to the customer after completion of SIS had the highest adherence rates. The steps for completing IR and sending a draft GIA to the customer after completion of IR or SR had the lowest adherence rates.
    - For SDG&E, adherence to the 10 BD benchmark for application validation was higher than the other utilities, suggesting that application deficiencies are less common or more quickly resolved. Adherence rates for other key steps ranged between 39% and 97%. The step for sending a draft GIA to the customer after completion of IR or SR had the highest adherence rate while the step for the customer to execute the draft GIA had the lowest adherence rate.

c) **Timeline Performance by Project Size and Technology Type**: The team broke down results for each timeline step by project size and generation technology type to identify any trends in performance based on these characteristics. NEM projects of different sizes and technologies did exhibit statistically significant trends in timeline performance but non-NEM projects did not. In part, this was because the NEM project populations were much larger than the non-NEM populations and because the non-NEM populations were less skewed towards projects of any particular size or technology.

- For PG&E NEM, larger projects greater than 30 kW adhered to timeline requirements for a number of steps less frequently than smaller projects less than 30 kW. Similarly, non-solar projects tended to meet timeline requirements less than solar projects, though the analyses by technology type were limited by small sample sizes.
- For SCE NEM, adherence rates for larger projects were lower for many steps, but the small sample size of 10 projects greater than 30 kW did not allow for statistically significant conclusions about this trend.
- For SDG&E NEM, timeline adherence rates for larger projects were lower than smaller projects for the two steps analyzed, but this trend was less pronounced than what was observed for the other utilities. There was no statistically significant difference in the adherence rates for solar and non-solar projects.

d) **Total Time from Application Submittal to GIA or PTO**: Across all three utilities, the most common project types tended to complete the entire interconnection process from application to PTO quicker and within the required timelines more often that other projects.

4. Study and Upgrade Costs

The research team requested quantitative data on deposits, fees, and costs paid for studies and upgrades to assess cost-related provisions of Rule 21. The team identified the most cost-related data for PG&E, but fields for projects triggering upgrades and projects with estimated or actual costs were inconsistent. SCE and SDG&E, through sampling efforts, provided limited cost data.

- For PG&E, the data subsets for upgrades, estimated costs, and actual costs only partially overlapped, and most projects flagged as requiring upgrades did not have estimated or actual cost data.
    - Of the 768 projects (0.4% of all projects) marked as requiring upgrades, expanded NEM was the most common project type by count, but V-NEM, NEM-Fuel Cell (NEM-FC), and Renewable Energy Self-Generation Bill Credit Transfer (RES-BCT) triggered upgrades more frequently than the average rate of 0.4%. Larger projects were more likely to exceed existing system limits and hence require upgrades.
    - Estimated and actual cost data was present for only a handful of projects marked as requiring upgrades. Conversely, cost data was present for many projects not marked as requiring upgrades. For projects with both estimated and actual costs, estimates varied with examples of both under- and over-estimating actual costs.
- Cost data for SCE was limited, but the projects examined showed costs equal to the flat fees listed in the tariff.

- SDG&E provided data on customer SIS study costs paid, which was equal to the flat fee specified in the tariff. None of the in-service projects in the 3-year study period required distribution or transmission system upgrades.

5. Cost Certainty and Customer Impact

Cost-related information from discussions with utilities and developers informed the cost certainty related to estimated and actual interconnection costs and timelines. The utilities are positioned to make informed engineering decisions to modify their electrical facilities and assets as a result of engineering reviews, studies, and necessary screens, for safe and reliable operation of the system. While SNEM, non-export, and general fast track interconnection activities among IOUs are well administered, there are some areas of improvements.

- Costly distribution system upgrades are rare and, when identified, are often avoided through project redesign/downsizing or results meeting discussions on alternative mitigations. Typical upgrades and mitigations include system modifications made to transformers, reclosers, telemetry, service line extensions and access routes. Costs for upgrades vary depending on construction needs, with estimates ranging from the thousands to tens of thousands for smaller projects.
- Substation equipment upgrades are uncommon. Customers tend to avoid these costly upgrades by downsizing or redesigning their project. Upgrades often exceed the customer's facility's total cost-of-ownership.
- Discussions with developers highlighted some issued related to excessive or unnecessary upgrades identified by PG&E, though anticipate upgrade identification practices to improve over the next year due to upfront invoicing. At times, the original cost estimates changed after site inspections, and visits from the service planning department reveal differing results requiring scope modifications. Interviews suggest this is less common with SCE.
- Delays or scope/cost expansion of projects requiring distribution system upgrades in PG&E's service territory may indirectly impact customers awaiting PTO through loss of forecasted credit generation within the NEM programs. There is a requirement to maintain financial assurance, specifically noted with PG&E, through a security deposit in the form of a letter of credit and an escrow account. Continued deposits into these independent escrow accounts are required until disputes are resolved.
- Both external constraints and utility-identified mitigations drive material modifications to projects.
  - SCE's online portal allows for these changes to be processed rather than withdrawing and restarting the interconnection timeline; however, one developer noted significant deficiencies and delays caused by physical handoffs despite the portal's continued refinement of features.
  - Developers noted that PG&E is often willing to work directly with applicants on design adjustments, activities to prevent the need for withdrawal and re-application processes, and upgrade disputes. However, representatives are difficult to contact via email or phone. An average response window of three to five days causes frustration and unnecessary delays.
- During the construction phase, the timeline requirements attached to the cost methodology are limited; however, this phase is prone to frequent delays.

Engineering reviews and FS and SIS govern the necessary upgrades and these stages, including the design/construction phases, add to the uncertainty of interconnection cost estimates.

- Most developers do not find the Cost Envelope Option (CEO) to be an efficient offering as internal cost estimators and the utility Unit Cost Guides provide sufficient itemization to forecast anticipated expenses; however, agree that customer awareness of this option in practical use is lacking and requires additional public education. Only one to two projects were reported among the utilities to elect the CEO and reach PTO. Customers are often discouraged by the deposit amount. Smaller projects do not benefit from the CEO while larger projects are often facilitated by experienced developers and contractors.
- Feedback revealed that nascent developers and individual applicants may be at a greater disadvantage with less involvement navigating Rule 21 programmatic changes.

6. Business Practices and Processes

In addition to the specified tariff requirements, the business practices and processes determine the effectiveness of the Rule 21 Program implementation. The research team gathered anecdotal evidence from the IOUs and developers that can help improve administrative and operational practices to alleviate interconnection issues and disputes over time.

a) The tools and systems used by IOUs vary but are generally found to be user-friendly by the developers. However, the customer service experience, especially related to point-of-contacts for project follow-ups, varies.

- PG&E has tracking and coordination issues for interdepartmental communications when projects move from one team to another. Site inspections for projects under 10 kW are also often omitted or performed without practical notice for the customer. Assigned project representatives are often overloaded with various projects, which are increasing in complexity over time.
- SCE also has issues with coordination with field engineering teams. There exists a disconnect between interdepartment reporting, leading to reeducation of the project details from the applicant to the SCE representative who may be addressing specific elements of the tariff.
- SDG&E's direct interconnection team operates and responds to inquiries and follow-ups within a 24-hour window, on average, and experiences similar disconnects in relayed updates when moving the project along the interconnection track.

b) Application portals vary in functionality and usefulness, but developers find them all to be generally user-friendly and appreciate the continued improvements made over the last year and those anticipated for 2021.

c) Points of contact vary depending on project type and complexity for all three utilities

- Simple projects (generally Standard NEM) have shared inboxes or routing through general call centers providing no direct engagement outside of when an issue is raised.

- It often takes three to five days to reach a representative to discuss discrepancies or disputes, which is not satisfactory but is an expected outcome by project applicants.
- Non-standard NEM, non-NEM, large projects, or projects triggering upgrades generally have dedicated points of contact.

d) Handoffs between assigned project managers or utility departments and subsequent communication issues are common complaints for larger, non-NEM projects with PG&E and, to a lesser extent, SCE. SDG&E has been generally reported as providing adequate and timely customer service from the interconnection representatives.

e) Communication and customer service with regards to general inquiries to the interconnection process is similar to the timeline delays experienced with raising disputes.

- Utilities have different processes to responding to inquiries based on project type and/or size, but in general, it is much more challenging to reach a utility representative at PG&E versus SDG&E and SCE.
- Developers appreciate having dedicated managers, but experience problems with rotated assigned project managers, not receiving notification of a change in project managers, and inconsistent communication after handoffs.
- Developers spoke highly of communication from SDG&E. They expressed the most difficulties reaching out to resolve issues with PG&E.

f) Developers spoke to the usefulness of working groups and stakeholder sessions in spurring improvement over time and raising important issues for proactive discussion. Developers see room for improvement in turning the discussion and investigation reports into actionable initiatives or programmatic changes.

g) Favorable mention was given to the development of highlighted guides, example interconnection scenarios, frequently asked question (FAQ) documents that are routinely updated, tutorials, webinars, and wizard features to guide applicants throughout the process.

1. Background and Project Overview

Rule 21 outlines the set of rules governing the interconnection, operation, metering, and telemetry requirements for applicants wanting access to the IOU distribution grid through onsite generating facilities and storage devices. A series of regulatory directives, issued through CPUC formalized proceedings, have taken shape since Rule 21 was established in 1982. AB 2861 authorizes the CPUC to conduct technical evaluations[2] to understand current performance, successes, and challenges of the three large IOUs in adhering to the Electric Rule 21 Tariff (Rule 21).[3]

The CPUC's Energy Division retained Guidehouse Inc. (Guidehouse) to develop and execute this evaluation from May 2019 through July 2020 under oversight of assigned Energy Division staff .[4] The Rule 21 Interconnection Program Evaluation Project involved both quantitative data for the 3-year study period, and qualitative interviews with IOUs and developers to understand business processes and concerns.

The results of this evaluation, presented in detail in this Report, provide qualitative and quantitative assessments of Rule 21 Tariff activities carried out by the IOUs. These results reveal a baseline benchmarking of utility interconnection business practices and recommended procedural enhancements aimed at resolving disputes and concerns expressed by interconnection customers.

1.1 Electric Rule 21 Tariff

The Rule 21 Tariff is a set of regulations that describes the interconnection, operating, telemetry, and metering requirements for customers applying to connect generating and storage facilities at the distribution level of CPUC jurisdictional electric utility service areas. This collection of decisions, guidelines, and requirements allows customers to access the electric grid and receive benefits from renewable generation while utilities safely and reliably operate electrical assets. Each CPUC-regulated utility is responsible for administrating required elements of the Rule 21 Tariff through published utility-specific tariffs and hosted access to application portals. In September 2011, the CPUC opened Rulemaking (R.) 11-09-011 to review and establish necessary revisions to Rule 21 for a timely, nondiscriminatory, cost-effective, and transparent process for interconnection applications. Rule 21 includes the following provisions governing aspects of the interconnection process:

- Procedures and timelines for reviewing applications
- Fee schedules to process applications and perform impact studies
- Pro forma application and associated agreement forms
- Cost allocation of interconnection-related fees and upgrades

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[2] This evaluation is also an indirect response to the 2015 California State Auditor report entitled, *California's Alternative Energy and Efficiency Initiatives*, which directs the CPUC to act to ensure state policy goals are achieved.

[3] The IOUs studied in this evaluation include, in no order of importance, Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E). These utilities are collectively referenced as the IOUs throughout this report.

[4] The CPUC selected Navigant Consulting, Inc. (Navigant) to carry out this evaluation. Guidehouse acquired Navigant in October 2019, representing a corporate titleship change with no impact to the existing project team structure or work performed.

- Provisions specific to NEM generating facilities
- Technical operating parameters and certification for testing criteria
- Technical requirements for smart inverters
- Metering and monitoring requirements
- Procedures for informal and formal dispute resolution

In July 2017, the Commission opened the Order Instituting Rulemaking (OIR) to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21.[5] Each IOU administers the requirements of Rule 21 through individual versions of Rule 21 tariffs and business practices. The OIR includes principal topics to streamline and enable rapid adoption of distributed generation resources located on customer premises as well as mechanisms to assist capacity planning activities for forecasted growth. Additional considerations include incorporating IOU Integration Capacity Analysis[6] tools, using the cost envelope option[7] for applicants, and facilitating the transformation of utility business practice to more automated practices. Educational materials, additional documentation of concerns, and issues identified for future policy changes are captured in the quarterly IDF facilitated by the CPUC and the Rule 21 working groups and their resulting reports, which are also driven by R.17-07-007.[8]

1.2 Objectives and Evaluation Approach

The IOUs under CPUC jurisdiction have a Commission-approved Rule 21 interconnection tariff allowing customers and non-utility electric generators to connect generating facilities to the distribution grid. Because of expanded policies for the CSI program, the Self-Generation Incentive Program, and NEM, California has seen rapid adoption of customer-sited distributed generation. Such a high adoption rate necessitated a process to characterize utility compliance with statutory requirements, benchmark business practices, and generate a baseline. Based on the evaluation results, the CPUC may recommend or issue decisions that target programmatic enhancements. Primarily, the objectives of this evaluation of utility administration of the Rule 21 requirements address:

- Characterizing utility adherence to statutory requirements and Commission-approved decisions surrounding interconnection process timelines and applicable costs.
- Benchmarking utility interconnection practices and administrative operations.

[5] OIR 17-07-007 to streamline interconnection of distributed energy resources while making improvements to Rule 21.

[6] The Integration Capacity Analysis is also known as a hosting capacity analysis, which models and simulates accommodation of new DERs on the distribution grid prior to triggered upgrades for system reliability and safe delivery of electricity.

[7] The Cost Envelope Option allows non-NEM applicants an assured cost listing upfront related to the interconnecting facility or distribution upgrades. The option presents a banded 25 percent high/low bound based on the estimated and actual costs identified as maximum cost responsibility for the applicant.

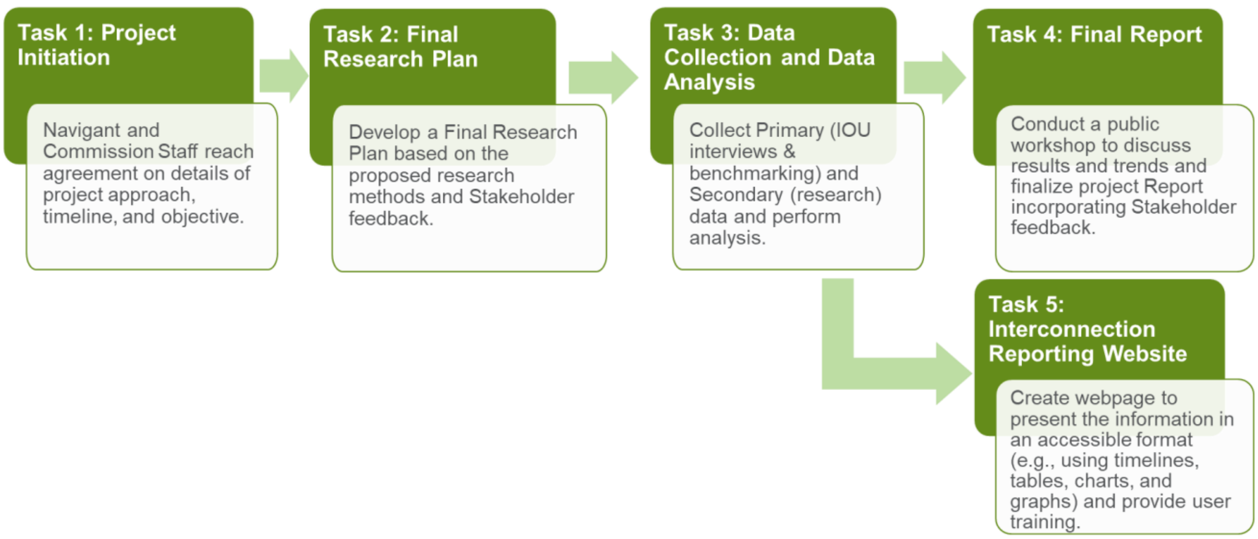
[8] This evaluation takes place outside of formalized, docketed proceedings or dispute resolution forums.

The Energy Division's IDF presents an informal avenue to relay a variety of issues, technical considerations, general interconnection practices, and policies to interested participants to foster constructive and effective communication and dispute resolution among stakeholders of the interconnection process. Resolution Administrative Law Judge-347 approved the IDF's establishment on October 12, 2017.

- Identifying successful initiatives and mitigations from the studied utilities that would allow proposal of policy or programmatic changes to Rule 21.

To achieve these objectives, the research team developed a research plan incorporating feedback from IOU and non-IOU stakeholders in agreement with the Commission. The evaluation approach considered the following steps or tasks shown in Figure 1.

Figure 1. Rule 21 Evaluation Approach



Discussion items and key topics were intentionally categorized to encourage a transparent informal interview surrounding utility leading practices, performance, and barriers experienced throughout the phases of the interconnection process. The data request was developed with stakeholder and utility feedback from late June 2019 through September 2019.

The final questionnaire developed for the evaluation's data collection stage resulted in the high-level topics listed in Figure 2.

Figure 2. Final Objective Details

Objective 1: Rule 21 Adherence

Utility Timelines
- Interconnection track delays and how they occur
- Timeline extensions and complex project track process
- Utility-missed milestones or gaps

Customer Timelines
- Delays from the customer and how those occur
- Frequently missed milestones from the applicant
- Guidance from the utility for applicants

Utility Cost Accounting
- Cost responsibility for system upgrades
- Planned versus unplanned upgrades and mitigations

Cost Envelope Option
- Drivers for projects coming over cost envelope
- Utility perspective on why it may not be fully utilized

Integration Capacity Analysis
- Utilization of Interconnection Capacity Analysis maps since 2018

Objective 2: IOU Comparison

Expected and Actual Timelines
- Utility timelines based upon fast track and detailed Studies
- Benchmark for design, construction, and commissioning timelines (and non-Rule 21 elements)

Utility and Project Cost (Estimated and Actual)
- Cost breakdown (utility and customer)
- Project cost margins and unanticipated upgrade comparison

Customer Service and Communication
- Response times and inquiry service between the utility and the applicant

Coordination between Departments / Offices
- Points of contact and queued project responsibilities
- Service territory and decentralized office impact to coordination

Recordkeeping
- Handling customer information
- Interconnection data utilization to mitigate issues

Workload Planning
- Budgets allocated to administration and staff
- Resource planning for potential interconnection growth

The research team developed the questionnaire and data request incorporated historical references from the interconnection proceedings and working group findings. The CPUC has also fostered avenues to communicate disputes and administrative hurdles among developers, IOUs, and interested interconnecting applicants through formal processes and quarterly engagements under the IDFs. Through these avenues, the CPUC's goal is to provide stakeholders a venue for proactive interconnection resolution discussion and constructive dialogue regarding issues related to Rule 21 implementation and the technical requirements of the tariff. The IDF Charter states that the forum provides an "informal venue for stakeholders to explore a wide variety of issues related to interconnection practices and policies and will exist independently of any concurrent proceeding on interconnection." Guidehouse reviewed and participated in the IDF quarterly meetings throughout the evaluation timeline to better understand grievances and disputes communicated by interested parties.

Per Section K of Rule 21, IOUs must appoint a designated ombudsman to address disputes regarding Rule 21 missed timelines or delays. AB 2861 intended to address the inadequacy of this process. Table 1 provides a list of Rule 21 Ombudsman for each IOU.

Table 1. IOU Rule 21 Ombudsman List

Pacific Gas and Electric (PG&E)	Southern California Edison (SCE)	San Diego Gas & Electric (SDG&E)
rule21.ombudsman@pge.com 916.203.6459	Rule21.Ombudsman@sce.com 714.895.0211	rule21.ombudsman@semprautilities.com 858.637.7986

On October 12, 2017, the Commission approved Resolution ALJ-347, which established an expedited process to resolve interconnection disputes between applicants, developers, and utilities. The expedited process will take 45-60 business days to receive an Executive Director Order directed to the utility and applicant. The formal dispute process aims to create a mechanism to elevate and resolve interconnection concerns. Throughout the engagement, stakeholders lauded the effort to establish this process and but also have concerns regarding the execution. As this process is designed to rely greatly on outside mediation, customers will likely need to record informal attempts to resolve disputes with the IOU prior to triggering this formalized process. Additional concerns surround the level of technical expertise to present the case for many engineering determinations and system upgrade cost allocations—all of which may cause additional delays and cascading effects to the process timeline.

1.2.1 CPUC-Hosted Workshops

The research team facilitated two stakeholder workshops: the initial reveal of the research plan and a concluding engagement to present draft results of the evaluation. On June 27, 2019, CPUC and Guidehouse facilitated the initial workshop to discuss parameters of the study areas and approach to developing and executing the research plan. Workshop attendees included developers, coalitions, and IOU interconnection personnel. Guidehouse presented an update to stakeholders on September 11, 2019. The stakeholder update provided an overview of the survey information sent by the evaluated utilities. Guidehouse also presented an update to the modifications made to the questionnaire and data request form after assessing stakeholder feedback.

The public workshops were an additional venue for stakeholders to provide feedback and experience in navigating the dispute resolution process and lessons learned from anecdotal projects. While both administrative practice and technical considerations of Rule 21 contribute to the complaints communicated through dispute resolutions, the research team narrowed the scope to administrative implementation and activities aligning to utility business practices. The workshops also served as the primary venue for all stakeholders to openly discuss ongoing concerns. These contributions provided the research team insight into achievable key study components. The research team presented the preliminary evaluation findings of the data extraction and assessment phase at the public workshop on August 13, 2020.

1.2.2 Primary and Secondary Source Interviews

Primary interviews with the IOUs allowed Guidehouse to contextualize findings based on general sentiments from the different track and phase stages, milestones, and administrative needs of the interconnection process. The IOUs shared this information through project examples, the evolution of internal procedures, and clarification of milestone and conflict resolution activities perceived as both challenges and successes. Interviews were conducted in an informal setting, leaning on the primary topics of the final research plan.

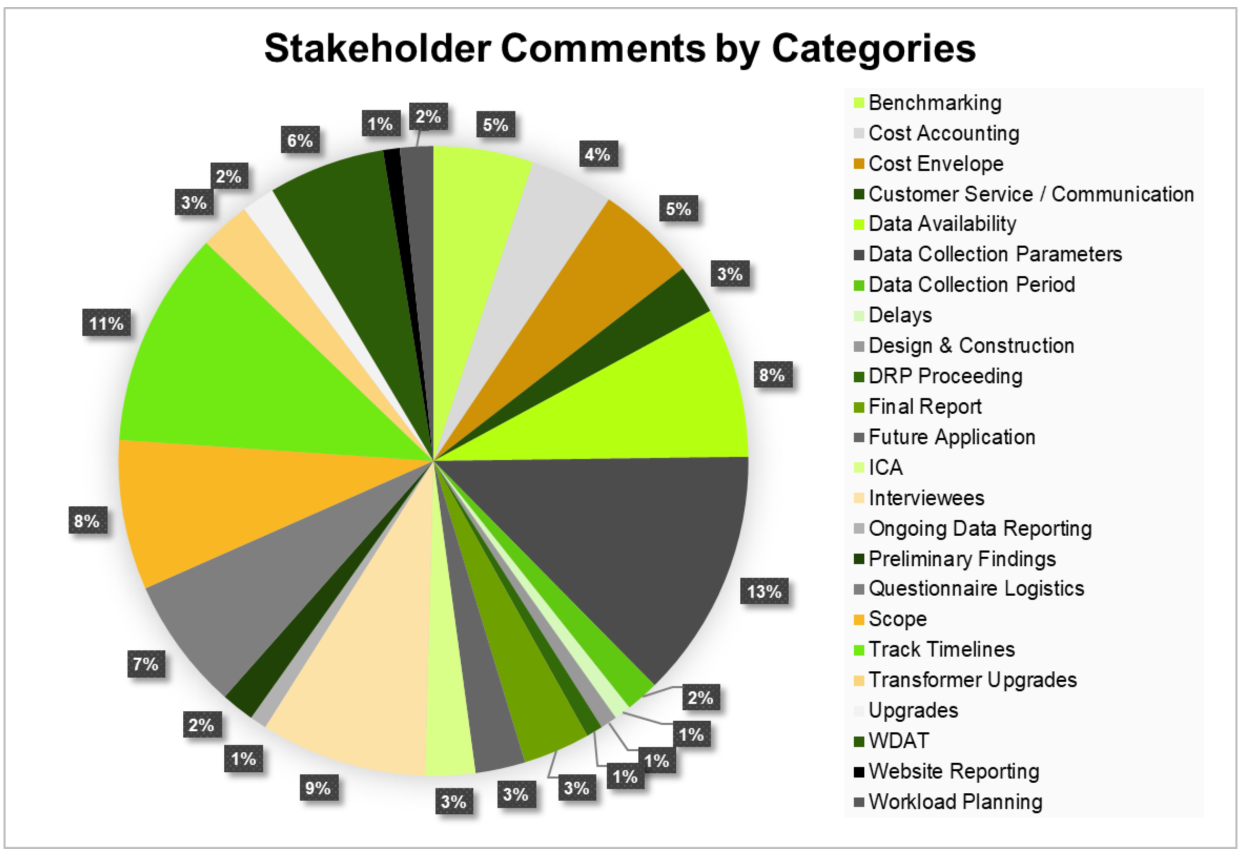
Secondary information supplemented the empirical analysis results and IOU interviews through discussions with nine developers after concluding Task 3 of the research plan. Further details are presented in Section 2.2 and Section 6 of this report. Following a similar format mapped for the primary interviews, the research team conducted nine interviews with California developers and contractors privy to the policy and implementation concerns relative to Rule 21 and experienced in the interconnection process across the state. The team anonymized the interview results to maintain confidentiality and allow transparent representation of anecdotal disputes or concerns. These findings contributed to the recommendations presented in Section 7 of this report.

1.2.3 Study Scope Modifications

Guidehouse presented its approach for the Rule 21 Tariff Program Evaluation to the CPUC Energy Division in May 2019, leading to a public introduction of the scope of work a month later. The research plan underwent several refinements as a result of discussions with the CPUC and comments received from an initial workshop on June 27, 2019. The workshop facilitated open stakeholder discussion surrounding interconnection characteristics of interest and parameters of scoped data requested for analysis. The IOUs opined that the scope should be narrowed and limited to distribution-level interconnecting projects subject to the CPUC's jurisdiction. Because non-NEM Export generating facilities transitioning to the wholesale distribution access tariff (WDAT) are subject to the Federal Energy Regulatory Commission (FERC) jurisdiction, they were considered out of scope for this analysis. Similarly, projects in the interconnection queue that have been withdrawn were also eliminated from this study. These recommendations were included in the final research plan. The data received was divided into two study groups for NEM and non-NEM projects.

The stakeholder comments categorized by topic of investigation under the evaluation are illustrated in Figure 3.

Figure 3. Stakeholder Feedback by Category



Throughout the feedback period, the research team collected comments from verbal communication documented at the initial workshop, direct engagements, and clarifying meetings. Participants communicated a need to understand the parameters set for data collection and provided detailed interview question modifications on the operational practices to administer the interconnection phases and their respective milestones. Figure 4 lists the suggested revisions as well as additional discovery fields contributing to the data request per Objective 2 of the research plan. The green highlighted fields indicate complete use or confirm existing headings within the data request template; yellow items recognize elemental or partial use of the recommended items as part of the revision process.

The research team tried to reduce the burden of data discovery and collection for IOUs by striking request items that:

- Reveal privacy detail or critical infrastructure as stipulated by North American Electric Reliability Corporation standards
- Include location-specific details such as meter number or impacted substation
- Represent withdrawals or projects moving into WDAT
- List compiled engineering study findings and optional results meeting dates
- Contain information that could otherwise be inferred by complementary request headings (e.g., required milestones, costs incurred at certain stages of the interconnection phase, total time between steps that can be manipulated through submitted dates)

Figure 4. Stakeholder Feedback Used (Detail)

1) Application Received (Date and Time)	19) Date cost estimate provided (if applicable)
2) Queue Number	20) Date Cost Envelope Deposit Submitted (if applicable)
3) Procurement Program (if known)	21) Date Cost Envelope Estimate Provided (if applicable)
4) Current Interconnection Request Status	22) Electrical Independence Test Results
5) Customer Requested COD (from application)	23) Distribution Group Study Participant?
6) Updated Commercial Operation Date	24) Date System Impact Study / Phase 1 Provided To Applicant
7) Facility County	25) Date Facilities Study / Phase 2 Provided To Applicant
8) Substation	26) Date Customer Requests Modification (if applicable)
9) Generation Type (i.e. solar, storage, wind, solar+storage)	27) Date Material Modification Determination is Made (if applicable)
10) Summer Max Capacity (MW)	28) Date Interconnection Agreement Provided to Applicant
11) Max Export Amount	29) Date Applicant Returns Signed Interconnection Agreement
12) Export status (non-export, limited export, or full export)	30) Date Line Side Tap Variance is Complete
13) Date Receipt of Application Acknowledgement Sent	31) Date NGOM meter is installed
14) Date Interconnection Request Deemed Complete (notes field should be used to indicate if applicant has to submit additional information one or two times to complete application)	32) Date of Receipt of Final Customer Payment of Invoice and Construction
15) Date Initial Review Provided to Applicant	33) Types of Upgrades Necessary (developed consistent categories)
16) Initial Review Results (and Screens Failed if applicable) (how to incorporate ICA into Rule 21, may be appropriate to add additional fields to track whether projects were proposed within the ICA (Op Flex or Static Grid) and the corresponding Supplemental Review analysis.)	34) Estimated construction costs 35) Final construction costs 36) Date Upgrade Construction is Complete
17) Date Supplemental Review Provided To Applicant	37) Date of Scheduling Test
18) Supplemental Review Results (and Screens Failed if applicable)	38) Date Customer notifies the utility it is ready for PTO

(light orange)	Partial use of recommendation
(green)	Complete use of recommendation **or** confirming existing data point is already captured in the data request

The first revisions applied to the questionnaire and data request items. The research team eliminated closed-ended questions, clarified specific elements pertaining to the conversation topics, and revised the template for collecting interview responses. Over several weeks, the research team aggregated comments into a feedback template form, redlined the range of recommended revisions for stakeholder presentation, and provided informal responses from the CPUC through issued documentation detailing the rationale for incorporated items. Table 2 shows the results presented to stakeholders.

Table 2. Summary of Changes to Data Collection

Questionnaire Changes	
Objective 1: Questionnaire	
1	Revised any closed-ended question to enable conversational discussion/detailed response
2	Added two timeline questions related to fast track and detailed study track durations
3	Eliminated redundant missed milestone question
4	Updated cost envelope question (non-substantial)
5	Added cost envelope question: perspective of utility on the lack of utilization

6	Changed customer/developer communication question from closed-ended to open and targeted
7	Removed (now) unnecessary Yes/No columns
8	Changed general format for efficiency during the interview process
9	Added cost envelope question: usefulness in the future perspective
10	Removed developer-specific question
11	Included business procedures questions relating to Standard NEM
12	Incorporated Interstate Renewable Energy Council's (IREC's) suggested question on how the utility handles/tracks interconnection delays
13	Revised line 17 question to understand customer application deficiencies
14	Included question about external process delays caused by outside factors/entities
15	Included question on missed payments by customer
16	Included two verifying questions on customer delays and complete application conditions
Questionnaire and Data Request Changes	
Objective 2: Questionnaire	
1	Revised using similar format as Objective 1 tab
2	Removed developer-specific question
3	Included clarifying question to understand average response times to customer inquiries/disputes
4	Incorporated IREC's suggested question on how the utility handles supplemental review delays and which stage in the process they often occur
5	Incorporated question on how the utility handles system impact study delays and how often occur
6	Incorporated question on how the utility handles facilities impact study delays and how often occur
7	Revised question to request average time to notify the customer for related review results and payment
Data Request	
1	Translated matrix for row item entry for easier data collection
2	Included data request items related to each interconnection application
3	Updated questions related to the estimated and actual costs (some should be under actual)
4	Replaced utility fees with incurred costs for additional clarity
5	Included attribute fields for WDAT/incomplete applications and those requiring Rule 2, 15, or 16 applications
6	Included attribute fields: holds put on application process, additional reviews, technical screen results
7	Included attribute fields: timeline date requests for phases and milestones within the interconnection process
8	Included additional attributes based on comments and suggested parameters

1.2.3.1 Second Revision to Data Collection Materials

Follow-up changes to the questionnaire and data request templates addressed clarity and usefulness of the inquired information. The research team provided comment flags to the headings of the data fields and a data dictionary to better align utility definitions of specific elements relative to Rule 21 governing conditions. While several issues were addressed in the first revision, areas stating *list multiple* required further discussion to present the requested information. The team attempted to relieve the onus for the IOUs to manipulate data by incorporating date fields for project milestones, framing an interval that was converted to a time interval during the data cleaning stage.

Flat and fixed fee/cost fields, which require parsing through paper documentation, were also removed from the data request to minimize the utility-responsible data collection process. For areas where defined costs and fees are presented in Rule 21, the research team developed a script to align associated costs with interconnecting project types, unless other cost data is otherwise provided separately. Routine calls between the research team and IOUs also confirmed accuracy of the materials provided. The IOUs communicated concerns about whether the delivery and application of this information into a three-dimensional model would reveal meaningful results. The data sampling and cleaning stage of Task 3 focused on extracting significant values such that a standardized data baseline could be achieved during the results stage.

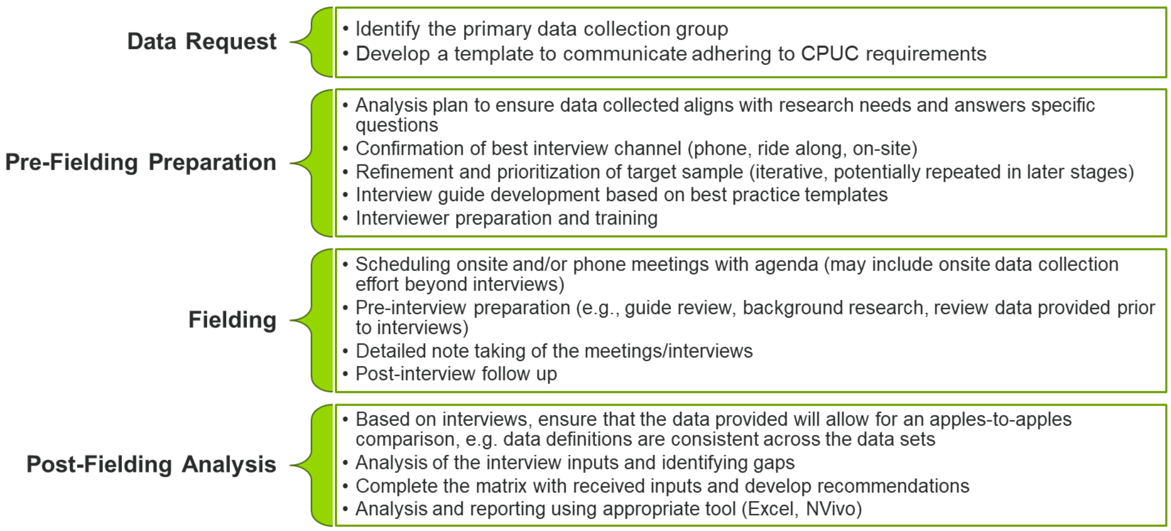
The early version of the research plan targeted a benchmarking step across a selection of states and identified utilities. This process would require a secondary analysis comparing administrative practices among utilities across the country. While this effort suggests that additional findings and enhancements could be extrapolated from existing procedures from other regulatory agencies, stakeholders and the Commission agreed that the approach would lengthen the evaluation and require a similar data requests to out-of-state utilities willing to participate. This aspect of the evaluation may be reconsidered in a follow-up or update to this assessment. Instead, the research team opted to consider feedback from the stakeholder group, which resulted in similar qualitative interviews with developers experienced in navigating the interconnection requirements within the respective utility jurisdictions.

Maintaining the problem statement categories identified in the scope of work, stakeholders and the research team vetted known interconnection grievances reported by applicants and developers within regulatory proceedings, dispute resolution forums, and the quarterly IDFs. The team applied stakeholder feedback, which resulted in two revisions of the data request and questionnaire form; these revisions were shared for comments in September 2019 and October 2019, respectively. The research team held final discussions with the respondents and aimed for Task 3 execution over the subsequent months.

2. Evaluation Methodology

This section describes the methodology used for data collection and analysis. Collection activities included a quantitative data request of interconnection project data from each utility (Section 2.1) and qualitative primary source interviews with utility interconnection personnel. The research team supplemented these findings using secondary source interviews with project developers with sizable developments in the state (discussed in Section 2.2). Section 2.3 describes the procedures and assumptions the team used to analyze the quantitative data and assess IOU adherence to administrating Rule 21. Figure 5 outlines the Task 3 approach.

Figure 5. Study Approach



2.1 Quantitative Data Request

After issuing the final research plan, the research team and CPUC developed a quantitative data request to collect the data identified under the study's scope. The data request template consisted of 77 fields across five topic areas, as Table 3 summarizes. Appendix A presents the complete list of fields in the data request.

Table 3. Summary of Data Request Topics

Topic Area	Number of Fields	Description
Project Information	25	Basic project details
Timeline Fields	15	Time for review and study phases like initial review (IR), supplemental review (SR), etc.
Estimated Costs	8	Estimated study and upgrade costs
Customer Actual Costs	24	Actual study and upgrade costs paid by applicant
Utility Actual Costs	5	Actual study and upgrade costs incurred by utility

Informational engagement meetings were held with the IOUs to discuss the expectations the data collection step. On August 20, 2019, the research team compiled responses from the IOUs surrounding the availability and accessibility of each data request field given the timeframe for collection and assessment. For each data field, IOUs indicated whether the requested data was:

A. Readily accessible (i.e., the data is tracked and could be easily produced for each applicable project in a database format)
B. Available but not readily accessible (e.g., required manual data collection)
C. Not currently tracked or documented, or not applicable

Figure 6 summarizes each IOU's categorization of the data request fields.[9]

Figure 6. Summary of Available Interconnection Data Surveyed

SUMMARY BY UTILITY

CATEGORY	A	A/B	B	B/C	C	NA	OTHER
PG&E	24	6	37	6	0	3	1
SCE	23	0	15	0	38	1	0
SDG&E (NEM)	10	0	61	0	5	1	0
SDG&E (Non-NEM)	7	0	65	0	5	0	0
TOTAL	**64**	**6**	**178**	**6**	**48**	**5**	**1**

The data field summary revealed that the fields readily available and the fields requiring manual data collection varied among the IOUs. A majority of fields for each utility were categorized as B (available but not readily accessible) or C (not tracked or documented). Conditional responses indicate an onerous process to pull that requested data item for all project types. Table 4 summarizes the utilities' categorization of the data fields by data request topic area. Alignment across all three IOUs illustrated that they did not track administrative or miscellaneous costs associated with the interconnection process or information related to outside entity-related delays on an individual project basis.

Table 4. Overlap of Data Fields Not Tracked

Data Request Category	A	B	C	C/documented	Conditional	N/A
Customer Costs (Actual Costs)	7	30	10	-	2	2
Interconnecting Project	38	24	2	4	9	2
Timelines	7	26	8	-	3	1
Estimated Costs	-	14	8	-	2	-
Actual Costs	-	9	4	-	2	-

The greatest overlap for readily accessible information was the interconnecting project category. The research team conducted discussions with each IOU to understand the data collection and tracking processes among the utilities, which is summarized in the following bullets.

- SDG&E maintains project data within individual application files and informational exchanges between utility representatives for much of the interconnection application process. The desired information requested is primarily housed in .pdf documents, email

[9] SDG&E provided responses separated for NEM and non-NEM project data records, as shown in Figure 6.

files, and digital folders. The logistical needs to present this data would stress utility personnel in order to maintain typical business responsibilities.

- PG&E noted that manual data collection procedures would be required to produce many available but not readily accessible fields, while a majority of fields stored in database format were readily available.
- SCE had the least amount of readily accessible information and indicated that non-tracked fields such as actual project costs were kept in a different format (e.g., work orders and other department classifications) rather than a central data repository.

2.1.1 Data Received

The research team received data for a varying number of the requested fields from each utility, which was expected given the availability and accessibility (A/B/C) responses noted in the previous section. The data also varied considerably in format, file structure, and comprehensiveness.

The data request was sent as a tabular spreadsheet file with the requested data fields comprising the columns of the table. The research team's expectation was that each utility would populate the table with row entries for each project. However, the data received varied considerably in both format and comprehensiveness, as Table 5 summarizes.

Table 5. Summary of Data Structure and Fields Received

Utility and NEM Type	No. of Files	No. of Fields	Notes
PG&E (Combined)	203	1,024	Database extract reconstructed to identify requested data fields. Additional sampling not performed.
SCE NEM	1	10	Additional sampling performed for 45 fields.
SCE Non-NEM	2	35	Additional sampling performed for 25 fields.
SDG&E NEM	1	11	Additional sampling performed for 1 field.
SDG&E Non-NEM	1	25	Additional sampling performed for 3 fields.

PG&E provided its data in a unique format that required substantial effort from the research team to process and analyze; however, it was considerably more comprehensive in terms of the number of fields and granularity of information provided. Specifically, PG&E provided a raw extract of its internal interconnection tracking database for the evaluated 3-year time period. This extract consisted of over 200 separate spreadsheet files, which reflected data present in a relational database with over 1,000 unique fields. The research team analyzed each provided field and partially reconstructed the database to create tabular data files that were similar to the original data request. Because of the comprehensiveness of this extract, the team was able to identify the majority of the fields in the data request.

SCE and SDG&E provided the data in tabular formats similar to the data request file, each with one table for NEM records and another for non-NEM records. However, these tables varied in the number of fields provided out of the 77 requested depending on differences in each field's availability, accessibility, and relevance. Appendix B provides a complete listing of the specific data fields received from each data response, while the following bullets present a condensed summary.

- The SCE NEM data file consisted of 10 populated data fields for in-service projects only. These fields related to basic project details such as project type, size, technology, and program type. Only one timeline field—project PTO date—was provided. Other key fields such as the date of application submittal, date application deemed complete, dates of reviews and studies, and all cost-related fields were missing. The research team pursued additional sampling for a number of these key fields.
- The SCE non-NEM data file was more complete than the NEM data and contained 35 populated data fields for all project statuses (e.g., in-service, withdrawn, in progress). The 35 fields included basic project information and a vast majority of the relevant timeline fields requested. The main missing fields were those related to study costs and upgrade costs. The research team sampled for a number of these fields.
- The SDG&E NEM data file contained 11 populated data fields for in-service projects only. The fields covered basic project details and timeline fields related to application, initial review (IR), generator interconnection agreement (GIA) execution, authority having jurisdiction (AHJ) inspection, and PTO. These timeline fields were sufficient to conduct the timeline analysis related to the expedited 30-day NEM provision discussed in Section 2.3.2.2. SDG&E staff indicated that most of the other excluded fields from the original request of 77 fields were not applicable to any project. For example, no projects required supplemental review (SR), system impact study (SIS), or system upgrades, so the fields related to these aspects were not applicable to any project. The research team pursued additional sampling for one field related to qualitative issues that arose during the interconnection process.
- The SDG&E non-NEM data file contained 25 populated data fields. The fields covered basic project details and timeline data for all relevant reviews and studies. SDG&E staff indicated that most of the other excluded fields from the original request of 77 fields—such as those related to upgrade costs—were not applicable to any project. The research team pursued additional sampling for three fields: two related to the SIS-related costs for the two projects that underwent SIS, and one related to qualitative issues that arose during the interconnection process.

The research team sampled a selection of SCE and SDG&E projects to obtain data necessary to complete the study that was not included in the initial data set provided by each utility. Section 2.1.2 describes the sampling methodology, and Appendix B lists the specific fields requested in the sampling effort.

The difference in the data file structures and fields received illustrates the challenges the research team faced in collecting thorough, consistent, and accessible data on interconnecting projects from each utility. On one end of the spectrum, PG&E was able to provide comprehensive and transparent timeline data, but in a format unsustainable for ongoing evaluation efforts because of its cumbersome structure and the substantial effort required to reconstruct and analyze the desired fields. On the other end, SCE and SDG&E provided data in an easy-to-handle tabular database format but only provided a portion of the information requested to monitor performance against the rules in Rule 21. In many cases, this lack of data was because fields were not applicable to any project, but in others, it was because the data was not readily available for all relevant projects, which required additional sampling efforts.

To streamline future studies and promote the regular collection of robust data, the Commission should ensure utilities track the key fields needed to assess timeline and cost performance in an accessible format that can be readily produced and regularly reported. This would prevent the need for additional sampling or multiple rounds of data collection while balancing the effort required to process and manipulate the data files received.

2.1.2 Additional Data Sampling

The research team sampled a set of SCE and SDG&E projects to obtain additional data for key fields missing in the initial NEM and non-NEM data responses. The team worked with utility staff to identify the source and level of effort required to collect data for each missing field. The team also discussed the nature of the project populations with each utility to determine which fields did not need to be collected. For example, if no projects underwent a facilities study (FS) during the study period, then the fields related to Date of FS were not requested in the follow-up sample.

To balance the need for additional data with the level of effort required for additional manual data collection, the research team analyzed the missing fields from each data file and selected a subset of the fields to prioritize for the sample request. Table 6 summarizes the sampling methodology used for each dataset including the basis of stratification, the sample size, and the number of fields requested. Additional detail on sample stratification and the number of sampled projects is provided later in this section.

Table 6. Overview of Project Sampling

Utility	NEM Type	Population Size	Stratification Basis	Sample Size	Fields Sampled
SCE	NEM	134,838	Project size (kW)	85	45
SCE	Non-NEM	1,028	Process track (e.g., fast track, independent study process [ISP])	85	24
SDG&E	NEM	71,303	Time from application to PTO	125	N/A
SDG&E	Non-NEM	133	Time from application to PTO	46	2

The research team sampled fewer fields from SDG&E than SCE, because some missing fields from the original request were not applicable to any project. Specifically, the team confirmed with SDG&E interconnection staff that no completed projects underwent SR, FS, or distribution group study (DGS) during the study period. Additionally, no projects required system upgrades. Therefore, for NEM projects, the sampling only involved collecting a qualitative list of project issues from SDG&E's internal project tracking system. For non-NEM projects, the sample request included two additional fields related to SIS costs, which were applicable to only two projects.

The number of sampling fields requested from SCE, and in particular SCE NEM, was much larger because key timeline and cost data were absent from the initial data files. The research team requested 45 additional fields for SCE NEM projects and 25 additional fields for SCE non-NEM projects. For the NEM population, the sampled fields were needed to conduct all timeline assessments because the only timeline field included in the initial data file was the project PTO data. For the non-NEM population, the sample population was used to assess the study and upgrade cost frequency and the timeline steps related to SIS and FS. Appendix B provides the full list of fields that were sampled from both SCE and SDG&E.

Prior to drawing samples of projects, the research team defined strata in the project populations to make sure the sample would provide visibility into larger projects, projects that underwent more complicated reviews or studies like SR and SIS, and projects that experienced delays. The team stratified this way to ensure the sample would include any larger projects or projects that underwent any review or study beyond IR given the dominance of small projects.

The stratification method varied depending on the data available in the initial data files received for each utility and NEM type. For SCE NEM, data on the reviews or studies performed for each project, the process track, and the total time from application to PTO were all unavailable in the initial data. Based on discussions with SCE staff, the research team used project size as a proxy for project complexity and sampled using the strata listed in Table 7.

Table 7. SCE NEM Sampling Strata

SCE NEM Stratum	Population Size (Count)	Statistical Sample Size
Less than 10 kW	122,994	66
10 kW-29 kW	10,079	9
30 kW-999 kW	1,737	5
1 MW or greater	28	5
Total	**134,838**	**85**

For SCE non-NEM, the initial data file included data on the process track of each record. As a result, the research team was able to stratify accordingly, as shown in Table 8.

Table 8. SCE Non-NEM Sampling Strata

SCE Non-NEM Stratum	Population Size (Count)	Statistical Sample Size
Fast track	842	59
Non-export	118	10
Detailed study	60	9
Other	18	7
Total	**1,038**	**85**

The initial data files from SDG&E for both the NEM and non-NEM populations contained the application date and PTO date fields for every project. The research team used these two fields to calculate the total time from application to PTO for each project in business days (BD) and used this to stratify the populations, as shown in Table 9 and Table 10. This approach ensured the sampled information on project deficiencies and issues would include projects that faced delays in the interconnection process.

Table 9. SDG&E NEM Sampling Strata

SDG&E NEM Stratum	Population Size (Count)	Statistical Sample Size
30 BD or less	65,028	40
31-60 BD	3,904	20
61-120 BD	1,671	15
121-240 BD	550	40
241 BD or greater	150	10
Total	**71,303**	**125**

Table 10. SDG&E Non-NEM Sampling Strata

SDG&E Non-NEM Stratum	Population Size (Count)	Statistical Sample Size
60 BD or less	14	7
61-180 BD	85	11
181-240 BD	21	17
241 BD or greater	13	10
Total	**133**	**45**

After stratifying the project population for each utility, the research team used statistical techniques to calculate the number of projects necessary to determine the proportion of projects that met the Full Max total time from application to GIA or PTO requirement as described in Section 2.3.2 with 90% confidence and 10% precision. In drawing the samples, each stratum was weighted by its total aggregate capacity and the population was assumed to follow a continuous distribution with an assumed coefficient of variation of 0.5.

The samples were designed to strike a balance between meeting the objectives of the evaluation, the established project timelines, and the manual effort required to collect, categorize, and share the data. While the resulting sample sizes were sufficient to meet statistical targets related to the total time for interconnection and provide insight into the nature of data tracking practices, the research team recognizes that the sample sizes were small compared to the total project populations, especially on the NEM side. In particular, the need to obtain key data fields from sampling affected the team's ability to assess tariff performance for SCE NEM projects. Because the only timeline field included in the initial data file was the project PTO date, all other dates (i.e., application submit date, date of reviews/studies, and interconnection agreement [IA] execution dates) could only be obtained for the sample of 85 projects. As a result, the research team could only conduct timeline assessments on the sample population of 85 projects, limiting the level of granularity with which results can be presented and the specificity of conclusions that can be drawn from this evaluation.

The research team did not feel that increasing the sample size and requesting manual data collection for the large number of additional projects (which would be required to obtain a representative NEM sample from SCE) would be productive for this retrospective evaluation. Instead, this limitation is highlighted as a key recommendation for future data collection and reporting efforts. Key fields necessary to conduct basic timeline analyses—for example, application submittal date, date application deemed complete, and time to complete IR—will be a necessary part of ongoing monitoring efforts and should be tracked in a readily accessible format for all projects.

2.2 Primary Source Interviews

The research team conducted primary source interviews with utility staff to collect qualitative data on Rule 21 implementation. The interviews were designed to address Objectives 1 and 2 of the research plan. Objective 1 sought to establish the current understanding of utility adherence to Rule 21, identifying all processes for which the utility is responsible. The interview responses allowed the research team to substantiate the data with the reasons provided by IOUs for delays, missed milestones, and other variable changes respective to each interconnection track. Objective 2 questions created baseline responses for a benchmarking practice among the three utilities. An overview of the qualitative interview process follows.

- The research team held pre-engagement meetings with the IOUs to discuss the research plan and expectations for the conversational interviews.
- Because of varying utility business practices, IOUs selected the correct respondents prior to the engagement.
- The Commission confirmed confidentiality of the utility personnel; this report presents anonymized responses to enable transparent dialogue.
- The interviews occurred both in person and via conference call links and included a designated interviewer and transcriber from Guidehouse to capture direct comments from the utility representatives.
- Responses were categorized by the objective categories and summarized for each utility.
- The research team confirmed responses with utility personnel prior to the results workshop.

2.2.1 IOU Interviews

The research team conducted interviews with key interconnection staff at each utility. The purpose of the interviews was twofold:

- Understand each utility’s perspective on how well parties adhere to Rule 21’s requirements
- Learn about each utility’s practices in implementing Rule 21 and resolving disputes informally when process-based issues arise

To better prepare and allocate resources to this phase of the study, the research team held clarification calls with the IOUs and summarized meeting details to enable the launch of the data collection phase. Table 11 lists the preliminary scope and expectations meetings.

Table 11. Utility Pre-Interview Overview Meetings

Utility	Interview Scope	Date
SDG&E	Data collection expectations, secure transfers, and interview process overview	October 3, 2019
SCE		October 3, 2019
PG&E		October 2, 2019

Table 12 lists the scope and date of each utility interview used in this evaluation.

Table 12. Utility Qualitative Interviews

Utility	Interview Scope	Date
SDG&E	NEM and non-NEM	January 2, 2020
SCE	NEM only	January 14, 2020
SCE	Non-NEM only	January 16, 2020
PG&E	NEM and non-NEM	January 16, 2020

The interviews were based on a stakeholder-vetted questionnaire (discussed in Section 1.2), which covered the following topics:

- **Objective 1: Rule 21 Adherence**
  - Utility and customer timelines
  - Cost accounting
  - Cost envelope option and Integrated Capacity Analysis maps
- **Objective 2: Business Practices and IOU Benchmarking**
  - Customer timelines and responsible costs
  - Customer service and communication
  - Coordination between departments and offices
  - Recordkeeping
  - Workload planning and accountability

Appendix C contains the full list of utility interview questions. While the research team used the questionnaire to guide the interviews, the discussions were also conversational and free flowing in nature. The team also conducted follow-ups for clarification and presented the results to the IOUs to confirm the information's accuracy. Response summaries are detailed in Section 6 of this report.

2.2.2 Developer Interviews

In adopting the final research plan, stakeholders proposed substituting the scoped evaluation activity to benchmark out-of-state interconnection administration with the IOUs implementing Rule 21. Stakeholders appreciated the approach to gauge Rule 21 administration compared to select states and utilities; however, they argued this would require an evaluation of equal weight, participation, and scale to effectively capture meaningful results. Interconnection requirements also vary, as the IREC, California Storage and Solar Coalition, Clean Coalition, and Green Power Institute commented. Regulatory jurisdictions may have governing deviations that present a challenge in data normalization to achieve a standardized benchmarking exercise. The research team agreed this effort would be better suited in a future evaluation or in an effort that would directly compare interconnection policies across the nation.

The research team aimed to validate data-based findings with secondary accounts of utility administration of Rule 21 through conversational interviews with developers and contractors aware of the IOU interconnection processes. The research team met with the IOUs and vested stakeholders in the fall of 2019 to develop an approach to capture supplemental knowledge and insight into the differing interconnection track concerns and constraints that typically arise from the perspective of the interconnection applicant. Guidehouse approached known developers involved in various arenas discussing interconnection enhancements, for which all were eager and available to provide insight. The opportunity to include developers also allowed a broadening of the scope of questioning to permit transparent expression of generalized sentiments progressing through the various interconnection milestones. The research team also requested interviewees provide examples of challenges, successes, and areas of improvement to aid recommendation development. Additionally, the research team encouraged discussion of project anecdotes, prior Ombudsman dispute resolutions, and areas of topical interest to learn about multiple project types, technologies, and rate schedules.

Guidehouse compiled preliminary recommendations ahead of the public results meeting to present noteworthy conclusions drawn primarily from the data analysis results. The IOU and initial four developer interviews guided recommendation development through anecdotal representation of both challenging and successful projects and examples of areas where improvement could be achievable with respects to utility adherence to Rule 21 or by way of a programmatic change through regulatory decision-making. At the results meeting, developers expressed a desire to see additional investigation into customer experience findings through continued qualitative interviews, which led to Guidehouse approaching five smaller in-state developers through introductions made by CALSSA. The additional developer interviews confirmed the research team's previous findings but revealed unique perspectives from developers with varying customer bases.

In total, the team conducted nine interviews between July and October 2020. The developers and contractors interviewed included CalCom Energy, Cenergy Power, Chico Electric, JKB Energy, Stem, Sunpower, SunStreet Energy Group, Sunworks, and Tesla.

Findings from the interviews are captured in Section 5.2 and Section 6.

2.3 Data Analysis Methodology

This section discusses the methodology used to analyze the quantitative data from each utility to assess performance relative to Rule 21. Prior to conducting any analyses, the research team performed a number of data cleaning procedures to prepare the data for analysis. The purpose of these procedures was to produce two consolidated data tables—one for NEM and one for non-NEM—containing all relevant requested fields for each utility. Data cleaning also removed projects that occurred outside of the 3-year study period. The following summarizes the data cleaning processes.

- For PG&E, the data cleaning and consolidation process involved reconstructing the database extract of 200 files and pulling out the desired project information, timeline, and cost fields. The research team compiled a list of the fields present in the data and extracted desired fields that aligned with the original data request (see Appendix B). The reconstructed database consisted of 203,728 records. The team performed a series of data checks to remove records with erroneous data, resulting in a final set of 192,288 records (192,111 NEM and 177 non-NEM). The 11,440 records removed consisted of records with:

- Duplicate notification number (project ID) values.
- Application type of distribution wholesale or a jurisdiction of FERC.
- Data missing in one of the following key data fields: application type, project status, current study process, project type, or tariff type.
- Listed generation size and inverter size equal to 0.
- PTO date that occurred outside of the study window (prior to July 1, 2016 or after June 30, 2019).
    - For records without a PTO date, the latest timeline date in the interconnection process was used instead.
    - The research team also removed a small number of projects with an application date that was prior to June 30, 2019; in some cases, the application date was as far back as 2011.

- For SCE, the data cleaning process primarily involved consolidating the initial data received with the sampled data. Few projects were removed from the dataset.
    - The NEM dataset of in-service projects only did not contain any projects with a PTO date outside of the study window, and the research team found no other reason to justify removing records.
    - For the non-NEM dataset, the team removed only one record, which had a PTO date occurring prior to application submittal. The non-NEM dataset did include non-in-service records without a PTO date, but each of these records had an application date or IA execution date within the study period.
- For SDG&E, the data cleaning process was minimal because there were relatively few data fields.
    - The NEM dataset from SDG&E was similar to the NEM data from SCE— it only included in-service projects with a PTO date within the 3-year study window. However, the research team did remove records that had a PTO date occurring one or more BD prior to the application submittal date.
    - The team did not remove any projects from the non-NEM dataset. The only modification made was to alter two projects that had a PTO date of 11/7/1948 but that should have been 11/7/2018 based on the other date fields provided.

After completing the data cleaning and consolidation process, the research team performed three main areas of analysis on each dataset:

- Project population characterization and segmentation
- Adherence to Rule 21 timelines
- Study and upgrade costs

The remainder of this section discusses the methodology used in each of these areas. Section 3 discusses results for NEM projects, and Section 4 discusses results for non-NEM projects.

2.3.1 Project Population Characterization and Segmentation Methodology

The first analysis area was characterizing and segmenting the project population according to key characteristics such as program type (e.g., Standard NEM, Non-Export), project size, technology type, and the specific Rule 21 reviews or studies performed. The research team used data in the project information fields to categorize each record according to these criteria and then summarized the project population on a per-project and an aggregate capacity basis.

The research team faced several challenges related to variations in the structure, completeness, and unique values present in key project fields across the datasets. These challenges are outlined below and detailed further in Sections 3.1 and 4.1. The team developed recommendations to address these data challenges and improve the consistency and accuracy of future evaluation efforts which are also detailed in Sections 3.1, 4.1, and 7.

Program Type and Project Status

The research team analyzed each project population and segmented them by the project type and project status. Project type refers to the specific NEM or non-NEM program such as Standard NEM, NEM Fuel Cell, NEM Aggregation, Non-Export, or Rule 21 Export.

The team actively segmented the NEM and non-NEM project populations for PG&E because the interconnection database extract PG&E sent was not already segmented. The research team classified records with a program type of Export, Non-Export, or Continuous Uncompensated Export as non-NEM. All other program types were some form of NEM and were classified as such. SCE and SDG&E sent separate files for NEM and non-NEM projects. The team did find inconsistencies in the project types listed in these files—in particular, a number of records in the non-NEM data files had NEM project types listed—but assumed that utility staff properly categorized projects into the separate files.

The segmentation by project status (e.g., in-service, study in progress, withdrawn) was performed for PG&E NEM, PG&E non-NEM, and SCE non-NEM with a focus on in-service and withdrawn projects. For the SCE NEM and SDG&E populations, the data was limited to in-service projects only.

Project Size

The research team segmented each project population into four size buckets to analyze tariff performance:

- Less than 30 kW
- 30 kW (inclusive)-100 kW
- 100 kW (inclusive)-1 MW
- 1 MW (inclusive) or greater

This segmentation intends to capture any variation in tariff performance that may have resulted from differences in the interconnection process for larger, more complex projects. Projects with a capacity less than 30 kW include traditional single-family rooftop solar systems interconnecting under expedited Standard NEM programs, which are unlikely to trigger detailed studies or system upgrades. These projects are inherently different from several hundred kW or MW-scale systems that likely serve nonresidential sectors and generally involve more complicated design and engineering considerations. Larger projects also contribute far more on a per-project basis to the total generation capacity and in this sense are more impactful. After assigning each project to the appropriate size bucket, the research team summarized the populations according to the number of projects and aggregate capacity of each bucket.

Facility Technology Type

The research team categorized projects based on their primary technology type into Solar, Storage, Other, and Unknown groups. While the technology was mostly determined from the primary technology type data field, the research team faced many complications. For example, in some cases, the listed technology type was inconsistent with a listed technology-specific program type like NEM Fuel Cell. In these cases, the team deferred to the primary technology type field.

The data structure and treatment of projects consisting of multiple technology types was inconsistent. The SCE non-NEM dataset provided the greatest visibility into the presence of multiple paired technologies as the technology field included multiple technology types when applicable. The other datasets had only one value in the technology type field, making it difficult to determine whether multiple technology types were present for a given project. The SCE NEM dataset included a separate field to note the presence of paired battery storage. However, in general, the data prevented a clear determination of which projects consisted of multiple technology types. As a result, identification of paired versus standalone systems was not always possible.

Rule 21 Reviews and Studies Performed

The final project characteristic the research team used to segment the project populations was the combination of Rule 21 review or studies performed. This categorization provides insight into the relative frequency of the various reviews and studies conducted; it was also used to inform the applicable timeline analyses for each project. In particular, the team analyzed the timeline fields for each project to determine whether each of the following were performed: IR, SR, SIS, and FS.

To identify whether a review or study occurred for a given project, the research team analyzed all timeline data fields related to the review or study. For example, determining whether SR was performed for a given project involved reviewing the Date of SR and Date SR Results Sent to Customer data fields. Any project with dates in these fields were flagged as having undergone SR. Thus, the determinations depended on the presence and accuracy of individual timeline fields related to the reviews and studies. In future studies, this method could be improved by using fields in the data files to indicate whether each review or study was performed.

The research team also attempted to identify the prevalence of projects that underwent the DGS process. Ultimately, robust data for DGS projects was not found, so DGS was not a focus of the segmentation process or the timeline analyses. The following details the DGS-related findings from each dataset.

- For the PG&E non-NEM, SCE NEM, SDG&E NEM, and SDG&E non-NEM datasets, no data indicated a project underwent the DGS process.

- In the PG&E NEM dataset, four projects had a value of DGS in the Current Study Process data field. Three of these projects had statuses indicating studies were in progress at the time of data collection; these were removed from the dataset because the latest date field populated fell outside the 3-year study window. The remaining project had a status of withdrawn and did not have data in any of the DGS-related date fields; therefore, it is not clear whether the project completed the DGS process.
- In the SCE non-NEM dataset, only two projects had data related to DGS. One project with a status of Construction was flagged as a part of DGS window #8 and the other with a status of SIS Complete was flagged as a part of DGS window #9. Because no other records were identified for these windows and given the limited data fields, the research team did not analyze the DGS aspect of these project timelines. The other timeline aspects of these projects, such as application validation and fast track, were still analyzed.

The research team's determination of the number of reviews and studies performed over the 3-year study period was based solely on the project-level data received from the data requests using the assumptions described throughout this section. Another source of data for the number of interconnection requests undergoing the various reviews or studies are the quarterly IOU interconnection data reports submitted to the CPUC per Decision 14-04-003.[10] An in-depth cross-sectional evaluation of the quarterly reports versus the data reported herein (which differ in reporting definitions and methodologies) fell beyond the scope of this report. However, the research team notes that inconsistencies across the two reports could indicate the need for improved data tracking and reporting procedures on an individual project basis and merit further review and consideration for future evaluations.

2.3.2 Timeline Analysis Methodology

Several analyses were conducted to assess how well interconnecting projects have adhered to the timelines required under Rule 21. An important role of Rule 21 is to define the interconnection process as a series of subprocesses including submitting and validating the application, conducting interconnection reviews or studies, and executing the GIA. Rule 21 describes these subprocesses as a series of steps; each step generally defines an action by a specific party and a requirement for how long that party has to complete the step. A primary objective of this evaluation was to characterize how well projects have adhered to these timelines.

2.3.2.1 Review of Timeline Requirements and Available Data

The research team focused on the processes and timeline requirements outlined in Section E (Interconnection Request Submission Process) and Section F (Review Process for Interconnection Requests) of Rule 21. The team analyzed these sections to create a map of the interconnection process and to compile a list of timeline requirements. Table 13 summarizes the steps identified by tariff process. Appendix D contains a complete list of the identified steps.

[10] IOU interconnection data reports can be found on the CPUC's website at: https://www.cpuc.ca.gov/General.aspx?id=4117.

Table 13. Summary of Tariff Steps by Process

Tariff Process	No. of Steps Identified
Expedited Provision for NEM Projects	1
Application Validation	6
Fast Track	6
Detailed Study Scoping and Agreement Execution	5
ISP	7
GIA Execution	6
Total	**31**

The specific steps that occur for projects undergoing a specific tariff process are not necessarily the same. Some steps like extensions are optional, while other steps like results meetings may or may not be chosen by the customer. Additionally, some steps do not have a time requirement, such as the time between scheduling a scoping meeting or results meeting and when the meeting actually occurs.

The research team identified dozens of specific timeline steps and requirements in the tariff. However, the data request focused on a specific set of key timeline steps from Sections E and F of the tariff:

- Total time in the application validation process
- Total time during IR
- Time between IR and notifying the customer of results
- Total time during SR
- Time between SR and notifying the customer of results
- Total time during the detailed study phase
- Total time until PTO or a similar utility-specific milestone

As discussed in Section 2.1, the data fields and formats from each utility and NEM type varied considerably. Therefore, the research team assessed the data to identify which timeline data fields were provided and developed a timeline assessment methodology that was possible with the data received. The team conducted two areas of timeline analysis:

- **Specific timeline steps and requirements defined in the tariff:** The 10 steps analyzed were chosen to be similar to the fields included in the data request. In particular, this analysis focused on requirements related to application validation, IR, SR, SIS, and GIA execution as well as the special 30-day provision for NEM projects. Section 2.3.2.2 describes the analysis in detail.
- **Total time for interconnection from application submittal to GIA or PTO:** The purpose of this analysis was to look beyond single timeline steps in the tariff and broadly characterize the total time that a project took to complete the interconnection process. Because the total time from application submittal to GIA or PTO is not a single requirement in the tariff, the research team developed a framework for this analysis based on an assessment of the tariff. Section 2.3.2.3 describes this framework and the key assumptions the team made.

2.3.2.2 Timeline Analysis of Key Tariff Steps

After assessing the timeline fields provided in each dataset, the research team selected the 10 timeline requirements shown in Table 14 for analysis. In selecting these 10 requirements out of the 31 identified in Table 13, the team considered which steps in the tariff most closely aligned with the timeline fields in the data request and which steps could be consistently analyzed for each utility given the available data. Table 14 specifies the data fields that were used to conduct each analysis and the maximum time allowed for each step according to the tariff. The table footnotes describe key assumptions used to reconcile the data received with the process outlined in the tariff.

Table 14. List of Key Tariff Requirements Analyzed

Timeline Step	Relevant Data Fields	Time Requirement
Expedited 30-Day provision for eligible NEM projects	Date application deemed complete; date GIA executed; date of AHJ Inspection; PTO date	30 BD
Time to validate application	Date application submitted; date application deemed complete	10 BD if no deficiencies
Time to resolve application deficiencies	Date of notification(s) of deficiencies; date of response(s) to notification(s) of deficiencies	10 BD for each notification and response*
Time to complete IR	Date application deemed complete; date IR results sent to customer	15 BD
Time to complete SR after IR	Date IR results sent to customer; date SR results sent to customer	30 BD†
Time to complete SIS (PG&E)	Date detailed study agreement (DSA) executed; date SIS results sent to customer	60 BD
Time to complete SIS (All)	Date IR ***or*** SR results sent to customer; date of SIS	150 BD after IR, 145 BD after SR‡
Time to send GIA to customer after IR or SR	Date IR ***or*** SR results sent to customer; date draft GIA provided to customer	15 BD
Time to send GIA to customer after SIS	Date SIS results sent to customer ***or*** date of SIS; date draft GIA provided to customer	25 BD + 30 calendar days (CD)§
Time for customer to execute GIA	Date draft GIA provided to customer; date executed GIA returned by customer	90 CD

* If there are deficiencies in the application, the tariff provides 10 BD for the utility to notify the customer of deficiencies and 10 BD for the customer to respond. If deficiencies still exist, the tariff provides 10 BD for the utility to provide a second notification of deficiencies and 10 BD for the customer to respond. The customer may use an optional 20 BD extension to respond to the first notification or the second notification but not both.

† The time between IR completion and SR completion consists of more than one step. Upon notification of IR results, the 30 BD requirement consists of 10 BD for the customer to choose to move on to SR and 20 BD for the utility to complete SR and notify the customer of the results. The customer can also choose to have an IR results meeting prior to choosing to move on to SR, which could add 25 BD to the allowed time. SCE and SDG&E provided insufficient data to determine how often IR results meetings occurred. PG&E data indicated that IR results meetings occurred for only 0.02% of projects that completed IR.

‡ Data from SCE and SDG&E did not include the date DSA executed field. Therefore, the time to complete SIS was assessed using completion of IR or SR as the starting point. The 150 BD requirement between IR and SIS includes: up to 20 BD for the customer to choose to move on to detailed study (assuming no IR results meeting), 20 BD for the utility to complete detailed study technical screens, 5 BD to establish a scoping meeting date, 15 BD after the scoping meeting for the utility to provide the DSA, 30 BD for the applicant to execute the DSA, and 60 BD after execution of the agreement for the utility to complete and issue the SIS report. After SR, the customer has 15 BD to choose to

move on to detailed studies (assuming no SR results meeting) instead of 20 BD, resulting in a total requirement of 145 BD.
§ The requirement for sending the draft GIA to the customer after SIS includes 25 BD after issuance of the SIS report to reach a mutual agreement to waive FS (assuming no SIS results meeting) followed by 30 BD for the utility to provide the draft GIA to the customer.

The first timeline step listed in Table 14 is the Expedited 30 BD provision for eligible NEM projects. Section D.13 of Rule 21 defines this provision and states that for NEM-1 generating facilities of any size or NEM-2 facilities with a capacity of 1 MW or less,[11] PTO shall normally be processed within 30 BD following the utility's receipt of:

- Completed NEM interconnection request with all required documentation and fees
- Completed and signed NEM GIA
- Confirmation of final AHJ electrical inspection clearance

The research team mapped each these dates to the date application deemed complete, date GIA executed, and date of AHJ inspection data fields, respectively. The analysis was performed by comparing these fields and noting the date that occurred the latest. Then, the time for each project was calculated as the number of BD between the latest-occurring field and the PTO date.

All three fields were not available for every utility. SCE NEM data did not include date of AHJ inspection confirmation, so results were calculated using the two available fields: date application deemed complete and date executed GIA returned by customer.

The NEM data from SDG&E included the date application deemed complete and date AHJ inspection received fields but not date GIA executed. In discussions with the research team, SDG&E staff indicated that a draft GIA is not sent to the customer until the IR is completed, so the GIA cannot be executed prior to the date application deemed complete. Therefore, calculated results for the number of BD can only be overestimations of the time between the latest-occurring field in the provision and PTO. SDG&E staff also noted that the utility countersigns the GIA upon PTO and that for small NEM projects less than 30 kW, there is no GIA execution step as customers receive an auto-generated PTO letter once the project is approved.

In the data request, the timeline fields requested were for the number of days to complete a given process, review, or study. However, the timeline data received from each utility provided the start date and completion date rather than the number of days. The research team compared the start and end dates of a given process to calculate the number of days it took. For example, to assess the 15 BD requirement for Time to Complete IR, the team calculated the number of BD between the Date Application Deemed Complete and Date IR Results Sent to Customer fields.

The research team analyzed each timeline step provided in Table 14 using all applicable projects with data available in the necessary fields. This resulted in varying and unique data subsets for each analysis. Continuing the example of Time to Complete IR, the analysis was performed for every project that had data in both the Date Application Deemed Complete and Date IR Results Sent to Customer fields, even if other key timeline fields were missing for that project. In many cases, a project would have data in one of the necessary fields but not another; in these cases, the analysis could not be performed. In the case of PG&E and SCE non-NEM

[11] Section 3 describes the difference between NEM-1 and NEM-2.

where projects with statuses other than in-service were included in the data, projects of all statuses were included in the dataset for each timeline analysis as long as the necessary fields were populated.

2.3.2.3 Total Time for Interconnection

The research team also performed a high-level analysis of the total time for interconnection from application submittal to GIA or PTO. The purpose of this analysis was to provide a more holistic picture of the total time a project took to complete the interconnection process. This total time does not reflect the performance of any single party—rather, it shows the combined performance of all parties including the utility, applicant, contractor, and any external parties.

Similar to the analysis of individual tariff steps, the total time analysis could only be performed with the subset of projects with data in all required fields. If a given project had data for Date GIA Executed by Customer, then that was used as the end date for the analysis because the GIA execution date is the end of the tariff process as outlined in Section E and F of the tariff and Appendix D. However, data for most projects did not include the GIA execution date field, so the PTO date was used instead. In these instances, the analysis overestimated the total time to the extent there is a delay between GIA execution and granting PTO.

The total time from application submittal to GIA or PTO is not a single requirement in the tariff; the actual total time the tariff allows for each project depends on which of the dozens of steps described in the tariff actually occurred. If the timeline data for each project was perfectly complete for every possible step, then the steps that each project underwent could be identified. That is, the path of each project through the tariff could be identified and a corresponding total time requirement could be obtained by summing the time requirements for each step that occurred. However, the actual data received generally did not contain enough data to determine which specific steps occurred for each project.

To address this problem, the research team developed a framework to relate the calculated total time for interconnection to the tariff's timeline requirements. The framework categorized projects by the reviews or studies performed (track) as discussed in Section 2.3.1, as generally sufficient data was available for each project. For each identified track, the research team then analyzed the tariff to identify the steps that would occur for a project that underwent those reviews or studies. As noted previously, several steps related to a given review or study are conditional or optional and may or may not contribute to the total time requirement for any particular project. Because there was insufficient data to determine which steps occurred for any particular project, the research team developed two timeline scenarios for each track—a **partial max** requirement and a **full max** requirement; these requirements are based on differing assumptions for which specific steps occur. Each requirement is obtained by summing the time allowed for each individual step assumed to occur.

The partial max requirement reflects the total allowable time a project in a given track may take assuming the project faces no major issues or added steps that cause delays. In particular, it assumes no application deficiencies, no use of optional extensions, and no results meetings.

Conversely, the full max requirement reflects the absolute maximum time a project could feasibly take if following Rule 21 as written. It assumes application deficiencies exist and that every step defined in the tariff to resolve deficiencies occurs, all optional extensions are utilized, and results meetings are chosen after every review or study.

Table 15 shows how the partial max and full max requirements were calculated for the track consisting of IR only. In this case, the partial max requirement is 105 BD, consisting of 10 BD to validate the application, 15 BD to complete IR, 15 BD to provide the draft GIA, and 90 CD for the customer to execute the GIA. The full max requirement is 180 BD because of the added steps to resolve application deficiencies and conduct an IR results meeting.

Table 15. Calculation of Total Time Requirements for IR Only

Beginning of Step	End of Step	Tariff Requirement	Partial Max Steps	Full Max Steps
Application Validation				
Application submittal	Application deemed complete	10 BD	10 BD	-
Application submittal	First notification of deficiencies	10 BD	-	10 BD
First notification of deficiencies	Customer response to first notification	10 BD + 20 BD opt. extension	-	30 BD
Applicant response to first notification	Second notification of deficiencies	10 BD	-	10 BD
Second notification of deficiencies	Customer response to second notification/ deemed complete	10 BD	-	10 BD
Fast Track: IR				
Application deemed complete	IR results sent to customer	15 BD	15 BD	15 BD
IR completed and results to customer	Customer chooses IR results meeting	10 BD + 10 BD opt. extension	-	20 BD
Customer chooses IR results meeting	Utility offers to convene IR results meeting	5 BD	-	5 BD
IOU offers to convene IR results meeting	IR results meeting occurs/ all issues resolved	Undefined	-	X*
GIA Execution				
End of fast track/ all issues resolved	Utility provides draft GIA	15 BD	15 BD	15 BD
IOU provides draft GIA	Customer executes and returns GIA	90 CD	90 CD	90 CD
Totals				
Total (sum of individual steps)			40 BD + 90 CD	115 BD + 90 CD
Total (BD)†			**105 BD**	**180 BD**

* X indicates this step is assumed to occur but that Rule 21 does not specify a required time limit for this step.

† Uses the average conversion of 90 CD equals 65 BD

Table 16 shows the calculated partial max and full max total time requirements for all six combinations of reviews and studies found and analyzed. Appendix D fully details the total requirements calculation—similar to Table 15—for each combination of reviews or studies.

Table 16. Summary of All Calculated Partial Max and Full Max Time Requirements

Reviews or Studies Performed (Track)	Partial Max Requirement (BD)	Full Max Requirement (BD)
IR	105	180
IR, SR	135	240
SIS	252	317
IR, SIS	277	377
IR, SR, SIS	312	457
IR, SR, SIS, FS	375	510

While the partial max requirement represents an ideal scenario in which a project faces no major issues or added steps, it still represents the maximum time allowed by the tariff for each step assumed to occur. Ideally, projects would move through steps in less than the allowed time and would take far less time than even the partial max requirement.

2.3.3 Study and Upgrade Cost Methodology

The characterization of study and upgrade costs associated under Rule 21 was another objective of this evaluation. Study costs refer to the defined fees for application, reviews, and engineering studies. Upgrade costs cover the investments associated with grid enhancements and mitigations to accommodate the facility's interconnection to the distribution or transmission grid. Project may also require interconnection facility costs which are the on-site electrical equipment and infrastructure necessary to integrate the facility.

The cost analysis also included an investigation of the cost envelope option, which is an optional Rule 21 provision that is meant to reduce the uncertainty associated with cost estimates. If a customer selects the envelope option and pays a fee of $2,500, then the utility has 20 BD to develop a detailed cost envelope estimate. The customer's cost responsibility is then limited to no more than 125% of the envelope estimate.

This evaluation did not include assessment of costs of total ownership, special facilities, or customer cost allowances as required by interconnection standards directed by Electric Rules 2, 15, and 16.

The cost analysis portion of the evaluation aimed to answer questions such as:

- How do estimated costs compare to actuals?
- How much of the cost burden falls to the utility versus the applicant?
- How often do upgrades occur and for what types of projects?
- How is the cost envelope option being utilized?

To answer these questions, the research team used information collected from both the quantitative data and qualitative interviews. Sections 5.1**Error! Reference source not found.** and 5.2 present cost-related results from the data requests and interviews, respectively.

In the quantitative data request, about half of fields were related to estimated and actual study and upgrade costs for the utility and customer (see Table 3 in Section 2.1 and Appendix A). However, as Table 4 summarizes, utilities indicated that many of the cost-related fields were not readily accessible or not currently tracked or documented (e.g., not in a database format and/or in a format requiring manual data collection like GIA pdf documents). The number of cost-related data fields received varied among the utilities as outlined in the following bullets.

- In the PG&E interconnection database extract, the research team identified fields for flagging projects that required upgrades and fields for estimated and actual customer, utility, and total costs for interconnection facilities and distribution upgrades. However, the data in these fields was incomplete and inconsistent. The team did not identify any fields related to fees paid for detailed studies. After performing the data cleaning procedures described at the beginning of Section 2.3, the team identified the following records with data related to upgrades.
  - Overall, 30 records had estimated upgrade costs, 9 records had actual upgrade costs, and 768 records had data indicating that upgrades were required. However, these three datasets did not overlap; together, they covered a total of 787 records.
  - 13 of the 768 projects requiring upgrades had estimated costs and 4 had actual costs. Only one project marked as requiring upgrades had *both* estimated and actual costs.
  - 17 additional projects *not* flagged as requiring upgrades had estimated costs. Of these, 3 also had actual costs.
  - 2 additional projects *not* flagged as requiring upgrades had actual costs but no estimated costs.
- SCE did not include any cost fields in the initial NEM and non-NEM data files (see Appendix B). The research team requested cost-related fields in both the NEM and non-NEM sampling requests.
  - The NEM sample request included estimated and actual cost fields for detailed studies and upgrades. However, none of the cost-related fields were populated for the sample of 85 projects. There is presumably cost-related data for other NEM projects in the population where upgrades were required, but sampling did not find any of these projects due to the limited sample size. SCE staff indicated that project-specific cost data is not maintained for NEM projects less than 1 MW because those projects are not responsible for costs.
  - The non-NEM sample request also included estimated and actual cost fields for detailed studies and upgrades. Six of the 85 sampled projects included data on detailed study costs paid by the customer and one of these included actual study costs incurred. Four of the sampled projects included data on estimated upgrade costs but none included actuals.
- For SDG&E, utility staff confirmed that no in-service projects in the 3-year study period required upgrades. Therefore, fields related to estimated and actual upgrade costs were not applicable.

The utilities also provide data for up to five recently completed applications with estimated, revised, and actual upgrade costs in the quarterly interconnection data reports submitted to the CPUC. This cost-related data is provided to the CPUC in confidential attachments. As noted previously, an in-depth analysis and comparison of the quarterly reports with data received for this evaluation was beyond the scope of this study. The research team notes that while utilities regularly report on estimated and actual upgrade costs for select projects in the quarterly reports, the separate data collection process for this evaluation indicated challenges in tracking and reporting per-project cost data for all projects in the 3-year evaluation period.

While per-project cost data was not widely and consistently accessible from the data requests, the research team did collect a considerable amount of qualitative information on upgrade costs from the utility and developer interviews. As Appendix B shows, the interview questionnaire included the following cost-related questions.

- How does the utility account for capital and O&M expenditures related to system upgrades, including customer-financed capital upgrades?
- Are there any situations where the utility required the customer to pay for grid upgrades that were not necessary at that time but were likely to be required during the span of the GIA term?
- Are there any cases where the utility charged the customer for grid upgrades that were necessary and planned irrespective of the project's interconnection?
- What common customer-responsible upgrades occur commonly? What upgrades occur rarely? Are there common upgrades that may have been part of an existing distribution plan?

In the developer interviews, cost-related discussions also included general experiences with required upgrades and the extent of differences between estimated and actual costs. Section 5.2 summarizes common cost-related findings and key themes from the interviews.

3. Results for NEM Projects

This section presents findings for the analyses outlined in Section 2.3 for NEM projects. NEM is a mechanism that allows customers who generate energy—i.e., customer-generators—to directly serve their onsite energy needs and receive financial credit for any surplus energy fed back to the distribution system.[12]

During the evaluation period (July 1, 2016 to June 29, 2019), two separate NEM tariffs were in effect in California; these are often referred to as NEM-1 and NEM-2. NEM-1, the original tariff, capped the installation size for facilities at 1 MW but did not require any interconnection fees. Interconnections under NEM-1 were capped at 5% of each utility's aggregate peak demand. Upon meeting this cap or by July 1, 2017, the IOUs switched over to NEM-2, the current tariff. This switch occurred on June 29, 2017 for SDG&E, December 15, 2016 for PG&E, and July 1, 2017 for SCE.

Under NEM-2, no installation size limit exists. However, customer-generators with systems under 1 MW must pay a one-time interconnection fee, which varies by IOU and is between $75 and $145. Customer-generators with systems over 1 MW must pay an $800 interconnection fee in addition to any transmission or distribution system upgrades. NEM-2 also requires customer-generators to adopt a time-of-use rate plan.

The default NEM program under the NEM tariff is **Standard NEM**, which generally offers an expedited interconnection process for projects sized at 30 kW or less. The IOUs implement several other NEM programs for specific interconnection circumstances:

- **Virtual NEM (V-NEM)** allows owners of multitenant properties to allocate the benefits of a solar system among multiple units.
- **NEM Aggregation (NEM-A)** allows customer-generators to aggregate the electrical load from multiple meters that are attached, adjacent, or contiguous to a single generation facility.
- **NEM Fuel Cell (NEM-FC)** is applicable to fuel cell technologies that use nonrenewable fuels and meet a greenhouse gas emissions standard.
- **Renewable Energy Self-Generation Bill Credit Transfer (RES-BCT)** allows local governments or universities to apply financial credits from a generation facility at one government-owned property to billing accounts at other properties owned by the same government entity.
- **Affordable Solar Housing Programs** include the Single-family Affordable Solar Homes (SASH) and Multifamily Affordable Solar Housing (MASH) programs. These programs, under the CSI, provide incentives for solar PV systems on qualifying affordable housing properties.

3.1 NEM Project Population Characterization and Segmentation

This section provides an overview of the population of NEM projects from the quantitative data requests received for this evaluation. For each utility, results shown include NEM project types,

[12] CPUC, "Net Energy Metering," Energy, Customer Energy Resources, accessed September 2020, https://www.cpuc.ca.gov/General.aspx?id=3800.

project status, technology types, and interconnection review or study frequency on a per-project basis and a capacity-weighted basis.

3.1.1 NEM Project Type and Project Status

From the interconnection database extract provided by PG&E, the research team was able to identify the NEM project type and project status for each project. Table 17 shows the number of NEM projects identified over the 3-year study period for PG&E, broken down by NEM project type and project status. The team identified 192,111 projects, and approximately 97.1% had a status of in-service. The Standard NEM project type accounted for approximately 95.7% of in-service projects and 94.3% of all projects.

Table 17. PG&E NEM Project Count by Project Type and Project Status

PG&E Project Type	In-Service	Withdrawn	Other	Total
Standard NEM	178,531	895	1,755	**181,181**
NEM Multi-Tariff*	4,035	440	395	**4,870**
Expanded NEM†	2,538	644	966	**4,148**
Standard NEM Paired Storage	1,185	7	225	**1,417**
V-NEM MASH	118	36	36	**190**
V-NEM	101	52	37	**190**
NEM-FC	34	10	7	**51**
V-NEM MASH Dev	2	15	11	**28**
RES-BCT	4	15	2	**21**
NEM Paired Storage	1	-	11	**12**
NEM CDCR‡	-	1	1	**2**
NEM Other Renewable	-	1	-	**1**
Total	**186,549**	**2,116**	**3,446**	**192,111**

*NEM Multi-Tariff is a PG&E program "for customers who operate a NEM-eligible generator in conjunction with a non-export of NEM fuel cell generator."[13]

† Expanded NEM is a PG&E program for industrial solar, wind, or hybrid technologies greater than 30 kW.

‡ NEM CDCR refers to NEM for the California Department of Corrections and Rehabilitation.

Table 17 also shows that around 1.1% of all NEM interconnection applications—2,116 out of 192,111—were withdrawn. This percentage varied widely depending on the project type. While only 0.5% of Standard NEM projects were withdrawn, 9% of NEM Multi-Tariff, 15% of Expanded NEM, 25% of the three types of V-NEM, and 70% of RES-BCT were withdrawn.

While Table 17 shows project counts for a simplified breakdown of in-service, withdrawn, and other projects, Table 18 shows the full list of NEM project statuses identified in the data by count and aggregate capacity. The table shows that the 97.1% of in-service projects accounted for 72.7% of aggregate capacity. Withdrawn projects were 1.1% of NEM projects by count but 13.0% of aggregate capacity. These withdrawn projects may not accurately reflect lost or

[13] PG&E, "Guidelines for NEM and Storage Paired System," last updated December 2018, https://www.pge.com/pge_global/common/pdfs/solar-and-vehicles/net-energy-metering/net-energy-metering-overview/nem-multiple-tariff/NEM-Paired-Storage-Frequently-Asked-Questions.pdf

foregone capacity if they were later resubmitted and approved under a new record. In future data requirements, the Commission should consider mechanisms to identify or link records for withdrawn projects that are later resubmitted.

Aside from the decommissioned status, which accounted for only 0.2% of aggregate capacity, the remaining statuses reflecting projects in various stages of the interconnection process at the time of data extraction represented 14.1% of aggregate capacity.

Table 18. PG&E NEM Full List of Project Statuses

PG&E Project Status	Count	Aggregate Capacity (MW)	% of Aggregate Capacity
In-service	186,549	1,511.9	72.7%
Withdrawn	2,116	271.2	13.0%
Application review in progress	1,070	85.8	4.1%
Study in progress	728	33.5	1.6%
IA in progress	591	77.6	3.7%
Decommissioned	430	3.8	0.2%
Implementation	307	85.8	4.1%
Application pending signature	140	0.8	0.04%
Application submitted	127	1.2	0.06%
Application accepted	53	9.4	0.5%
Total	**192,111**	**2,081.0**	**100%**

Table 19 shows the number of SCE NEM projects identified over the 3-year study period—134,838 projects. Data on NEM project types was limited to projects that applied under the NEM-1 tariff prior to July 1, 2017 and those that applied under the NEM-2 tariff.

Table 19. SCE NEM Project Count by Project Type

SCE Project Type	Count
NEM-2	86,306
NEM-1	48,532
Total	**134,838**

Table 20 shows the number of SDG&E NEM projects identified over the 3-year study period—71,303 projects. The data received from SDG&E included a detailed breakdown of NEM project types, which is also displayed in the table. Standard NEM projects accounted for approximately 94.0% of projects, followed by NEM paired storage at approximately 5.2%.

Table 20. SDG&E NEM Project Count by Project Type

SDG&E Project Type	Count
Standard NEM-2	66,995
NEM Paired Storage	3,696
NEM-A (ST Agg Bill Meter)	341
SASH	141
V-NEM MASH	46
V-NEM (NEM-V-ST)	39
Standard NEM-1	19
NEM-A (Agg Bill Meter)	14
NEM-A (2-ST, Agg NGOM)	9
V-NEM (NEM-V)	3
Total	**71,303**

The NEM project data from SCE and SDG&E was for in-service projects only. The omission of other project statuses from SCE and SDG&E limits this study. Data for projects with another status, particularly withdrawn projects, is important to understanding the context of tariff performance, especially to the extent that timeline delays or upgrade cost burdens caused withdrawals. Future reporting requirements should confirm that detailed information on withdrawn projects is included along with in-service projects.

A comparison of the project type values provided by the utilities also highlights the need for ongoing reporting requirements to confirm detailed project types are provided for every NEM project. Requirements should provide a mechanism for reconciling differences in reported permutations or variations on the NEM programs to allow for comparability between the utilities. While some permutations are a result of the 3-year evaluation period covering projects under both the NEM-1 and NEM-2 tariffs, other permutations such as those for V-NEM and NEM-A could be clarified or combined depending on the level of granularity desired.

3.1.2 Project Size Breakdown

Table 21 breaks down PG&E's NEM project applications by the four different size buckets discussed in Section 2.3.1. The table includes all project statuses, including withdrawn projects. For each bucket, the table shows the number of projects as an absolute number and a percentage of the total, the mean project size in kW, the total aggregate capacity in MW, and the percent contribution to the total aggregate capacity.

Table 21. PG&E NEM Project Size and Capacity Breakdown

Size Bucket	PG&E Count	% of Count	Mean Project Size (kW)	Aggregate Capacity (MW)	% of Aggregate Capacity
Less than 30 kW	188,090	97.91%	5.9	1,108	53.2%
30-100 kW	1,940	1.01%	55.9	109	5.2%
100 kW-1 MW	1,987	1.03%	309.0	614	29.5%
1 MW or greater	94	0.05%	2,669.3	251	12.1%
Total	**192,111**	**100%**	**10.8**	**2,081**	**100%**

While projects less than 30 kW made up a vast majority—almost 98%—of the number of projects, they composed only 53.2% of the aggregate capacity. Projects between 30 kW and 100 kW were relatively small in both number and aggregate capacity. Projects greater than 100 kW represented only 1% of applications but contributed over 40% of the aggregate capacity.

Table 22 shows a similar SCE NEM project size breakdown. As discussed previously, NEM data for SCE reflects only in-service projects. Projects less than 30 kW also make up a vast majority of the number of projects but not the aggregate capacity. Projects greater than 100 kW made up less than 0.8% of projects but around a third of aggregate installed capacity.

Table 22. SCE NEM Project Size and Capacity Breakdown

Size Bucket	SCE Count	% of Count	Mean Project Size (kW)	Aggregate Capacity (MW)	% of Aggregate Capacity
Less than 30 kW	133,073	98.69%	5.8	769	63.30%
30-100 kW	715	0.53%	56.2	40	3.31%
100 kW-1 MW	1,022	0.76%	343.8	351	28.93%
1 MW or greater	28	0.02%	1,936.3	54	4.46%
Total	**134,838**	**100%**	**9.0**	**1,215**	**100%**

Table 23 shows the size breakdown of SDG&E NEM projects, reflecting in-service projects only. From both a project count and aggregate capacity perspective, the distribution of NEM projects for SDG&E was skewed toward smaller projects compared to PG&E and SCE. The 99% of projects under 30 kW accounted for almost 75% of aggregate capacity, while 0.5% of projects greater than 100 kW accounted for just over 20% of aggregate capacity.

Table 23. SDG&E NEM Project Size and Capacity Breakdown

Size Bucket	SDG&E Count	% of Count	Mean Project Size (kW)	Aggregate Capacity (MW)	% of Aggregate Capacity
Less than 30 kW	70,516	98.90%	5.6	395	75.05%
30-100 kW	423	0.59%	55.9	24	4.50%
100 kW-1 MW	361	0.51%	288.8	104	19.82%
1 MW or greater	3	0.00%	1,118.6	3	0.64%
Total	**71,303**	**100%**	**7.4**	**526**	**100%**

3.1.3 Facility Technology Type Breakdown

The research team also segmented the project population by generation technology type, specifically separating out the solar and storage projects from all others. The team also attempted, with limited success, to distinguish between standalone storage and storage paired with another technology type for each utility.

Table 24 shows the PG&E NEM project breakdown by technology type. The research team used the data in the technology type and project type fields to categorize projects into solar, storage, other, and unknown.

Table 24. PG&E NEM Count by Technology Type and Size with Paired and Standalone Storage Types

PG&E Technology Type	Less than 30 kW	30-100 kW	100 kW-1 MW	1 MW or greater	Total
Solar	184,776	1,924	1,891	64	**188,655**
Paired Storage	2,356	5	18	2	**2,381**
Standalone Storage	1	-	2	-	**3**
Other	350	2	68	16	**436**
Unknown	607	9	8	12	**636**
Total	**188,090**	**1,940**	**1,987**	**94**	**192,111**

Table 24 shows PG&E NEM storage projects broken out into standalone storage and paired storage. The process for categorizing the projects by technology type, including the determination of standalone versus paired storage, is as follows.

All projects were initially categorized into solar, storage, other, and unknown categories according to the value in the technology type data field.

- Projects with solar PV and storage in the technology type data field were mapped to the solar and storage categories, respectively.
- Projects categorized as other (435) included fuel cells (57), wind (17), engines (12), microturbines (3), and hydro (3). The remaining projects (343) were simply listed as other in the raw data and could not be identified.

- Projects with missing data in the technology type field (710) were categorized as unknown.

The team then compared the technology type and project type fields for each record, resulting in a number of modifications or exceptions to the initial mapping of solar, storage, other, and unknown. The values displayed in Table 24 are after accounting for these modifications and exceptions (described as follows and summarized in Table 25).

- 1,429 records with the project type NEM Paired Storage or SNEM Paired Storage were recategorized as paired storage. These records included those in which the primary technology type field was populated with solar PV (1,281), storage (75), other (2), and blank/unknown (71).
- 952 records with the project type NEM-MT and the technology type storage were recategorized as paired storage. PG&E's NEM-MT program is applicable to paired storage devices that are "sized larger than 150% of the NEM-eligible generator's max output capacity." [14] Another 3,918 records had the NEM-MT project type but had values of solar (3,229), other (355), or unknown (334) in the technology type field. Many of these records may also be paired storage systems, but the data did not clearly indicate this.
- Three records with a technology type of storage were reclassified as standalone storage. These had a project type of Expanded NEM (2) and Standard NEM (1).
- Three records with a blank value in the technology type field were recategorized from unknown to other because the project type was NEM-FC. The research team found an inconsistency for two records that had a project type of NEM-FC but a technology type of solar PV. These two records were categorized as solar according to the technology type.

Table 25. Technology Type Mapping Exceptions for PG&E NEM

Value in Technology Type Field	Value in Project Type Field	Technology Mapping
Solar PV, Storage, Other, or blank	NEM Paired Storage or SNEM Paired Storage	Paired storage
Storage	NEM Multi-Tarif	Paired storage
Storage	Expanded NEM or Standard NEM	Standalone storage
Blank	NEM-FC	Other
Solar PV	NEM-FC	Solar

The data did not clearly indicate which projects involved only a single technology type and which involved multiple technology types. In particular, the technology type field alone did not reveal all projects that appeared to include energy storage components. The data also did not clearly indicate which storage projects were standalone and which were paired with other generation installed concurrently or prior to the storage system.

[14] PG&E," Guidelines for NEM and Storage Paired System," last updated December 2018, https://www.pge.com/pge_global/common/pdfs/solar-and-vehicles/net-energy-metering/net-energy-metering-overview/nem-multiple-tariff/NEM-Paired-Storage-Frequently-Asked-Questions.pdf.

Given the uncertainty with the standalone storage and paired storage determinations, the research team combined these categories into a single storage category, as shown in Table 26. Using a single storage category for PG&E also better aligns with the data for the other utilities, which also lacked clear differentiation between standalone and paired storage.

Table 26. PG&E NEM Count by Technology Type and Size with Single Storage Category

PG&E Technology Type	Less than 30 kW	30-100 kW	100 kW-1 MW	1 MW or greater	Total
Solar	184,776	1,924	1,891	64	**188,655**
Storage	2,357	5	20	2	**2,384**
Other	350	2	68	16	**436**
Unknown	607	9	8	12	**636**
Total	**188,090**	**1,940**	**1,987**	**94**	**192,111**

Table 27 shows the same technology type breakdown for PG&E on an aggregate capacity basis rather than a per-project basis.

Table 27. PG&E NEM Aggregate Capacity by Technology Type and Size

PG&E Technology Type	Less than 30 kW	30-100 kW	100 kW-1 MW	1 MW or greater	Total
Solar	52.1%	5.2%	27.9%	8.1%	**93.3%**
Storage	0.8%	0.01%	0.2%	0.4%	**1.4%**
Other	0.1%	0.004%	1.3%	1.8%	**3.2%**
Unknown	0.2%	0.02%	0.1%	1.7%	**2.0%**
Total	**53.2%**	**5.2%**	**29.5%**	**12.1%**	**100%**

Table 28 presents the SCE NEM project breakdown by technology type. In the SCE NEM data, storage did not appear in the main technology type field. Instead, the data included a separate field that flagged whether the project included a storage system. In every case where the data indicated the presence of a storage system, another type was listed in the technology type field. Therefore, every project that was flagged for including a storage system appeared to reflect a paired storage system. All but one of these 4,163 paired storage projects were paired with solar; the one exception was a pairing with the Hybrid – Mixed technology type. As with the PG&E categorization, the flagged storage projects were simply categorized as storage. The research team was unable to identify standalone storage projects given the format and structure of the data.

Table 28. SCE NEM Project Count by Technology Type and Size

SCE Technology Type	Less than 30 kW	30-100 kW	100 kW-1 MW	1 MW or greater	Total
Solar	129,082	699	797	20	**130,598**
Storage	3,988	15	158	2	**4,163**
Other	3	1	67	6	**77**
Total	**133,073**	**715**	**1,022**	**28**	**134,838**

The 77 projects listed as other for SCE consisted of the following technology types:

- Fuel Cell – Non-Renewable (53)
- Fuel Cells (10)
- Hydroelectric <30 MW (3)
- Hybrid – Mixed (3)
- Wind (3)
- Diesel (1)
- Digester Gas (1)
- Biomass (1)
- Fuel Cell – Renewable (1)

Table 29 shows the same technology type breakdown for SCE on an aggregate capacity basis rather than a per-project basis.

Table 29. SCE NEM Aggregate Capacity by Technology Type and Size

SCE Technology Type	Less than 30 kW	30-100 kW	100 kW-1 MW	1 MW or greater	Total
Solar	61.0%	3.2%	22.4%	3.2%	**89.9%**
Storage	2.3%	0.1%	4.6%	0.2%	**7.1%**
Other	0.001%	0.005%	1.9%	1.1%	**3.0%**
Total	**63.3%**	**3.3%**	**28.9%**	**4.5%**	**100%**

Table 30 shows the SDG&E project technology breakdown. In the data received, 3,696 projects had advanced energy storage populated in the technology type data field. All of these storage projects had a value of NEM/PRD – NEM pair w/ AES in the project type field, therefore appearing to represent paired storage systems. However, the data did not otherwise indicate if the storage was paired with another generation type or the technology it was paired with. Similar to the SCE NEM data, the research team was unable to identify standalone storage projects given the format and structure of the data and categorized the projects simply as storage.

Table 30. SDG&E NEM Project Count by Technology Type and Size

SDG&E Technology Type	Less than 30 kW	30-100 kW	100 kW-1 MW	1 MW or greater	Total
Solar	66,822	418	325	2	**67,567**
Storage	3,657	5	33	1	**3,696**
Other	37	-	3	-	**40**
Total	**70,516**	**423**	**361**	**3**	**71,303**

The 40 projects listed as other for SDG&E consisted of 37 projects with the value of Solar/Wind and three internal combustion engine projects.

Table 31 shows the SDG&E NEM technology type breakdown on an aggregate capacity basis rather than a per-project basis.

Table 31. SDG&E NEM Aggregate Capacity by Technology Type and Size

SDG&E Technology Type	Less than 30 kW	30-100 kW	100 kW-1 MW	1 MW or greater	Total
Solar	71.1%	4.4%	18.2%	0.4%	**94.2%**
Storage	3.9%	0.1%	1.2%	0.2%	**5.4%**
Other	0.1%	-	0.3%	-	**0.4%**
Total	**75.0%**	**4.5%**	**19.8%**	**0.6%**	**100%**

As noted throughout this section, the research team faced several challenges in identifying technology types in the data. In particular, the utilities differed in their methods of reporting projects with energy storage components and projects occurring on a site with existing generation equipment. The current format and structure of technology type data tracking complicates the identification of projects with multiple onsite generation technologies. Future data tracking and reporting requirements should:

- Confirm all reported projects have a listed generation technology.
- Provide flexibility for reporting multiple technology types when an interconnecting project consists of multiple technologies or when the interconnecting project is an addition to an existing facility. In these cases, the existing technology type(s) and capacity should also be reported.
- Distinguish between paired storage and standalone storage.
- Establish data validation checks to confirm that reported technology types are consistent with reported project types (e.g., confirm projects interconnecting under NEM-FC do not have non-fuel cell entries in the technology type field).

3.1.4 Rule 21 Reviews and Studies Performed

While the data received from each utility typically included an indication of the interconnection process type (e.g., fast track, detailed study, ISP), the research team also worked to identify the specific reviews and studies that each project underwent during the interconnection process. As discussed in Section 2.3.1, this required analyzing all relevant timeline data for a given project and using the presence of data in fields related to a specific study to indicate that study occurred for a given project.

Table 32 breaks down the reviews and studies found for PG&E's NEM projects. Among the records with data indicating that at least one review or study was performed, 98.8% had data indicating that only IR was conducted. After IR, the most common other reviews or studies performed were SR, followed by SIS. The timeline data did not clearly indicate projects that completed an interconnection FS under the ISP track.

SR and SIS occurred much more frequently for larger projects than for smaller projects. Only 0.01% of projects under 30 kW underwent these studies, while 16.8% of projects between 100 kW and 1 MW and 58.6% projects 1 MW or greater projects did. These percentages do not include 2,905 projects (1.5% of total); these projects did not have data in fields for any review or study and were categorized as could not determine. Most of these projects (2,329) had a project status of withdrawn or a status indicating that the project was still in the application validation phase. However, 576 projects had a project status of in-service, study in progress, IA in progress, or implementation. While these statuses indicated that at least one review or study was performed or in progress, the research team could not identify which reviews or studies were done.

Table 32. PG&E NEM Reviews and Studies Count by Project Size

PG&E Reviews/ Studies Performed	Less than 30 kW	30-100 kW	100 kW- 1 MW	1 MW or greater	Total
IR	185,816	1,673	1,321	26	**188,836**
IR, SR	20	26	192	26	**264**
SIS	-	2	13	10	**25**
IR, SIS	-	1	3	2	**6**
IR, SR, SIS	1	9	60	5	**75**
Could not determine	2,253	229	398	25	**2,905**
Total	**188,090**	**1,940**	**1,987**	**94**	**192,111**

Table 33 presents the number of reviews and studies for PG&E NEM projects broken down by generation technology type rather than project size. This data shows that SR and SIS occurred for 0.18% of solar projects, 0.34% of storage projects, and 6.1% of other projects.

Table 33. PG&E NEM Reviews and Studies Count by Technology Type

PG&E Reviews/ Studies Performed	Solar	Storage	Other	Unknown	Total
IR	185,542	2,313	384	597	**188,836**
IR, SR	232	7	22	3	**264**
SIS	20	-	-	5	**25**
IR, SIS	6	-	-	-	**6**
IR, SR, SIS	71	1	3	-	**75**
Could not determine	2,784	63	27	31	**2,905**
Total	**188,655**	**2,384**	**436**	**636**	**192,111**

As discussed in Section 2.1.1, timeline data for SCE NEM projects was not provided in the initial data file; this prohibited a fully representative characterization of project timelines, including the reviews and studies performed. Timeline data collected in the additional sample of 85 NEM projects yielded the results shown in Table 34. Among the 85 sampled projects, 84 underwent IR only, while one project sized 1 MW or greater also underwent SR.

Table 34. SCE NEM Reviews and Studies Count by Project Size

SCE Reviews/ Studies Performed	Less than 30 kW	30-100 kW	100 kW-1 MW	1 MW or greater	Total
IR	75	1	4	4	**84**
IR, SR	-	-	-	1	**1**
Could not determine	132,998	714	1,018	23	**134,753**
Total	**133,073**	**715**	**1,022**	**28**	**134,838**

Table 35 shows that the sample of 85 SCE NEM projects included 78 solar, four storage, and two other projects. The large project that underwent SR was a solar project.

Table 35. SCE NEM Reviews and Studies Count by Technology Type

SCE Reviews/ Studies Performed	Solar	Storage	Other	Total
IR	78	4	2	**84**
IR, SR	1	-	-	**1**
Could not determine	130,519	4,159	75	**134,753**
Total	**130,598**	**4,163**	**77**	**134,838**

For SDG&E, the timeline data indicated that all NEM projects underwent only IR, as shown in Table 36. Interconnection staff at SDG&E confirmed in follow-up discussions that all in-service NEM projects in the 3-year study period underwent IR only.

Table 36. SDG&E NEM Reviews and Studies Count

SDG&E Reviews/ Studies Performed	Count
IR	71,303
Total	**71,303**

The research team recommends that future data and reporting requirements confirm utilities provide data in the fields tracking the reviews and studies performed for each project in addition to fields with the length of time for each review and study. These fields should be provided in an accessible, granular format, eliminating the need for follow-up data requests. The Commission should mandate these fields are reported for every project to eliminate uncertainty that could hamper further research and evaluation. Requiring that these fields use binary (true/false) values would more clearly indicate whether each review or study was performed for a given project. This requirement would streamline the segmentation of the population and eliminate the need to review each timeline field separately.

3.2 NEM Timelines: Key Tariff Steps

This section presents NEM results for the timeline analysis of key tariff steps described in Section 2.3.2.2. The results for each step are presented for each utility and are broken down by project size and technology where applicable.

3.2.1 Expedited 30-Day Provision for NEM Projects

As discussed in Section 2.3.2.2, the research team assessed timelines related to the expedited 30-day provision for eligible NEM projects outlined in Section D.13 of Rule 21. Because all three fields were not available for every utility (SCE NEM data did not include date of AHJ inspection confirmation and there is no SDG&E GIA execution step), results for SCE and SDG&E are most likely overestimations of the time between the latest-occurring field in the provision and PTO.

Table 37 shows PG&E results by project size and technology type. The table shows the number of projects for which the analysis was performed, the mean and standard deviation in BD, and the percentage that met the 30-day requirement. The mean time was 6.3 BD, and 96.3% of projects met the requirement. Projects less than 30 kW and solar projects performed especially well compared to larger projects and projects of other technology types.

Table 37. PG&E NEM 30-Day Provision Results

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 30 BD
By Project Size				
Less than 30 kW	183,589	5.5	16.6	96.9%
30-100 kW	1,288	60.8	90.2	54.0%
100 kW-1 MW	1,024	75.6	102.3	52.1%
1 MW or greater	7	30.4	47.8	71.4%

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 30 BD
By Project Technology Type				
Solar	183,006	5.8	19.6	96.8%
Storage	2,009	35.0	48.8	63.9%
Other	349	51.4	66.7	48.7%
Unknown	544	22.6	44.0	81.3%
Total	**185,908**	**6.3**	**20.8**	**96.3%**

Table 38 presents SCE NEM results for the 30-day provision. As with all timeline analyses for SCE NEM, the analysis could only be performed with the limited sampled projects rather than the entire population. The research team performed the analysis for 82 of the 85 sampled NEM projects because three projects were NEM-2 facilities greater than 1 MW and not subject to the 30-day provision. SCE staff noted that deeming an application complete requires a completed application, completed and signed IA, AHJ inspection sign-off, and a valid single-line diagram.

The mean time found from the sampled project wet was 9.3 BD and 90.1% of projects met the requirement. The combined 90.1% adherence rate is the weighted result across the size-based sampling strata discussed in Section 2.1.2. For example, the 90.7% result for projects less than 30 kW was weighted by the proportion of projects less than 30 kW in the total population (98.7%) rather than the proportion in the sample (75 out of 85 or 88.2%). As with PG&E, projects less than 30 kW and solar projects performed better than larger or non-solar projects. These results should not be taken to represent the entire NEM project population. SCE staff stated that the quarterly compliance rate with the 30-day provision has been over 99% in the last few years.

Table 38. SCE NEM 30-Day Provision Results

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 30 BD
By Project Size				
Less than 30 kW	75	8.9	20.0	90.7%
30-100 kW	4	52.8	52.9	50.0%
100 kW-1 MW	2	33.5	37.5	50.0%
1 MW or greater	1	27.0	-	100%
By Project Technology Type				
Solar	76	9.5	20.1	90.8%
Storage	4	46.5	58.5	50.0%
Other	2	33.5	37.5	50.0%
Total	**82**	**9.3**	**20.3**	**90.1%**

Table 39 shows the SDG&E NEM 30-day results. The mean time was 3.6 BD, and 99.1% of projects met the requirement. The result for projects less than 30 kW and solar projects was better than larger and non-solar projects, but the difference was less pronounced than for other utilities.

Table 39. SDG&E NEM 30-Day Provision Results

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 30 BD
By Project Size				
Less than 30 kW	70,473	3.4	7.3	99.2%
30-100 kW	418	14.8	22.0	87.8%
100 kW-1 MW	358	13.7	18.5	89.4%
1 MW or greater	1	153.0	-	0%
By Project Technology Type				
Solar	67,520	3.6	7.6	99.1%
Storage	3690	3.3	8.2	98.9%
Other	40	3.2	3.5	100%
Total	**71,250**	**3.6**	**7.6**	**99.1%**

Figure 7 and Figure 8 are histograms for PG&E and SDG&E showing the distribution in results for the 30-day provision. As these figures show, the vast majority of projects received PTO in just a few BD—these are most often solar projects sized less than 30 kW. A histogram is not shown for SCE because of the low count of projects analyzed, which stemmed from the required sampling.

Figure 7. Histogram of NEM 30-Day Provision Results for PG&E

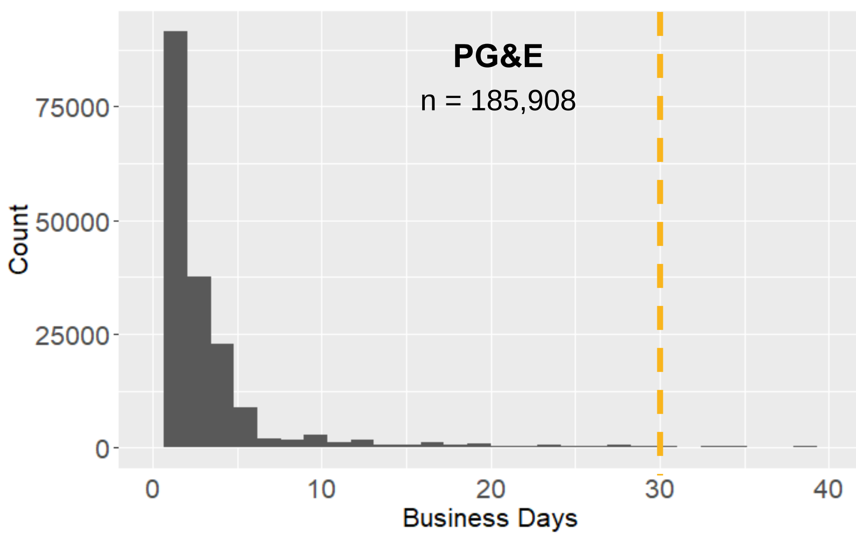


Figure 8. Histogram of NEM 30-Day Provision Results for SDG&E

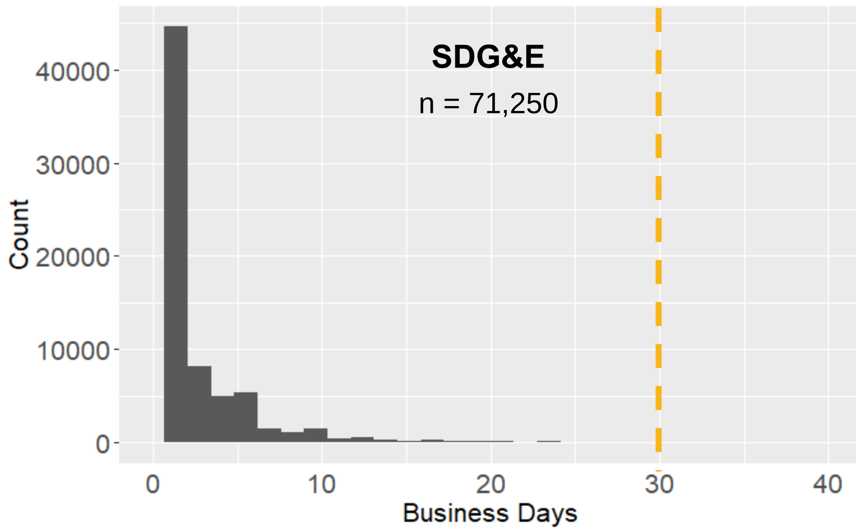


Figure 9 and Figure 10 are histograms for projects between 30 kW and 100 kW and projects greater than 100 kW. After removing the large majority of projects sized less than 30 kW, the distribution for PG&E is broader and reflects an increased time to PTO for larger projects (i.e., greater than 30 kW) relative to small (i.e., less than 30 kW) projects.

Figure 9. PG&E NEM 30-Day Provision Results by Project Size

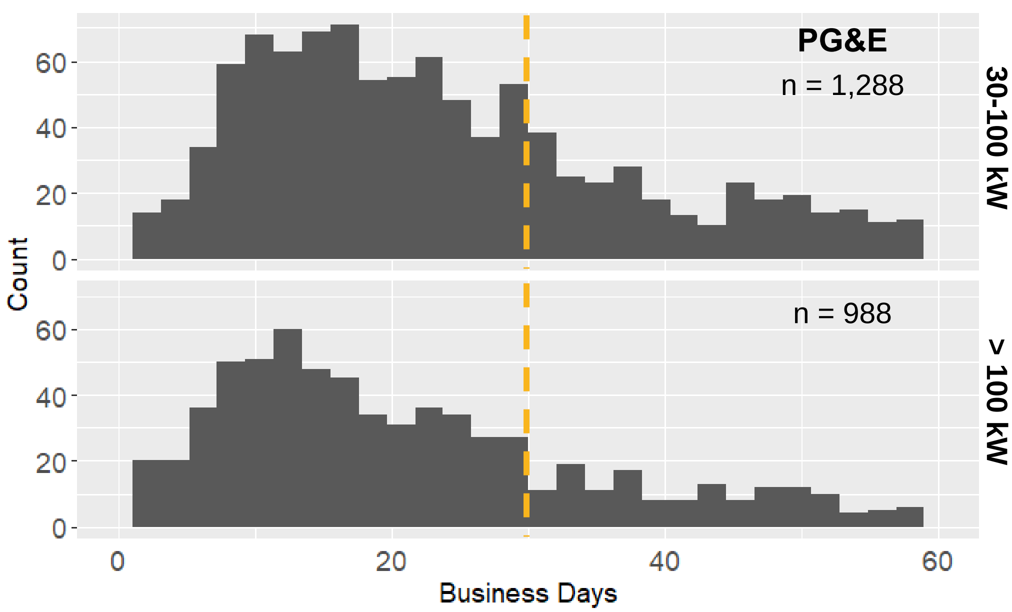
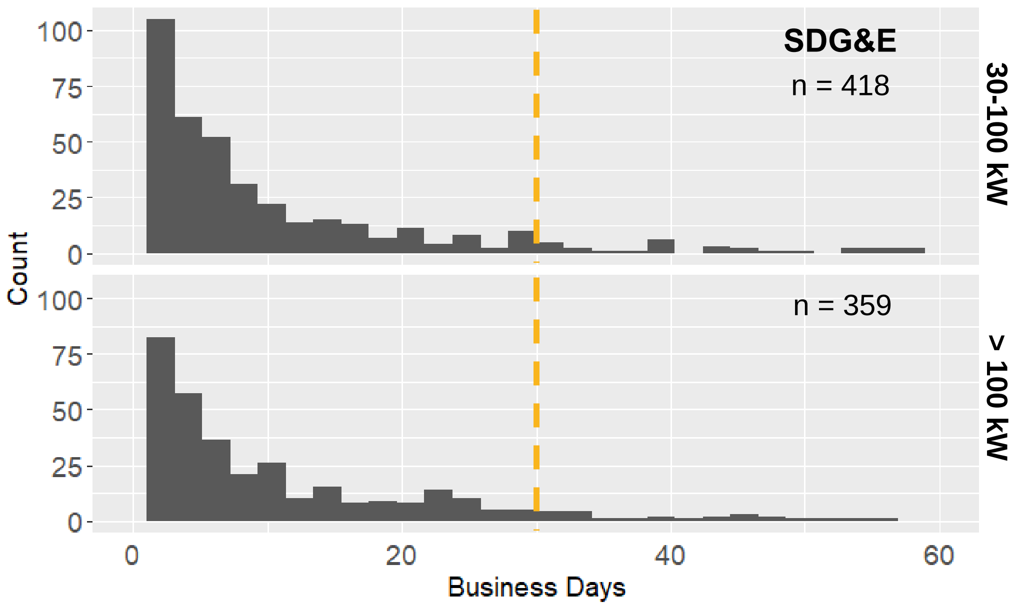


Figure 10. SDG&E NEM 30-Day Provision Results by Project Size



3.2.2 NEM Time to Validate Application

The research team calculated the time to validate the interconnection application as the number of BD between application submittal and date application deemed complete. The team did not perform the analysis for any project missing either of these dates. If an application does not have any deficiencies, this step should take no more than 10 BD. If an application has deficiencies, Rule 21 provides additional time to resolve them (as discussed in Section 3.2.3).

Table 40 shows the PG&E NEM results for time to validate application broken down by project size and technology type. In total, 86.7% of projects completed the step in 10 BD or less, with an overall mean of 7.7 BD; this result is a because projects less than 30 kW and solar projects performed well. Projects greater than 30 kW and non-solar projects had a mean time of 20-30 BD, suggesting that deficiencies lengthened the time required to validate applications.

Table 40. PG&E NEM Time to Validate Application

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 10 BD
By Project Size				
Less than 30 kW	185,331	7.2	18.8	87.6%
30-100 kW	1,711	32.1	48.9	39.6%
100 kW-1 MW	1,624	37.9	54.5	33.4%
1 MW or greater	71	22.0	23.6	26.8%

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 10 BD
By Project Technology Type				
Solar	185,904	7.5	19.8	87.3%
Storage	1,841	23.8	34.2	43.8%
Other	396	19.9	23.9	45.7%
Unknown	596	25.9	36.6	52.2%
Total	**188,737**	**7.7**	**20.2**	**86.7%**

Table 41 shows the SCE NEM results for the time to validate applications. The dataset for this analysis was limited to the 85 sampled projects. The research team calculated the overall result, finding that 96.3% of projects completed the step in 10 BD or less by weighting the results within each sampling stratum by its proportion in the overall NEM population. This overall result was driven largely by less than 30 kW solar projects. Larger projects and non-solar projects took considerably longer, suggesting that application deficiencies were more often present for these projects.

Table 41. SCE NEM Time to Validate Application

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 10 BD
By Project Size				
Less than 30 kW	75	3.5	4.1	97.3%
30-100 kW	1	121.0	-	0%
100 kW-1 MW	4	102.0	114.7	25.0%
1 MW or greater	5	35.4	24.6	20.0%
By Project Technology Type				
Solar	79	7.8	20.2	91.1%
Storage	4	76.0	123.2	50.0%
Other	2	22.0	21.2	50.0%
Total (sample weighted)	**85**	**4.9**	**5.0**	**96.3%**

Table 42 shows the SDG&E NEM results for the time to validate applications, finding that 97.4% of all projects completed the step in 10 BD or less. Compared to the other utilities, the results varied little by technology type. However, project size did appear as a moderate factor, with larger projects requiring longer to validate.

Table 42. SDG&E NEM Time to Validate Application

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 10 BD
By Project Size				
Less than 30 kW	67,196	2.6	6.9	97.5%
30-100 kW	418	10.3	26.5	86.4%
100 kW-1 MW	337	16.4	47.3	81.0%

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 10 BD
1 MW or greater	3	26.0	21.8	33.3%
By Project Technology Type				
Solar	64,349	2.6	7.9	97.4%
Storage	3,566	3.6	8.8	96.1%
Other	39	3.0	2.6	97.4%
Total	**67,954**	**2.7**	**8.0**	**97.4%**

3.2.3 NEM Time to Resolve Application Deficiencies

The research team assessed the time to resolve application deficiencies using the timeline fields for date(s) of notification of deficiencies by the utility and date(s) of customer response to notification of deficiencies. This section presents combined results for the following steps described in the tariff.

1. Time from application submittal to the first notification of deficiencies by the utility
2. Time for customer to respond to the first notification of deficiencies
3. Time from customer response to the first notification to the second notification of deficiencies by the utility
4. Time for customer to respond to second notification of deficiencies
5. Time between the final customer response to a notification of deficiencies and the date the application is deemed complete by the utility

Rule 21 provides 10 BD for each of these steps. Each project with data on deficiencies varied in the number of notifications and responses required, though most required only one notification and response. Rather than presenting these five steps separately, the research team combined results for all projects with data for the first, third, and fifth steps requiring utility action. Similarly, the team combined results for all projects with data for the second and fourth steps requiring customer responses.

Table 43 shows the PG&E NEM results for the utility time to provide deficiency notifications. Table 44 shows results for the time customers took to respond to deficiency notifications. Utility notifications took an average of 8.8 BD and met the requirement 83.9% of the time; customer responses took an average of 17.2 BD and met the requirement 61.0% of the time. In both cases, there was no clear trend in performance across projects of different sizes or technologies.

Table 43. PG&E NEM Time to Provide Notification of Application Deficiencies

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 10 BD
By Project Size				
Less than 30 kW	55,435	8.2	22.7	84.6%
30-100 kW	1,239	18.2	49.0	71.3%

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 10 BD
100 kW-1 MW	1,261	24.1	58.5	64.2%
1 MW or greater	116	6.7	13.4	93.1%
By Project Technology Type				
Solar	55,894	8.6	24.5	84.0%
Storage	1,400	13.3	35.8	78.6%
Other	100	13.1	20.9	73.0%
Unknown	657	13.0	33.1	81.6%
Total	**58,051**	**8.8**	**25.0**	**83.9%**

Table 44. PG&E NEM Time to Respond to Notification of Application Deficiencies

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 10 BD
By Project Size				
Less than 30 kW	28,787	16.8	28.7	61.1%
30-100 kW	611	27.2	53.3	60.1%
100 kW-1 MW	573	29.3	59.2	55.3%
1 MW or greater	55	14.1	16.9	58.2%
By Project Technology Type				
Solar	28,818	17.2	30.2	60.9%
Storage	824	14.6	30.6	69.3%
Other	331	23.3	33.9	50.2%
Unknown	53	22.7	47.4	67.9%
Total	**30,026**	**17.2**	**30.3**	**61.0%**

Table 45 and Table 46 show the SCE NEM results for utility deficiency notifications and customer responses. The overall strata-weighted result was an average of 10.5 BD for utility notifications and 3.4 BD for customer responses. In both cases, the 10 BD requirement was met around 90% of the time. The project counts show that results are largely reflective of less than 30 kW solar projects. Counts for the subsets of larger and non-solar projects are small, so results for these subsets should not be taken as representative of the full population.

Table 45. SCE NEM Time to Provide Notification of Application Deficiencies

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 10 BD
By Project Size				
Less than 30 kW	32	10.4	38.4	90.6%
30-100 kW	3	25.3	17.8	33.3%
100 kW-1 MW	4	5.0	4.1	100%
1 MW or greater	8	18.5	16.4	37.5%

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 10 BD
By Project Technology Type				
Solar	43	12.3	34.3	79.1%
Storage	2	8.5	0.7	100.0%
Other	2	16.5	10.6	50.0%
Total	**47**	**10.5**	**38.1**	**90.4%**

Table 46. SCE NEM Time to Respond to Notification of Application Deficiencies

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 10 BD
By Project Size				
Less than 30 kW	17	3.3	5.9	94.1%
30-100 kW	2	21.0	8.5	0%
100 kW-1 MW	2	4.0	1.4	100%
1 MW or greater	4	7.5	3.4	75.0%
By Project Technology Type				
Solar	23	5.5	7.5	82.6%
Storage	1	3.0	-	100%
Other	1	6.0	-	100%
Total	**25**	**3.4**	**5.9**	**93.7%**

The SDG&E NEM data did not include dates for the notification or response to application deficiencies; therefore, the research team did not conduct this analysis. The results from the application validation step in Table 42 suggest that few SDG&E NEM projects face deficiencies that require more than 10 BD to resolve.

The PG&E results suggest that customer response steps were more often delayed than the utility notification steps, while the SCE results suggest the opposite. Prior to drawing a conclusion on the relative performance of utility versus applicant steps in resolving deficiencies, the Commission should confirm the dates recorded by the utilities for customer responses to deficiencies reflect the date the customer sent the response and not the date the response was processed or acknowledged.

Beyond the qualitative assessment of timeline performance for the steps related to resolving deficiencies, the research team also identified qualitative reasons for deficiencies and other flagged issues from the data samples for SCE and SDG&E. Similar qualitative data was not collected for PG&E because sampling was not required.

- For SCE, the most common deficiencies and flagged issues included issues with supporting documentation like mismatched inverter and equipment information between applications and single-line diagrams and issues with project sizing such as oversizing or incomplete sizing justifications.
- For SD&GE, the most common deficiencies and flagged issues included incorrect rate selections or missing drawings.

3.2.4 NEM Time to Complete IR

The research team calculated the time to complete IR as the time between the date that the application was deemed complete and the date that initial review results were provided to the customer. The tariff allows up to 15 BD for the utility to complete this step. The team performed this analysis for every project with data in the two required fields.

Table 47 shows the PG&E NEM results for time to complete IR. The overall result (96.9% adherence with a mean of 3.1 BD) was driven by the vast majority of projects in the less than 30 kW and solar technology categories. Adherence rates were slightly lower (around 85%) for the storage and unknown technology categories and significantly lower (50%-60%) for the other technology category and the size categories larger than 30 kW.

Table 47. PG&E NEM Time to Complete IR

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 15 BD
By Project Size				
Less than 30 kW	185,487	2.7	8.9	97.5%
30-100 kW	1,627	22.3	41.2	64.8%
100 kW-1 MW	1,508	27.4	52.9	63.3%
1 MW or greater	58	23.9	33.7	51.7%
By Project Technology Type				
Solar	185,406	2.9	10.6	97.2%
Storage	2,285	11.7	23.4	85.0%
Other	401	15.6	21.7	68.8%
Unknown	588	11.1	32.0	86.7%
Total	**188,680**	**3.1**	**11.1**	**96.9%**

Table 48 shows the SCE NEM results for time to complete IR. Because the required timeline fields were obtained via sampling, the research team could only perform the analysis for the sample of 85 projects. Data for 21 of the 85 projects had an application deemed complete date occurring after the date for IR results sent to customer, hence the negative mean values in the table. SCE staff indicated that they provide IR responses to customers within 10 BD of submission regardless of whether the project is deemed valid or deficiencies were identified. Thus, if an application does have deficiencies, the IR completion date can occur prior to the resolution of application deficiencies.

Table 48. SCE NEM Time to Complete IR

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 15 BD
By Project Size				
Less than 30 kW	75	-0.4	4.4	100%
30-100 kW	1	-29.0	-	100%
100 kW-1 MW	4	-6.5	10.7	100%

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 15 BD
1 MW or greater	5	3.4	27.5	80.0%
By Project Technology Type				
Solar	79	-0.3	7.6	98.7%
Storage	4	-4.8	11.5	100%
Other	2	-14.0	21.2	100%
Total	**85**	**-0.6**	**4.4**	**100%**

The SDG&E NEM data did not include a field for date IR results provided to customer, so the research team could not conduct the analysis. As Table 23 shows, all but 3 of the 71,303 SDG&E NEM projects were less than 1 MW and thus subject to the expedited 30-day provision for NEM projects. Results for the 30-day provision in Table 39 show that over 99.1% of analyzed projects met the 30-day provision. Because all of these NEM projects underwent only IR (see Table 36), this 99.1% result also indicates that IR was not a major cause of delay for SDG&E NEM projects.

3.2.5 NEM Time to Complete SR

The research team assessed the time to complete SR using the date that IR results were sent to the customer and the date SR results were sent to the customer. As noted in Table 14, multiple steps may occur between these dates, and the research team used a requirement of 30 BD assuming no IR results meeting; these 30 BD consist of 10 BD for the customer to choose to move on to SR and 20 BD for the utility to complete SR and notify the customer of the results.

Table 49 shows the PG&E NEM results for time to complete SR after IR. Overall, 66.8% of projects met the requirement, with a mean of 30.0 BD. Across the size categories, performance trended better for smaller projects and worse for larger projects. Performance across the technology categories was relatively consistent around the overall mean.

Table 49. PG&E NEM Time to Complete SR after IR

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 30 BD
By Project Size				
Less than 30 kW	20	23.6	28.9	85.0%
30-100 kW	35	22.1	14.3	80.0%
100 kW-1 MW	245	31.2	34.1	66.1%
1 MW or greater	31	33.7	15.6	45.2%
By Project Technology Type				
Solar	297	30.3	32.3	67.3%
Storage	7	27.4	13.8	68.0%
Other	25	26.9	15.8	57.1%
Unknown	2	35.5	0.7	0%
Total	**331**	**30.0**	**31.0**	**66.8%**

The time to complete SR analysis could only be performed for SCE NEM using the sample set. SR was performed in only one of the 85 sampled projects, a solar project sized greater than 1 MW. For this project, SR was completed 29 BD after completion of IR.

The time to complete SR analysis was not applicable to the SDG&E NEM dataset because no projects underwent SR.

3.2.6 NEM Time to Complete SIS

As Table 14 shows, the research team performed two assessments for the time to complete SIS:

- The first assessment used the date of DSA execution as a starting point and was possible only for PG&E; this is a single step in Rule 21 with a timeline requirement of 60 BD.
- The second analysis, which could be performed for all three utilities, used the date of IR completion or SR completion as the starting point. The requirement for this analysis was 150 BD after IR or 145 BD after SR, assuming the customer does not choose an IR or SR results meeting.

Table 50 shows PG&E NEM results for time to complete SIS using the date of DSA execution. Overall, 34.4% of projects assessed met the 60 BD requirement, though the mean time was around 60 BD. In contrast, Table 51 shows an overall result of 95.3% adherence when using the date of IR completion or date of SR completion as the starting point. This result suggests that other steps in the 145 or 150 BD requirement besides completing the SIS itself (e.g., selecting to move on to detailed study, completing detailed study screens and a scoping meeting, and executing the DSA) are completed well within the time allowed by Rule 21.

Table 50. PG&E NEM Time to Complete SIS after DSA Execution

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 60 BD
By Project Size				
Less than 30 kW	1	89.0	-	0%
30-100 kW	2	62.0	22.6	50.0%
100 kW-1 MW	17	61.2	13.6	29.4%
1 MW or greater	12	57.1	13.9	41.7%
By Project Technology Type				
Solar	26	59.0	14.0	38.5%
Other	2	67.0	31.1	50.0%
Unknown	4	68.0	10.7	0%
Total	**32**	**60.6**	**14.6**	**34.4%**

Table 51. PG&E NEM Time to Complete SIS after IR or SR

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 150 BD*
By Project Size				
Less than 30 kW	2	141.0	21.2	50.0%
30-100 kW	19	96.2	33.4	100%
100 kW-1 MW	117	93.7	34.1	95.7%
1 MW or greater	12	110.7	35.5	91.7%
By Project Technology Type				
Solar	143	95.6	33.5	95.8%
Other	6	121.5	30.0	83.3%
Storage	1	2.0	-	100%
Total	**150**	**96.0**	**34.4**	**95.3%**

* Time requirement is 150 BD after IR but 145 BD after SR.

The time to complete SIS could not be analyzed for SCE NEM projects. As Table 34 shows, completion of SIS could not be confirmed for any projects in the full population or any of the 85 sampled projects. The research also did not perform the analysis for SDG&E NEM because it was not applicable to any project—the team confirmed with SDG&E staff that no NEM projects during the 3-year study period completed SIS.

3.2.7 NEM Time to Send GIA to Customer

The research team assessed the steps associated with the utility sending a draft GIA to the customer upon completion of IR, SR, or SIS. As Table 14 shows, Rule 21 provides 15 BD after completing IR or SR and 30 CD plus 25 BD after completing SIS for the utility to send the draft GIA. The research team performed the analysis for all projects that had data for the latest review or study data and the date the draft GIA was sent to the customer.

Table 52 shows PG&E NEM results for time to send a draft GIA after completion of IR or SR. Overall, 82.3% of projects met the 15 BD requirement. Results were best for projects in the 30 kW-1 MW range and solar projects.

Table 52. PG&E NEM Time to Send GIA to Customer after IR or SR

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 15 BD
By Project Size				
Less than 30 kW	603	27.4	61.1	71.8%
30-100 kW	817	18.0	70.7	87.8%
100 kW-1 MW	735	13.5	55.6	85.6%
1 MW or greater	13	20.2	17.7	46.2%

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 15 BD
By Project Technology Type				
Solar	2,047	18.3	62.5	83.6%
Storage	70	31.2	46.2	52.9%
Other	29	9.4	13.6	79.3%
Unknown	22	69.9	148.1	63.6%
Total	**2,168**	**19.1**	**63.2**	**82.3%**

Table 53 shows the PG&E NEM results for time to send a draft GIA after completing SIS. The overall result of 90.6% adherence and a mean of 17.2 BD is well within the 30 CD plus 25 BD requirement.

Table 53. PG&E NEM Time to Send GIA to Customer after SIS

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 30 CD + 25 BD
By Project Size				
30-100 kW	6	5.7	11.4	100%
100 kW-1 MW	33	12.3	30.5	97.0%
1 MW or greater	14	33.8	18.5	71.4%
By Project Technology Type				
Solar	45	10.6	15.2	95.6%
Storage	1	171.0	-	0%
Other	2	21.5	21.9	100%
Unknown	5	44.2	8.8	60.0%
Total	**53**	**17.2**	**27.8**	**90.6%**

Table 54 shows the SCE NEM results for time to send a draft GIA to the customer after completing IR or SR for the sampled set of 85 projects. The overall mean time was a negative 32.5 days, which suggests that GIA execution for many NEM projects occurs at the beginning of the interconnection process (time of application submittal) rather than after reviews or studies are completed. The overall weighted adherence rate relative to the 15 BD requirement was 97.9%. An SCE NEM analysis for the time to send a draft GIA after completing SIS was not applicable because no project in the sampled dataset completed SIS.

Table 54. SCE NEM Time to Send GIA to Customer after IR or SR

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 15 BD
By Project Size				
Less than 30 kW	75	-32.9	49.1	98.7%
30-100 kW	1	27.0	-	0%
100 kW-1 MW	4	-15.5	50.2	75.0%

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 15 BD
1 MW or greater	5	47.2	64.4	20.0%
By Project Technology Type				
Solar	79	-26.2	47.5	93.7%
Storage	4	-63.3	108.8	75.0%
Other	2	28.0	117.4	50.0%
Total	**85**	**-32.5**	**48.9**	**97.9%**

The time to send a draft GIA analysis was not performed for SDG&E NEM because the dataset did not include a GIA execution date. SDG&E staff did confirm that a draft GIA for NEM projects is sent after engineering reviews such as IR are completed rather than at the time of application submittal. The steps for sending a draft GIA after completion of SR and SIS were not relevant because no SDG&E NEM projects completed SR or SIS.

3.2.8 NEM Time for Customer to Execute GIA

The final tariff step analyzed was the time for the customer to execute the GIA. Rule 21 provides 90 CD for the GIA to be executed once the utility sends it, which is after reviews and studies are completed. The research team assessed this step for all projects with data for the date draft GIA provided to customer and date executed GIA returned by customer fields.

Table 55 shows the PG&E NEM results for time to execute the GIA. Overall, three-quarters of projects executed the GIA in 90 CD or less, with a mean time of 66.4 CD. There was not a clear trend among results by the size or technology categories. The analysis was not performed for SDG&E NEM because the data did not include GIA execution date fields.

Table 55. PG&E NEM Time for Customer to Execute GIA

Category	Count	Mean (CD)	Std. Dev. (CD)	Percent ≤ 90 CD
By Project Size				
Less than 30 kW	455	57.2	76.6	79.1%
30-100 kW	658	64.0	85.9	76.7%
100 kW-1 MW	581	76.8	97.2	69.2%
1 MW or greater	17	52.7	56.3	88.2%
By Project Technology Type				
Solar	1,614	67.1	88.2	74.7%
Storage	53	70.6	83.9	71.7%
Other	24	20.9	25.8	95.8%
Unknown	20	56.8	90.3	80.0%
Total	**1,711**	**66.4**	**87.7**	**74.9%**

Table 56 shows the SCE NEM results for the time to execute the GIA among the sample of 85 projects. The weighted overall adherence rate was 89.1%, with a mean time of 39.9 CD.

Table 56. SCE NEM Time for Customer to Execute GIA

Category	Count	Mean (CD)	Std. Dev. (CD)	Percent ≤ 90 CD
By Project Size				
Less than 30 kW	75	40.0	65.6	89.3%
30-100 kW	1	0.0	-	100%
100 kW-1 MW	4	63.0	68.2	50.0%
1 MW or greater	5	32.2	67.0	80.0%
By Project Technology Type				
Solar	79	36.6	59.0	88.6%
Storage	4	92.3	137.7	75.0%
Other	2	76.5	106.8	50.0%
Total	**85**	**39.9**	**65.3**	**89.1%**

3.3 NEM Total Time for Interconnection

As discussed in Section 2.3.2.3, the research team assessed the total time for interconnection from application submittal to GIA or PTO for each project based on the reviews or studies performed to provide a more complete picture of the total time a project took to complete the interconnection process. This section presents the results of this analysis for NEM projects.

For PG&E, most records did not have data in the GIA execution date field. Where this was available, the team used it to calculate the total time; however, for the remaining projects, PTO date was used. Table 57 shows the PG&E NEM results for total time for interconnection from application to GIA or PTO. The table shows that the mean total time for interconnection was only 14.5 BD for projects that underwent IR only, but several hundred BD for projects with additional reviews or studies. Projects in the IR track met the full max requirement over 99% of the time. Projects in the remaining tracks also met the full max requirement over 95% of the time except for the IR and SR track, which was considerably lower at 68.3%.

Table 57. PG&E NEM Total Time to GIA or PTO Full Results

Track	Count	Mean (BD)	% Meeting Partial Max	% Meeting Full Max
All Projects				
IR	186,787	14.5	97.3%	99.1%
IR, SR	221	201.8	48.9%	68.3%
SIS	21	141.8	81.0%	95.2%
IR, SIS	4	228.8	100%	100%
IR, SR, SIS	65	249.4	66.2%	96.9%
Total	**187,098**	**14.8**	**97.2%**	**99.0%**

Table 58 and Table 59 show results specifically for projects sized 100 kW or greater and non-solar projects, respectively. Results for each track are generally comparable with those in Table 57; one execption is the IR-only track, which captures the vast majority of projects. For the IR-only track, isolating projects greater than 100 kW causes the mean time to increase to 150 BD and the proportion meeting the full max requirement to fall to 68.6%. Performance is also worse among the subset of non-solar projects. These results indicate that small NEM projects— in particular small NEM solar projects—that only require IR complete the interconnection process far quicker and within the required timelines far more often than larger projects, non-solar projects, and projects that require additional reviews or studies.

Table 58. PG&E NEM Total Time to GIA or PTO Results for 100 kW-Plus Projects

Track	Count	Mean (BD)	% Meeting Partial Max	% Meeting Full Max
Projects Sized 100 kW or greater				
IR	1,167	150.6	44.3%	68.6%
IR, SR	179	204.6	50.3%	68.7%
SIS	19	146.1	78.9%	94.7%
IR, SIS	4	228.8	100%	100%
IR, SR, SIS	57	251.5	68.4%	96.5%
Total	**1,426**	**161.6**	**46.6%**	**70.1%**

Table 59. PG&E NEM Total Time to GIA or PTO Results for Non-Solar Projects

Track	Count	Mean (BD)	% Meeting Partial Max	% Meeting Full Max
Non-Solar Projects				
IR	2,969	61.7	80.3%	94.3%
IR, SR	24	145.3	79.2%	87.5%
SIS	5	246.8	60.0%	80.0%
IR, SR, SIS	3	134.0	100%	100%
Total	**3,001**	**62.8**	**80.2%**	**94.3%**

The SCE NEM sampled dataset included the GIA execution date for every project, so this date was used to calculate the total time for interconnection rather than PTO date. Table 60 shows the SCE NEM results for total time from application submittal to GIA execution. The overall mean time was 24.6 BD, primarily driven by the 21.7 BD mean for IR-only projects. Only one project in the sample required an additional study (SIS); this project took 269 BD from application to GIA execution, which exceeded the 135 BD partial max and 240 BD full max requirement (see Table 16). Conclusions for the overall timeline performance of SCE NEM projects that perform SR should not be made on the basis of this single project.

Table 60. SCE NEM Total Time to GIA Execution Full Results

Track	Count	Mean (BD)	% Meeting Partial Max	% Meeting Full Max
All Projects				
IR	84	21.7	94.0%	98.8%
IR, SR	1	269.0	0%	0%

Total	**85**	**24.6**	**92.9%**	**97.6%**

Table 61 shows IR-only track results for the subset of projects sized at 100 kW or greater and the subset of non-solar projects. The mean time of 110 BD for these larger projects was much longer than the mean of 21.7 BD for projects of all sizes. Non-solar projects also took longer to interconnect—83.0 BD, on average—than the broader population. This result suggests that, as with PG&E, small NEM solar projects tend to complete the interconnection process much quicker and more often within the required timelines than larger, non-solar projects.

Table 61. SCE NEM Total Time for Large and Non-Solar Projects – IR Only

Dataset	Count	Mean (BD)	% Meeting Partial Max	% Meeting Full Max
Projects sized 100 kW or greater	8	110.0	50.0%	87.5%
Non-solar projects	6	83.0	66.7%	83.3%

Table 62 shows the SDG&E NEM results for total time for interconnection. For SDG&E, the total time was calculated using the PTO date because GIA execution date was not provided. All SDG&E NEM projects required IR only, so the table rows show results for the full dataset, the subset of projects sized at 100 kW or greater, and the subset of non-solar projects rather than different tracks. Among all projects, the mean time from application to PTO was only 11.8 BD and almost 99% of projects met the partial max requirement. However, the subset of 100 kW or greater projects took longer on average—110.6 BD from application to PTO.

Table 62. SDG&E NEM Total Time to PTO Full Results

Dataset	Count	Mean (BD)	% Meeting Partial Max	% Meeting Full Max
All projects	71,303	11.8	98.8%	99.6%
Projects sized 100 kW or greater	364	110.6	54.4%	82.1%
Non-solar projects	37,36	15.2	97.6%	98.9%

3.4 Summary of NEM Findings and Recommendations

The research team analyzed the quantitative data for NEM projects to characterize the project population for each utility and assess timeline performance. This section summarizes key findings and recommendations for improving data collection and timeline performance.

3.4.1 Project Population Characterization and Segmentation

The research team summarized the NEM population for each utility based on the project type, project size, technology type, and Rule 21 reviews or studies performed. The following bullets outline the key findings and recommendations related to each of these project characteristics.

NEM Project Types

Key findings related to segmentation by NEM project type include the following.

- PG&E and SDG&E data differentiated between NEM program types like Standard NEM, NEM-A, and V-NEM while SCE NEM data did not.
- The specific names used for variants or different versions of NEM programs were different for PG&E and SDG&E.
- For both PG&E and SDG&E, the vast majority of projects were standard NEM. The next most common program types were NEM Multi-Tariff and Expanded NEM for PG&E and NEM Paired Storage for SDG&E.

Recommendations for improving data reporting to allow for the identification, segmentation, and comparison of project populations by NEM project type include the following.

- Data should include detailed project types for each project to identify non-standard NEM projects such as V-NEM, NEM-A, and SASH/MASH. These project types are inherently complex and often have unique application considerations that could contribute to differences in timeline performance. Additional detail could also be valuable for improving oversight and regulatory design in the future.
- Requirements should provide flexibility for reconciling differences in the naming or treatment of different NEM programs between the utilities. Some permutations such as those for V-NEM and NEM-A differ by utility and could be clarified or combined depending on the level of granularity desired.

NEM Project Statuses

Key findings for the segmentation by NEM project status include the following.

- PG&E NEM data included all project statuses while SCE and SDG&E data included only in-service projects; the omission of other project statuses from SCE and SDG&E limits this study.
- For PG&E, in-service projects were 97% of all projects by count but only 73% of aggregate capacity. Withdrawn projects were around 1% of all records by count and 13% of aggregate capacity. The withdrawal rate was significantly higher for non-standard NEM program types.

Recommendations related to the tracking of NEM project statuses include the following.

- Data must include withdrawn projects in addition to in-service projects. While there may be complications with reporting all project statuses such as those associated with projects in the middle of the review process, data at a minimum should include withdrawn projects in addition to in-service projects.
- Future requirements should consider mechanisms to identify or link records for withdrawn projects that are later resubmitted. Withdrawn projects may not accurately reflect lost or foregone capacity if they were later resubmitted and approved under a new record.

NEM Project Sizes

Key findings from the segmentation into size categories of less than 30 kW, 30 kW-100 kW, 100 kW-1 MW, and 1 MW or greater include the following.

- Projects less than 30 kW accounted for between 97% and 99% of NEM projects by count for all three utilities. However, these projects accounted for a smaller proportion of aggregate capacity—53% for PG&E, 63% for SCE, and 75% for SDG&E.

- For all three utilities, projects greater than 100 kW accounted for a significant proportion of aggregate capacity—42% for PG&E, 33% for SCE, and 20% for SDG&E—despite accounting for at most 1% of projects by count.

For this evaluation, the research team weighted timeline results for all projects equally regardless of size because every project was a valid observance of timeline performance. However, it may be appropriate to use size-weighted results in future studies or to otherwise focus future evaluation efforts on larger projects that contribute a disproportionately large amount to aggregate capacity but are more likely to suffer from missed timelines.

NEM Technology Types

The research team faced several challenges in identifying technology types in the data. Key findings from the segmentation of projects by technology include the following.

- In the PG&E and SDG&E NEM datasets, storage appeared in the main technology type field. However, there was no indication of other technology types present for these records, so it was not clear which were standalone or paired storage systems.

- In the SCE NEM data, storage did not appear in the main technology type field. Instead, the data included a separate field which flagged whether the project consisted of a storage system. In every case where the data indicated the presence of a storage system, there was another type listed in the technology type field.

- For all three utilities, NEM datasets were dominated by solar projects. The small proportion of non-solar projects included primarily storage but also very small numbers of many other technologies.

The following are recommendations for tracking and reporting technology type fields.

- Future data requirements should confirm that all reported projects have a listed generation technology and encourage consistency across the utilities by using agreed-upon dropdown values and mappings.
- Requirements should provide flexibility for reporting multiple technology types when an interconnecting project consists of multiple technologies or when the interconnecting project is an addition to an existing facility. In these cases, the existing technology type(s) and capacity should also be reported.
- Data should clearly distinguish between paired storage and standalone storage systems.
- Datasets should include validation mechanisms to check that reported technology types are consistent with reported project types (e.g., to check that projects interconnecting under NEM fuel cell do not have non-fuel cell entries in the technology type field).

NEM Reviews and Studies Performed

Key findings related to the segmentation by reviews and studies performed include the following.

- For PG&E, the reviews and studies performed could not be determined for around 1.5% of NEM records. Among the remaining records, 99.8% underwent only IR. SR and SIS did also occur and were more likely for larger projects.
- The full SCE NEM data did not include fields related to reviews or studies performed. Among the sample of 85 projects, one project underwent IR and SR while the rest underwent only IR.
- For SDG&E, all NEM projects required only IR.

The primary recommendation for improving tracking of reviews and studies performed is that data should include separate binary (true/false) fields that indicate whether IR, SR, SIS, and FS were completed for each project. These fields should be separate from the timeline or date fields for each review or study. This would reduce uncertainty associated with using date fields to determine which reviews or studies occurred and allow evaluators to clearly identify which timeline steps were relevant for each project.

3.4.2 Rule 21 Timeline Performance

Table 63 summarizes NEM results for the analysis of key timeline steps discussed in Section 3.2. The table shows that the steps analyzed, and the number of records analyzed in each step varied among the utilities depending on the available data and applicability to the project population. In particular, key findings related to the completeness and scope of the timeline analysis include the following.

- All NEM timeline analyses for SCE relied on the sample set of 85 projects. The sample was too small to fully represent of the subpopulation of larger projects, non-solar projects, and projects that required reviews or studies beyond IR.
- A number of steps for SCE and SDG&E were not analyzed due to lack of data. By contrast, the comprehensive database extract provided by PG&E allowed for analysis of all key steps.
- Steps related to SR and SIS were not applicable to SDG&E because no projects in the NEM dataset of in-service projects required SR or SIS.

Table 63. Summary of NEM Key Tariff Step Timeline Results

Timeline Step*	PG&E Count	PG&E % Met	SCE Count†	SCE % Met	SDG&E Count	SDG&E % Met
Expedited 30-day provision for NEM projects	185,908	96.3%	82	90.1%	71,250	99.1%
Time to validate application	188,737	86.7%	85	96.3%	67,954	97.4%
Time to notify customer of application deficiencies	58,051	83.9%	47	90.4%	Not analyzed‡	
Time to respond to notification deficiencies	30,026	61.0%	25	93.7%	Not analyzed‡	
Time to complete IR	188,680	96.9%	85	100%	Not analyzed	

Timeline Step*	PG&E Count	PG&E % Met	SCE Count†	SCE % Met	SDG&E Count	SDG&E % Met
Time to complete SR after IR	331	66.8%	1	Met§	Not applicable**	
Time to complete SIS after DSA Execution	32	34.4%	Not analyzed		Not applicable	
Time to complete SIS after IR or SR	150	95.3%	Not analyzed		Not applicable	
Time to send GIA to customer after IR or SR	2,168	82.3%	85	97.9%	Not analyzed	
Time to send GIA to customer after SIS	53	90.6%	Not analyzed		Not analyzed	
Time for customer to execute GIA	1,711	74.9%	85	89.1%	Not analyzed	

* See Table 14 for the tariff-derived timeline requirements for each step.

† All timeline analysis for SCE NEM were based on the sampled dataset of 85 projects. The inability to obtain a fully representative set of timeline data was a major limitation of this evaluation.

‡ Not analyzed means that the analysis was not performed due to missing or incomplete data.

§ Met indicates that the single project for which the timeline analysis was conducted met the timeline requirement. Because the analysis population was only one project, a percentage result is not shown.

** Not applicable means that the step was not relevant to any project in the project population

Key findings from Table 63 related to timeline performance include the following.

- PG&E NEM timeline performance for the key steps analyzed ranged between 34% and 97%. The steps with the highest adherence rate were the expedited 30-day NEM provision, completing IR, and sending a draft GIA to the customer after completion of reviews or studies. The steps with the lowest adherence rate were responding to deficiency notifications, completing SR, and completing SIS after DSA execution. SR and SIS do not occur for most projects but are often delayed when they do occur.
- SCE NEM timeline performance could not be robustly assessed because timeline analyses could only be performed for the 85 sampled projects. Among the sampled projects, adherence rates for the key steps analyzed were around 90% or greater. The sample did not include projects requiring SR or SIS, so these steps were not assessed.
- SDG&E NEM timeline performance was only assessed for two steps: the expedited 30-day NEM provision and the time to validate the application. Data needed to assess other timeline steps was unavailable or not applicable. However, the steps that were analyzed had very high adherence rates and there was generally little indication of delays.

The research team also broke down results for each timeline step by project size and generation technology type categories. Assessing at this additional level of granularity led to the following key findings.

- For PG&E, the adherence rate for a number of timeline steps was lower for larger projects than for small projects. In particular, adherence rates for the NEM 30-day provision and the time to validate the application, time to complete IR, time to complete SR, and time to send draft GIA steps were noticeably lower for projects greater than 30 kW than projects less than 30 kW. For these steps, delays are more common for larger projects.

  - The adherence rate for these timeline steps also tended to be lower for non-solar projects than for solar projects, especially for the NEM 30-day provision and the time to validate the application and time to complete IR steps. However, the relatively small number of non-solar projects often led to small analysis counts, which limits the ability to make strong conclusions.

- For SCE, the limited number of sampled NEM projects prevented drawing strong conclusions about the relative timeline performance of smaller versus larger projects and solar versus non-solar projects. Adherence rates were lower for larger projects in many steps, but the sample size of projects greater than 30 kW was only 10.
- For SDG&E, the adherence rates for larger projects were also lower than smaller projects for the two steps analyzed, but to lesser extent than the other utilities. For these two steps, there was no significant difference in the adherence rates for solar and non-solar projects.

The research team also performed a high-level analysis of the total time for interconnection from application submittal to GIA execution or PTO to gain a broad understanding of the total time a project took to complete the interconnection process. Section 3.3 discusses the results of this analysis for NEM projects and the following key finding.

- Across all three utilities, small NEM projects complete the interconnection process far quicker and within the required timelines far more often than larger projects. This is also true for NEM solar projects compared to other technology types and NEM projects that require only IR compared to those that require additional reviews or studies.

4. Results for Non-NEM Projects

This section presents findings for the analyses outlined in Section 2.3 for non-NEM projects. Non-NEM broadly consists of the Non-Export and Export project types:

- **Non-Export** projects are facilities not permitted to transfer electrical energy back to the host utility. Such facilities are sized such that the generation output will serve onsite load only. Non-Export is commonly used for energy storage facilities intended to serve or backup onsite load but not deliver energy back to the grid. For the purposes of interconnection timelines, all Non-Export projects are eligible for the fast track evaluation process regardless of capacity.
- **Export** projects, also called Rule 21 Export, are facilities permitted to transmit electrical energy back to the host utility but that do not fall under the purview of NEM. These include qualifying facilities that sell power based on the utility's avoided cost.

Rule 21 does not apply to the interconnection of facilities participating in wholesale electricity markets under the jurisdiction of the FERC. These projects typically apply for interconnection under the WDAT or the California Independent System Operator Tariff.[15] Such projects were not within the scope of this evaluation.

4.1 Non-NEM Project Population Characterization and Segmentation

This section provides an overview of the population of non-NEM projects from the quantitative data requests received for this evaluation. For each utility, results shown include project types, project status, technology types, and interconnection review or study frequency on a per-project basis and a capacity-weighted basis.

4.1.1 Non-NEM Project Type and Project Status

The research team was able to identify non-NEM project types and project statuses for each project from the interconnection database extract PG&E provided. Table 64 shows that only 177 non-NEM projects across three project types were identified over the 3-year study period for PG&E (compared with over 192,000 NEM projects). Approximately 93% of both in-service projects and all projects had the Non-Export project type.

Table 64. PG&E Non-NEM Project Count by Project Type and Project Status

PG&E Project Type	In-Service	Withdrawn	Other	Total
Non-Export	58	59	47	**164**
Continuous Uncompensated Export	4	3	5	**12**
Export	-	1	-	**1**
Total	**62**	**63**	**52**	**177**

Notably, 35.6% of non-NEM interconnection applications were withdrawn compared with only around 1% of NEM applications. Table 65 shows counts and aggregate capacity for the full list

[15] CPUC, "Rule 21 Interconnection," Electric, Interconnection, accessed September 2020, https://www.cpuc.ca.gov/General.aspx?id=3962.

of non-NEM project statuses identified in the PG&E data. Withdrawn and in-service projects both accounted for around 35% of projects. The remaining 30% of records had statuses reflecting various stages of the interconnection or implementation process at the time of data extraction.

On an aggregate capacity basis, Table 65 shows that records with a status of implementation accounted for the largest proportion of aggregate capacity at 48.6%. Withdrawn projects represented 31.6% of aggregate capacity, while in-service projects represented only 7.9%. As noted in Section 3.1, some number of the withdrawn projects may have been later resubmitted, but the data did not clearly identify this. This finding highlights the importance of including project statuses with more granularity than “in-service” to better understand the project population.

Table 65. PG&E Non-NEM Full List of Project Statuses

PG&E Project Status	Count	Aggregate Capacity (MW)	% of Aggregate Capacity
Withdrawn	63	21.1	31.6%
In-service	62	5.3	7.9%
Implementation	33	32.4	48.6%
Study in progress	10	2.2	3.3%
IA in progress	4	4.8	7.2%
Application accepted	4	0.5	0.8%
Application review in progress	1	0.4	0.6%
Total	**177**	**66.7**	**100%**

Table 66 shows the number of SCE non-NEM projects identified over the 3-year study period. Unlike the combined NEM and non-NEM database extract received from PG&E, SCE and SDG&E provided separate files for NEM and non-NEM projects with different fields populated. For SCE, the non-NEM data included 1,028 projects (compared with over 134,000 NEM projects). Unlike the NEM data for SCE, the non-NEM data included populated fields for project type and project status. Table 66 shows that similar to PG&E, Non-Export was the most common non-NEM project type, representing 64.6% of records.

Table 66. SCE Non-NEM Project Count by Project Type

SCE Project Type	In-Service	Withdrawn	Other	Total
Rule 21 Non-Export	314	69	281	**664**
NEM-ST	10	29	104	**143**
NEM Aggregation	17	21	50	**88**
Rule 21 Export	3	25	42	**70**
NEM	5	2	6	**13**
Rule 21 Non-Export (No IA Req)	8	3	1	**12**
Other (Queued)	2	9	1	**12**
NEM-Military (SB-83)	2	3	5	**10**
NEM-MT-ST	-	-	5	**5**

SCE Project Type	In-Service	Withdrawn	Other	Total
NEM-ST Aggregation	-	1	4	**5**
NEM CDCR	-	-	3	**3**
QF Conversion	2		1	**3**
Total	**363**	**162**	**503**	**1,028**

Table 66 also shows a number of projects received in the SCE non-NEM dataset had NEM project types listed in the project type field such as NEM-ST and NEM Aggregation. Although this appears to be a discrepancy in classification, the research team assumed that utility staff properly categorized projects when providing separate data files for NEM and non-NEM projects. Therefore, the team did not reclassify any projects between the NEM and non-NEM categories. This discrepancy may be the result of projects requesting interconnection under a NEM program but later changing to a non-NEM program. To eliminate this uncertainty and confirm that records are properly categorized as NEM or non-NEM, the Commission should take steps to confirm that records that initially apply under one program type but change to a different type are appropriately identified and classified.

Table 67 shows project counts and aggregate capacity for the full list of SCE non-NEM project statuses. Projects with a status of in-service accounted for 31.2% of projects by count but only 13.4% of projects by aggregate capacity. If projects with the status in-service (conditional PTO) are added, these proportions increase to 35.1% by count and 20.5% by aggregate capacity. Withdrawn projects accounted for 15.8% of projects by count and 22.6% of projects by aggregate capacity. As with the PG&E data, some number of these withdrawn SCE non-NEM projects may have been resubmitted under a new record, but the data did not clearly identify whether or how often this occurred.

Most of the remaining project statuses reflected projects in various stages of the application, review, study, or implementation process. Among these, construction, pending PTO, and IA negotiation each comprised over 15% of records by both count and aggregate capacity.

Table 67. SCE Non-NEM Full List of Project Statuses

SCE Project Status	Count	Aggregate Capacity (MW)	% of Aggregate Capacity
In-service	321	132.5	13.4%
Construction	199	182.8	18.5%
Withdrawn	162	223.8	22.6%
Pending PTO	157	159.8	16.1%
IA negotiation	47	88.0	8.9%
Transferred to NEM	40	10.8	1.1%
In-service (conditional PTO)	40	69.9	7.1%
Transferred to WDAT	8	21.2	2.1%
Application review in progress	7	1.8	0.2%
IA terminated	7	4.3	0.4%
Fast track IR complete	6	5.3	0.5%
SIS in progress	4	26.7	2.7%

SCE Project Status	Count	Aggregate Capacity (MW)	% of Aggregate Capacity
SIS complete	4	11.9	1.2%
On hold	4	3.1	0.3%
Phase I in progress	3	9.0	0.9%
Application review complete	3	4.0	0.4%
Technical assessment in progress	2	10.8	1.1%
Transferred to Rule 21	2	0.2	0.02%
IA amendment	2	2.6	0.3%
In-service (transferred to NEM)	2	1.9	0.2%
Intake	2	0	0%
SR complete	1	1.7	0.2%
Combined SIS and FAC in progress	1	3.8	0.4%
IA parked	1	0	0%
Fast track IR in progress	1	0.3	0.03%
Technical assessment complete	1	10.0	1.0%
Restudy complete	1	4.0	0.4%
Total	**1,028**	**990.1**	**100%**

Table 68 shows the number of SDG&E non-NEM projects identified over the 3-year study period by project type. The research team identified 133 non-NEM projects compared with 71,303 NEM projects. As with the NEM data, the non-NEM data received from SDG&E included in-service projects only. The two most common project types were Export and Non-Export for Advanced Energy Storage. Advanced Energy Storage Export represented 44.4% of projects by count and 23.2% by capacity, while Advanced Energy Storage Non-Export represented 28.6% of projects by count and 10.7% by capacity.

Table 68. SDG&E Non-NEM Project Count by Project Type

SDG&E Project Type	Count	Aggregate Capacity (MW)	% of Aggregate Capacity
Rule 21 - Advanced Energy Storage Export	59	11.0	23.2%
Rule 21 - Advanced Energy Storage Non-Export	38	5.0	10.7%
NEM-2 Fuel Cell, after 1/01/17	17	10.0	21.2%
Rule 21 Export	8	8.9	18.8%
NEM-1 Fuel Cell, before 1/01/17	3	1.8	3.8%
Rule 21 Non-Export	2	6.7	14.1%
Rule 21 Inadvertent Export	2	0.1	0.2%
RES-BCT	1	0.6	1.2%
Non-NEM	1	1.9	4.1%
Standard NEM, after 6/29/16	1	1.1	2.3%

SDG&E Project Type	Count	Aggregate Capacity (MW)	% of Aggregate Capacity
Rule 21 - Advanced Energy Storage Inadvertent Export	1	0.2	0.3%
Total	**133**	**47.2**	**100%**

Similar to SCE, SDG&E provided separate NEM and non-NEM data files. In SDG&E's non-NEM file, a number of projects also had NEM project types listed including NEM-FC, RES-BCT, and Standard NEM. As was done for SCE, the research team assumed that utility staff properly categorized projects and did not reclassify any projects between the NEM and non-NEM categories. Future data tracking efforts should confirm that projects that change to a different program type are appropriately identified and classified.

The previous tables show inconsistencies in the specific project type and project status values reported for non-NEM records among the three utilities. The research team recognizes that utility treatment or classification of projects may differ—for example, SDG&E distinguishes between advanced energy storage and non-advanced energy storage non-NEM project types while the other utilities do not. To streamline project classification and promote consistency and comparability, reporting requirements should provide a list of allowed project type and project status values or provide guidelines to map varying utility-specific values to a common set of values.

4.1.2 Project Size Breakdown

Table 69 breaks down PG&E's non-NEM project applications by the four size buckets discussed in Section 2.3.1. The table includes all project statuses, including withdrawn projects. For each bucket, the table shows the number of projects as an absolute number and as a percentage of the total, the mean project size in kW, the total aggregate capacity in MW, and the percent contribution to the total aggregate capacity.

Table 69. PG&E Non-NEM Project Size and Capacity Breakdown

Size Bucket	PG&E Count	% of Count	Mean Project Size (kW)	Aggregate Capacity (MW)	% of Aggregate Capacity
Less than 30 kW	75	42.4%	12.2	0.9	1.4%
30-100 kW	25	14.1%	45.6	1.1	1.7%
100 kW-1 MW	61	34.5%	266.5	16.3	24.4%
1 MW or greater	16	9.0%	3,022.6	48.4	72.5%
Total	**177**	**100%**	**376.7**	**66.7**	**100%**

In general, the PG&E non-NEM project population consisted of larger projects than the NEM project population. In the non-NEM population, projects less than 30 kW comprised only 42.4% of projects as compared with almost 98% of NEM projects. The average NEM project size was 10.8 kW, while the average non-NEM project size was 376.7 kW. On an aggregate capacity basis, the 9.0% of non-NEM projects sized 1 MW or greater accounted for over 73% of aggregate capacity.

Table 70 shows the SCE non-NEM project size breakdown for all project statuses. The non-NEM project population for SCE was also skewed toward larger projects, with only 20.5% of projects representing 0.2% of capacity sized less than 30 kW. The 23.2% of projects sized at 1 MW or greater accounted for over 80% of total aggregate non-NEM capacity. SCE's mean non-NEM project size of 963 kW was the largest of the three utilities.

Table 70. SCE Non-NEM Project Size and Capacity Breakdown

Size Bucket	SCE Count	% of Count	Mean Project Size (kW)	Aggregate Capacity (MW)	% of Aggregate Capacity
Less than 30 kW	211	20.5%	10.8	2.3	0.2%
30-100 kW	148	14.4%	53.4	7.9	0.8%
100 kW-1 MW	431	41.9%	422.8	182.2	18.4%
1 MW or greater	238	23.2%	3,351.6	797.7	80.6%
Total	**1,028**	**100%**	**963.1**	**990.1**	**100%**

Table 71 shows the size breakdown of SDG&E non-NEM projects, which included in-service projects only. Compared with the NEM population in which 99% of projects were under 30 kW, only 24.1% of non-NEM projects were under 30 kW. The greatest number of projects (47.4%) were in the 100 kW-1 MW bucket and accounted for around half of aggregate installed capacity. The projects sized 1 MW or greater contributed a similar amount to aggregate capacity (45.8%) despite representing only 6.8% of projects by count.

Table 71. SDG&E Non-NEM Project Size and Capacity Breakdown

Size Bucket	SDG&E Count	% of Count	Mean Project Size (kW)	Aggregate Capacity (MW)	% of Aggregate Capacity
Less than 30 kW	32	24.1%	17.4	0.6	1.2%
30-100 kW	29	21.8%	52.4	1.5	3.2%
100 kW-1 MW	63	47.4%	373.3	23.5	49.8%
1 MW or greater	9	6.8%	2,398.9	21.6	45.8%
Total	**133**	**100%**	**354.7**	**47.2**	**100%**

4.1.3 Facility Technology Type Breakdown

As with the NEM populations, the research team segmented the non-NEM project populations by generation technology type, separating out solar and storage projects and in particular, identifying paired storage versus standalone storage. Again, this separation had varying success given the data structures.

Table 72 shows the PG&E non-NEM count of projects broken down by technology and project size. Similar to the utility's NEM population, the research team only identified a single technology type for each record. Therefore, all non-NEM projects that had a technology type of storage were initially classified as standalone storage. The data did not clearly indicate which storage projects, if any, were paired with existing onsite generation facilities of a different technology type. These projects were reclassified simply as storage because of the uncertainty as to how many were standalone versus paired.

Table 72. PG&E Non-NEM Count by Technology Type and Size

PG&E Technology Type	Less than 30 kW	30-100 kW	100 kW-1 MW	1 MW or greater	Total
Storage	68	17	46	-	**131**
Solar	6	6	5	2	**19**
Other	-	2	7	10	**19**
Unknown	1	-	3	4	**8**
Total	**75**	**25**	**61**	**16**	**177**

The 19 projects classified as other included the following technologies: engine (6), other (6), microturbine (3), turbine (2), and fuel cell (2). Eight projects did not have an entry in the technology type field and were classified as unknown.

Table 73 shows the same technology type breakdown for PG&E on an aggregate capacity basis rather than a per-project basis.

Table 73. PG&E Non-NEM Aggregate Capacity by Technology Type and Size

PG&E Technology Type	Less than 30 kW	30 to 100 kW	100 kW to 1 MW	1 MW or greater	Total
Storage	1.2%	1.0%	17.7%	-	**19.9%**
Solar	0.2%	0.5%	1.3%	30.8%	**33%**
Other	-	0.2%	4.0%	31.5%	**35.6%**
Unknown	0.004%	-	1.4%	10.3%	**11.7%**
Total	**1.4%**	**1.7%**	**24.4%**	**72.5%**	**100%**

Unlike the SCE NEM data and the data for the other utilities, the SCE non-NEM technology type field was populated in a format that allowed the research team to identify all technologies associated with a project. Each relevant technology type was also accompanied by an indication of the capacity of that technology in MW. For example, one entry in the SCE non-NEM technology type field was Photovoltaic(0.672)/Energy Storage(0.5)/Fuel Cell(1.05), indicating that three technologies with a total capacity of 2.222 MW were present. However, the total project capacity obtained by summing the capacity of each listed technology did not always match the capacity provided in the project size field. The research team used the value in the project size field rather than the sum of the individual technology capacities.

While it required additional effort to process the technology data for the SCE non-NEM records, the format did allow the team to identify many unique technology combinations. Table 74 shows the full list of technology types identified and their frequency.

Given the large number of unique combinations, the research team simplified them into solar, standalone storage, paired storage, other, or unknown categories to match the other utilities. Table 74 also shows the categories each technology combination was mapped to. The solar category includes projects for which the only technology type was photovoltaic, while standalone storage includes projects for which the only unique technology type was energy storage. Any remaining combination that included energy storage was mapped to paired storage regardless of the paired technology type. All remaining combinations that included at least one technology besides solar or storage were then mapped to other.

Table 74. SCE Non-NEM Full Technology Combination List

SCE Non-NEM Technology Combination	Count	Map
Storage	506	Standalone storage
Solar	281	Solar
Solar, storage	99	Paired storage
Unknown	30	Unknown
Internal combustion engine	27	Other
Fuel cell	8	Other
Wind	8	Other
Steam turbine	7	Other
Fuel cell, storage	7	Paired storage
Cogeneration	6	Other
Microturbine	6	Other
Combustion turbine	5	Other
Hydroelectric	5	Other
Fuel cell, solar, storage	5	Paired storage
Fuel cell, solar	4	Other
Internal combustion engine, solar	2	Other
Cogeneration, solar	2	Other
Fuel cell, microturbine, storage	2	Paired storage
Cogeneration, storage	2	Paired storage
Gas turbine	2	Other
Solar, wind	2	Other
Cogeneration, solar, storage	2	Paired storage
Dynamometer	1	Other
Gas turbine, solar	1	Other
Internal combustion engine, storage	1	Paired storage
Cogeneration, microturbine	1	Other
Engine, solar, storage	1	Paired storage
Internal combustion engine, microturbine	1	Other
Microturbine, solar, storage	1	Paired storage
Engine, solar	1	Other
Combustion turbine, storage	1	Paired storage
Solar, storage, wind	1	Paired storage
Total	**1,028**	**-**

Table 75 presents the SCE non-NEM project breakdown by technology using these simplified technology categories. Standalone storage (49.2% of projects) was the most common non-NEM technology type, followed by standalone solar (29.3%) and paired storage (11.9%).

Table 75. SCE Non-NEM Project Count by Technology Type and Size

SCE Technology Type	Less than 30 kW	30-100 kW	100 kW-1 MW	1 MW or greater	Total
Standalone storage	100	112	253	41	**506**
Paired storage	35	10	38	39	**122**
Solar	58	18	110	95	**281**
Other	5	7	17	60	**89**
Unknown	13	1	13	3	**30**
Total	**211**	**148**	**431**	**238**	**1,028**

Table 76 shows the same non-NEM technology type breakdown for SCE on an aggregate capacity basis rather than a per-project basis.

Table 76. SCE Non-NEM Aggregate Capacity by Technology Type and Size

SCE Technology Type	Less than 30 kW	30-100 kW	100 kW-1 MW	1 MW or greater	Total
Standalone Storage	0.1%	0.6%	9.2%	10.2%	**20.1%**
Paired Storage	0.08%	0.05%	1.8%	12.6%	**14.6%**
Solar Only	0.01%	0.1%	6.0%	26.5%	**32.7%**
Other	0.007%	0.05%	0.7%	30.5%	**31.2%**
Unknown	-	0.008%	0.6%	0.8%	**1.4%**
Total	**0.2%**	**0.8%**	**18.4%**	**80.6%**	**100%**

Table 77 shows the SDG&E non-NEM technology type breakdown. In the non-NEM data file, each record had only one entry in the technology type field. Only four unique technologies were listed: solar, advanced energy storage, fuel cell – natural gas, and internal combustion engine. As with other datasets, the data did not indicate if the records truly included only one technology type or if the listed technology was paired with other facilities. Because there was no clear indication if the storage records were paired or standalone, the research team classified all projects with the advanced energy storage as simply storage.

Table 77. SDG&E Non-NEM Project Count by Technology Type and Size

SDG&E Technology Type	Less than 30 kW	30-100 kW	100 kW-1 MW	1 MW or greater	Total
Storage	32	27	41	1	**101**
Other	-	2	20	6	**28**
Solar	-	-	2	2	**4**
Total	**32**	**29**	**63**	**9**	**133**

The 28 non-NEM projects categorized as other consisted of 20 fuel cell projects and eight internal combustion engine projects.

Table 78 shows the SDG&E non-NEM technology type breakdown on an aggregate capacity basis rather than a per-project basis.

Table 78. SDG&E Non-NEM Aggregate Capacity by Technology Type and Size

SDG&E Technology Type	Less than 30 kW	30-100 kW	100 kW-1 MW	1 MW or greater	Total
Storage	1.2%	3.1%	28.1%	2.1%	**34.5%**
Other	-	0.2%	20.1%	37.3%	**57.6%**
Solar	-	-	1.6%	6.3%	**8.0%**
Total	**1.2%**	**3.2%**	**49.8%**	**45.8%**	**100%**

The research team faced similar challenges in identifying technology types in the non-NEM data as in the NEM data and reiterates the following recommendations for future data tracking and reporting requirements. Specifically, future data tracking and reporting requirements should:

- Confirm all reported projects have a listed generation technology type to avoid classifications of unknown.
- Provide flexibility for reporting multiple technology types when an interconnecting project consists of multiple technologies or when the interconnecting project is an addition to an already-existing facility. The non-NEM data from SCE did achieve this, though there were discrepancies in the project capacity values.
- Clearly distinguish between paired storage and standalone storage.

4.1.4 Rule 21 Reviews and Studies Performed

This section presents the results of the analysis outlined in Section 2.3.1, which identified the specific reviews and studies that each non-NEM project underwent. As discussed, this required analyzing all relevant timeline data for a given project and using the presence of data in fields related to a specific study to indicate that study occurred for a given project.

Table 79 breaks down the reviews and studies found for PG&E’s non-NEM projects. IR only was the most common identified combination—found for about two-thirds of projects. Only one project had data clearly indicating that SIS was performed, and the remaining projects had IR and SR.

Table 79. PG&E Non-NEM Reviews and Studies Count by Project Size

PG&E Reviews/ Studies Performed	Less than 30 kW	30-100 kW	100 kW-1 MW	1 MW or greater	Total
IR	57	20	34	9	**120**
IR, SR	1	2	4	4	**11**
SIS	-	-	-	1	**1**
Could not determine	17	3	23	2	**45**
Total	**75**	**25**	**61**	**16**	**177**

The specific reviews and studies performed could not be determined for 45 projects. Most (36) of these projects had a status of withdrawn. The remaining statuses were application accepted (4), study in progress (3), application review in progress (1), and in-service (1). All of these projects categorized as could not determine had a value of fast track in the study process field. However, none of these projects had data in any of the timeline fields for IR or SR to indicate which fast track reviews, if any, were actually completed.

Table 80 presents the number of reviews and studies for PG&E non-NEM projects broken down by generation technology type rather than project size. This data shows that among the projects with clear data, SR and SIS only occurred for non-solar projects.

Table 80. PG&E Non-NEM Reviews and Studies Count by Technology Type

PG&E Reviews/ Studies Performed	Storage	Solar	Other	Unknown	Total
IR	94	15	5	6	120
IR, SR	6	-	4	1	11
SIS	-	-	1	-	1
Could not determine	31	4	9	1	45
Total	**131**	**19**	**19**	**8**	**177**

Table 81 breaks down the reviews and studies found for SCE non-NEM records. Data indicated that around 80% of projects underwent IR only, around 12% underwent SR, and less than 2% underwent SIS.

Table 81. SCE Non-NEM Reviews and Studies Count by Project Size

SCE Reviews/ Studies Performed	Less than 30 kW	30-100 kW	100 kW-1 MW	1 MW or greater	Total
IR	204	147	370	111	**832**
IR, SR	5	1	53	65	**124**
IR, SIS	-	-	-	15	**15**
IR, SR, SIS	1	-	-	-	**1**
IR, SR, SIS, FS	-	-	-	1	**1**
Could not determine	1	-	8	46	**55**
Total	**211**	**148**	**431**	**238**	**1,028**

The reviews or studies performed could not be determined for 55 projects. Of these, the study process track field was fast track for seven, detailed study for 13, ISP for 31, and DGS for one. However, these projects were not classified because there was no data in any timeline field related to any particular study. For example, although 31 of these projects were marked as ISP, none had data in the timeline fields related to SIS or FS and were therefore marked as could not determine.

Table 82 shows the review and study breakdown of SCE non-NEM projects by technology rather than size. The table shows that SR and SIS were not limited to any particular technology type.

Table 82. SCE Non-NEM Reviews and Studies Count by Technology Type

SCE Reviews/ Studies Performed	Storage	Solar	Other	Unknown	Total
IR	588	170	51	23	**832**
IR, SR	24	78	18	4	**124**
IR, SIS	2	9	4	-	**15**
IR, SR, SIS	-	-	-	1	**1**
IR, SR, SIS, FS	-	1	-	-	**1**
Could not determine	14	22	17	2	**55**
Total	**628**	**280**	**90**	**30**	**1,028**

Table 83 shows the breakdown of reviews and studies performed for SDG&E's non-NEM projects. All but one project underwent IR only. Interconnection staff at SDG&E confirmed in follow-up discussions that no non-NEM (or NEM) projects in the study period underwent SR or FS and that only two projects underwent SIS. However, one of these SIS projects was removed from the dataset during the data cleaning and processing phase because the project PTO date occurred several months after the end of the 3-year study window. The one remaining project that underwent SIS in addition to IR was a fuel cell project in the 1 MW or greater size bucket.

Table 83. SDG&E Non-NEM Reviews and Studies Count

SDG&E Reviews/ Studies Performed	Count
IR	132
IR, SIS	1
Total	**133**

For future data and reporting requirements, the research team provides similar recommendations to those noted in the NEM section (Section 3.1.4) to improve the identification of the reviews and studies performed for each project. These fields should be provided in an accessible format and should be required for every project as binary (true/false) values. This requirement would streamline the segmentation of the population and eliminate the need to review each timeline field separately.

4.2 Non-NEM Timelines: Key Tariff Steps

This section presents non-NEM results for the timeline analysis of key tariff steps described in Section 2.3.2.2. The results for each step are presented for each utility and broken down by project size and technology where applicable.

4.2.1 Non-NEM Time to Validate Application

As discussed in Section 3.2.2, the research team calculated the time to validate the interconnection application as the number of BD between application submittal and date application deemed complete. The team did not perform the analysis for any project missing either of these dates. If an application does not have any deficiencies, this step should take no more than 10 BD. If an application has deficiencies, Rule 21 provides additional time to resolve them (as discussed in Section 4.2.2).

Table 84 shows the PG&E non-NEM results for time to validate the application. The overall mean time was 18.6 BD, and 17.4% projects were validated in 10 BD or less. The findings were relatively consistent across project sizes and technology types, suggesting that most non-NEM projects have application deficiencies that require additional time to resolve.

Table 84. PG&E Non-NEM Time to Validate Application

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 10 BD
By Project Size				
Less than 30 kW	62	21.3	27.1	17.7%
30-100 kW	23	15.0	7.1	8.7%
100 kW-1 MW	45	17.0	7.5	24.4%
1 MW or greater	14	17.5	4.6	7.1%
By Project Technology Type				
Solar	107	17.3	7.1	13.1%
Storage	15	27.2	54.8	14.3%
Other	14	18.3	5.2	12.5%
Unknown	8	19.4	7.4	53.3%
Total	**144**	**18.6**	**18.6**	**17.4%**

Table 85 shows the SCE non-NEM results for time to validate the application. The overall mean time was 30.2 BD, and 25.0% of projects were validated in 10 BD or less. As with PG&E, the results were similar across project size and technology categories.

Table 85. SCE Non-NEM Time to Validate Application

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 10 BD
By Project Size				
Less than 30 kW	175	21.7	26.7	35.4%
30-100 kW	137	18.4	17.2	29.9%
100 kW-1 MW	391	24.1	25.0	27.1%
1 MW or greater	208	42.3	41.4	9.1%
By Project Technology Type				
Standalone Storage	488	21.6	21.6	25.2%
Paired Storage	114	34.5	39.5	21.1%
Solar	215	32.7	40.0	30.2%
Other	74	33.0	22.4	16.2%
Unknown	20	28.4	30.0	20.0%
Total	**911**	**26.9**	**30.2**	**25.0%**

Table 86 shows the SDG&E non-NEM results for time to validate the application. The mean time was 7.2 BD, and 82.7% of projects were validated in 10 BD or less. As with its NEM results for this step, performance was relatively consistent across the project size and technology categories. These results suggest that application deficiencies are either uncommon or quickly resolved when they occur with SDG&E.

Table 86. SDG&E Non-NEM Time to Validate Application

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 10 BD
By Project Size				
Less than 30 kW	32	7.0	9.3	87.5%
30-100 kW	29	8.7	21.4	86.2%
100 kW-1 MW	63	7.2	7.6	77.8%
1 MW or greater	9	3.2	3.8	88.9%
By Project Technology Type				
Storage	101	6.0	7.6	88.1%
Other	28	11.6	21.8	64.3%
Solar	4	7.0	7.3	75.0%
Total	**133**	**7.2**	**12.1**	**82.7%**

4.2.2 Non-NEM Time to Resolve Application Deficiencies

As discussed in Section 3.2.3, the research team assessed the steps related to resolving application deficiencies in two groups: a group with the steps for deficiency notifications by the utility and another with the steps for customer responses.

Table 87 and Table 88 show the PG&E non-NEM results for the utility time to provide deficiency notifications and the customer time to respond to notifications, respectively. The utility notification step was met 98.4% of the time with a mean of 4.1 BD, while the customer response time was met 49.0% of the time with a mean of 12.0 BD. Values were consistent across project size and technology categories for the utility notification step but not for the customer response step. Prior to drawing a conclusion on the relative performance of utility and applicant steps in future assessments, the Commission should require the utilities to confirm the dates recorded for customer responses reflect the date the customer sent the response rather than the date the response was processed or acknowledged.

Table 87. PG&E Non-NEM Time to Provide Notification of Application Deficiencies

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 10 BD
By Project Size				
Less than 30 kW	132	4.0	1.8	99.2%
30-100 kW	48	4.8	4.0	97.9%
100 kW-1 MW	103	3.7	2.1	99.0%
1 MW or greater	28	4.5	2.7	92.9%
By Project Technology Type				
Solar	236	4.0	1.9	99.2%
Storage	31	4.3	5.1	96.8%
Other	28	4.2	2.4	96.4%
Unknown	16	4.9	2.3	93.8%
Total	**311**	**4.1**	**2.4**	**98.4%**

Table 88. PG&E Non-NEM Time to Respond to Notification of Application Deficiencies

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 10 BD
By Project Size				
Less than 30 kW	61	15.4	27.7	39.3%
30-100 kW	23	6.7	5.9	78.3%
100 kW-1 MW	45	10.5	7.3	46.7%
1 MW or greater	14	10.4	4.8	50.0%
By Project Technology Type				
Solar	108	10.7	6.6	48.1%
Storage	14	22.3	58.1	71.4%
Other	13	11.4	5.6	30.8%
Unknown	8	11.5	6.9	50.0%
Total	**143**	**12.0**	**18.9**	**49.0%**

Table 89 and Table 90 show the SCE non-NEM results for utility application deficiencies and customer responses, respectively. The tables show similar results—55.7% adherence and a mean of 12.8 BD for the utility notification steps and 58.5% adherence and a mean of 12.3 BD for the customer response steps. Results across the project size and technology categories do not show clear trends.

Table 89. SCE Non-NEM Time to Provide Notification of Application Deficiencies

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 10 BD
By Project Size				
Less than 30 kW	24	15.9	28.7	62.5%
30-100 kW	2	10.5	0.7	50.0%
100 kW-1 MW	63	11.8	10.3	55.6%
1 MW or greater	33	12.5	12.5	51.5%
By Project Technology Type				
Standalone Storage	65	12.6	12.4	53.8%
Paired Storage	26	9.0	5.1	69.2%
Solar	18	19.8	32.9	50.0%
Other	13	11.6	7.1	46.2%
Total	**122**	**12.8**	**16.0**	**55.7%**

Table 90. SCE Non-NEM Time to Respond to Notification of Application Deficiencies

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 10 BD
By Project Size				
Less than 30 kW	12	13.0	4.2	33.3%
30-100 kW	1	14.0	-	0%
100 kW-1 MW	35	12.9	24.5	62.9%
1 MW or greater	17	10.4	10.2	70.6%
By Project Technology Type				
Standalone Storage	35	9.8	7.8	57.1%
Paired Storage	15	8.9	8.1	73.3%
Solar	9	27.0	45.0	33.3%
Other	6	13.2	12.3	66.7%
Total	**65**	**12.3**	**18.7**	**58.5%**

The SDG&E non-NEM data did not include fields for deficiency notification dates or response dates, so the research team did not perform this analysis. The results from Table 86 suggest that deficiencies were not a significant cause of delays for SDG&E non-NEM projects. As with the NEM analysis, the team used sampled qualitative data from SCE and SDG&E to identify common application deficiencies and other flagged issues, which are detailed as follows.

- For SCE, the most common application deficiencies and flagged issues included mismatched information between the application and single-line diagram, missing inverter information, and missing plot plans.

- For SDG&E, the most common deficiencies and flagged issues included missing drawings or equipment information, missing certificates of insurance, and waiting for payment of fees.

4.2.3 Non-NEM Time to Complete IR

The research team calculated the time to complete IR as the time between the date application deemed complete and the date initial review results provided to the customer fields. Table 91 shows the PG&E non-NEM results for time to complete IR. Overall, only 34.4% of projects met the 15 BD requirement. Performance was higher than the average for projects in the less than 30 kW, solar, and storage categories but lower than the average for the other categories.

Table 91. PG&E Non-NEM Time to Complete IR

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 15 BD
By Project Size				
Less than 30 kW	58	23.3	26.4	53.4%
30-100 kW	22	44.7	30.1	9.1%
100 kW-1 MW	38	30.8	26.3	23.7%
1 MW or greater	13	49.4	38.6	23.1%
By Project Technology Type				
Solar	100	29.7	26.2	33.0%
Storage	15	34.9	38.8	33.3%
Other	9	41.0	42.6	44.4%
Unknown	7	41.1	37.3	42.9%
Total	**131**	**31.7**	**29.6**	**34.4%**

Table 92 shows the SCE non-NEM results for time to complete IR. Overall, 43.1% of projects met the requirement. The adherence rate for all size and technology categories ranged between 25% and 50%.

Table 92. SCE Non-NEM Time to Complete IR

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 15 BD
By Project Size				
Less than 30 kW	131	14.8	30.0	50.4%
30-100 kW	119	17.3	16.8	41.2%
100 kW-1 MW	315	14.1	24.8	44.8%
1 MW or greater	120	21.6	33.1	32.5%
By Project Technology Type				
Standalone Storage	397	13.6	21.1	47.1%
Paired Storage	92	19.0	37.5	34.8%
Solar	143	20.1	33.3	42.7%

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 15 BD
Other	41	17.4	7.2	26.8%
Unknown	12	24.9	28.9	33.3%
Total	**685**	**16.1**	**26.5**	**43.1%**

Table 93 shows the SDG&E non-NEM results for time to complete IR. Overall, 77.3% of projects met the 15 BD requirement. The adherence rate was especially high for projects less than 100 kW but did not vary considerably by technology type.

Table 93. SDG&E Non-NEM Time to Complete IR

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 15 BD
By Project Size				
Less than 30 kW	32	7.0	9.2	84.4%
30-100 kW	29	8.2	5.0	93.1%
100 kW-1 MW	62	13.6	12.2	66.1%
1 MW or greater	9	14.0	6.4	77.8%
By Project Technology Type				
Storage	100	11.1	10.7	78.0%
Other	28	10.5	9.4	75.0%
Solar	4	7.3	5.9	75.0%
Total	**132**	**10.8**	**10.3**	**77.3%**

4.2.4 Non-NEM Time to Complete SR

The research team assessed the time to complete SR using an assumed 30 BD requirement between IR completion and SR completion assuming no IR results meeting; these 30 BD consist of 10 BD for the customer to choose to move on to SR and 20 BD for the utility to complete SR and notify the customer of the results.

Table 94 shows the PG&E non-NEM results for time to complete SR. The overall adherence rate was 27.3% with a mean of 42.2 BD, though the population size was only 11 projects. Performance was better for the smaller size categories than the larger size categories.

Table 94. PG&E Non-NEM Time to Complete SR after IR

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 30 BD
By Project Size				
Less than 30 kW	1	1.0	-	100%
30-100 kW	2	35.0	11.3	50.0%
100 kW-1 MW	4	50.8	23.8	25.0%

1 MW or greater	4	47.5	8.3	0%
By Project Technology Type				
Storage	6	36.7	26.8	50.0%
Other	4	47.5	8.3	0%
Unknown	1	54.0	-	0%
Total	**11**	**42.2**	**20.6**	**27.3%**

Table 95 shows the SCE non-NEM results for time to complete SR. The overall adherence rate was 50.0% with a mean of 32.5 BD. SR occurred much more frequently for projects greater than 100 kW than for projects smaller than 100 kW. Performance was better for projects sized less than 1 MW than those greater than 1 MW.

Table 95. SCE Non-NEM Time to Complete SR after IR

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 30 BD
By Project Size				
Less than 30 kW	5	52.6	39.4	40.0%
30-100 kW	1	46.0	-	0%
100 kW-1 MW	48	19.7	39.3	72.9%
1 MW or greater	54	41.7	20.7	31.5%
By Project Technology Type				
Standalone Storage	10	38.2	17.3	30.0%
Paired Storage	10	45.1	16.8	20.0%
Solar	69	29.5	38.1	55.1%
Other	14	31.5	13.9	50.0%
Unknown	5	39.8	41.5	80.0%
Total	**108**	**32.5**	**33.0**	**50.0%**

The time to complete SR analysis was not applicable to the SDG&E non-NEM dataset because no projects underwent SR.

4.2.5 Non-NEM Time to Complete SIS

As Table 14 shows, the research team performed two assessments for the time to complete SIS, using either the DSA execution date or the date of IR or SR completion as applicable. The PG&E non-NEM population contained only one project for which completion of SIS could be confirmed (see Table 79). For this project—an engine project greater than 1 MW—the time between DSA execution and SIS completion was 44 BD. Because this project did not undergo IR or SR, the second assessment using date of IR or SR completion was not applicable.

Table 96 shows the SCE non-NEM results for time to complete SIS after IR or SR. The overall adherence rate was 93.3% with a mean of 82.5 BD. Every project the research team analyzed was sized at 1 MW or greater. That the mean is much less than the team's calculated requirement of 145 or 150 BD suggests that the steps for detailed study screens, scoping meetings, and DSA execution were completed well within the allowed time.

Table 96. SCE Non-NEM Time to Complete SIS

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 150 BD
By Project Size				
1 MW or greater	15	82.5	60.6	93.3%
By Project Technology Type				
Solar	10	101.3	66.6	90.0%
Paired Storage	1	24.0	-	100%
Other	4	50.3	11.5	100%
Total	**15**	**82.5**	**60.6**	**93.3%**

* Time requirement is 150 BD after IR but 145 BD after SR.

The time to complete SIS step was relevant only to the one SDG&E non-NEM project that underwent SIS (see Table 83), a fuel cell project sized greater than 1 MW. SIS for this project was completed 50 BD after IR completion.

4.2.6 Non-NEM Time to Send GIA to Customer

The research time assessed the steps associated with the utility sending a draft GIA to the customer upon completion of IR, SR, or SIS. Table 97 shows the PG&E non-NEM results for time to send a draft GIA to the customer after completing IR or SR. Overall, 76.2% of the projects met the 15 BD requirement with a mean time of 14.3 BD. The time to send a draft GIA to the customer after completing SIS was relevant to the single PG&E non-NEM project that completed SIS (see Table 80). The step was completed in 10 BD—well under the requirement of 30 CD plus 25 BD.

Table 97. PG&E Non-NEM Time to Send GIA to Customer after IR or SR

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 15 BD
By Project Size				
Less than 30 kW	39	16.2	22.2	71.8%
30-100 kW	21	2.0	3.0	100%
100 kW-1 MW	29	13.9	21.6	69.0%
1 MW or greater	12	30.7	63.4	66.7%
By Project Technology Type				
Solar	76	12.0	20.2	78.9%
Storage	14	12.6	18.3	71.4%
Other	6	51.0	87.6	80.0%
Unknown	5	10.8	14.3	50.0%
Total	**101**	**14.3**	**28.7**	**76.2%**

Table 98 shows the SCE non-NEM results for the time to send a draft GIA after completing IR or SR. The mean result was 21.6 BD across all assessed records, and the adherence rate to the

15 BD requirement was only 45.2%. The rate was especially low for projects sized 1 MW or greater and technology types other than standalone storage.

Table 98. SCE Non-NEM Time to Send GIA to Customer after IR or SR

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 15 BD
By Project Size				
Less than 30 kW	68	22.2	39.2	38.2%
30-100 kW	96	17.8	27.3	54.2%
100 kW-1 MW	203	20.2	35.6	48.8%
1 MW or greater	36	38.6	35.8	13.9%
By Project Technology Type				
Standalone Storage	311	15.8	26.9	53.1%
Paired Storage	55	39.2	56.2	21.8%
Solar	28	47.9	37.5	10.7%
Other	9	34.0	25.4	22.2%
Total	**403**	**21.6**	**34.8**	**45.2%**

Table 99 shows the SCE non-NEM results for the time to send a draft GIA after completing SIS. All eight projects assessed for this step met the tariff requirement of 30 BD plus 25 BD; the mean time was 26.6 BD.

Table 99. SCE Non-NEM Time to Send GIA to Customer after SIS

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 30 CD + 25 BD
By Project Size				
1 MW or greater	8	26.6	9.2	100%
By Project Technology Type				
Solar	7	27.1	9.8	100%
Paired Storage	1	23.0	-	100%
Total	**8**	**26.6**	**9.2**	**100%**

Table 100 shows the SDG&E non-NEM results for the time to send a draft GIA to the customer after completing IR. No projects completed SR. The overall adherence rate of 96.9% was driven by projects less than 1 MW, which have negative mean values; these values indicate that some form of GIA execution occurred prior to IR completion for many of these projects. This was not the case for projects sized 1 MW or greater.

Table 100. SDG&E Non-NEM Time to Send GIA to Customer after IR

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 15 BD
By Project Size				

Less than 30 kW	32	-17.2	31.3	100%
30-100 kW	29	-0.5	67.2	96.6%
100 kW-1 MW	58	-33.9	59.5	98.3%
1 MW or greater	8	55.6	178.0	75.0%
By Project Technology Type				
Storage	100	-23.3	42.6	100%
Other	23	19.8	135.1	87.0%
Solar	4	-52.8	93.1	75.0%
Total	**127**	**-16.4**	**71.7**	**96.9%**

Only one SDG&E non-NEM completed SIS, a fuel cell project greater than 1 MW. The time between SIS completion and sending a draft GIA to the customer was 24 BD, which is less than the requirement of 30 CD plus 25 BD.

4.2.7 Non-NEM Time for Customer to Execute GIA

The research team used the date draft GIA sent to customer and date executed GIA returned by customer fields to assess the 90 CD requirement for customer execution of the GIA. Table 101 shows that the mean time was 46.6 CD and the 90 CD adherence rate was 84.1% for PG&E non-NEM projects.

Table 101. PG&E Non-NEM Time for Customer to Execute GIA

Category	Count	Mean (CD)	Std. Dev. (CD)	Percent ≤ 90 CD
By Project Size				
Less than 30 kW	34	26.6	34.8	91.2%
30-100 kW	18	62.1	34.2	72.2%
100 kW-1 MW	23	64.0	68.1	82.6%
1 MW or greater	7	47.0	26.7	85.7%
By Project Technology Type				
Solar	62	43.6	37.6	83.9%
Storage	13	68.2	88.8	76.9%
Other	3	34.7	7.4	100%
Unknown	4	31.5	27.5	100%
Total	**82**	**46.6**	**48.6**	**84.1%**

Table 102 shows the SCE non-NEM mean time was higher at 64.0 CD, but the 90 CD adherence rate was similar to PG&E at 80.6%.

Table 102. SCE Non-NEM Time for Customer to Execute GIA

Category	Count	Mean (CD)	Std. Dev. (CD)	Percent ≤ 90 CD
By Project Size				

Less than 30 kW	64	49.4	44.3	89.1%
30-100 kW	95	55.5	43.8	85.3%
100 kW-1 MW	202	66.5	63.8	78.2%
1 MW or greater	47	90.1	112.6	70.2%
By Project Technology Type				
Standalone Storage	303	59.6	53.3	81.2%
Paired Storage	59	57.9	68.0	88.1%
Solar	32	90.1	92.7	71.9%
Other	14	124.5	148.5	57.1%
Total	**408**	**64.0**	**65.8**	**80.6%**

Table 103 shows the SDG&E non-NEM adherence rate for the time to execute the draft GIA by the customer was only 38.8%. The mean time of 117.8 CD exceeded the allowed time of 90 CD.

Table 103. SDG&E Non-NEM Time for Customer to Execute GIA

Category	Count	Mean (CD)	Std. Dev. (CD)	Percent ≤ 90 CD
By Project Size				
Less than 30 kW	32	124.8	80.9	34.4%
30-100 kW	29	121.9	79.5	31.0%
100 kW-1 MW	59	115.4	103.7	40.7%
1 MW or greater	9	95.8	82.1	66.7%
By Project Technology Type				
Storage	101	131.0	88.4	26.7%
Other	24	57.3	71.9	87.5%
Solar	4	147.0	135.1	50.0%
Total	**129**	**117.8**	**91.2**	**38.8%**

4.3 Non-NEM Total Time for Interconnection

As discussed in Section 2.3.2.3, the research team assessed the total time for interconnection from application submittal to GIA or PTO for each project based on the reviews or studies performed to provide a more complete picture of the total time a project took to complete the interconnection process. This section presents the results of this analysis for non-NEM projects.

Table 104 shows the PG&E non-NEM results for total time for interconnection from application to GIA or PTO. Most PG&E records did not have data in the GIA execution date field, so the PTO date was used when needed. The mean total time was 99.4 BD for all projects, but the mean varied widely based on the track. Overall, 63.6% of projects met the partial max requirement, while 94.9% met the full max requirement.

Table 104. PG&E Non-NEM Total Time to GIA or PTO Full Results

Track	Count	Mean (BD)	% Meeting Partial Max	% Meeting Full Max
All Projects				
IR	111	95.0	63.1%	94.6%
IR, SR	6	161.7	66.7%	100%
SIS	1	205.0	100%	100%
Total	**118**	**99.4**	**63.6%**	**94.9%**

Table 105 and Table 106 show results for the subset of 100 kW or greater projects and non-solar projects, respectively. The partial max and full max adherence rates for these subsets were consistent with the rates for the full population, suggesting that PG&E non-NEM projects requiring the same reviews or studies tend to complete the interconnection process in a similar amount of time regardless of size or technology type.

Table 105. PG&E Non-NEM Total Time to GIA or PTO Results for 100 kW-Plus Projects

Track	Count	Mean (BD)	% Meeting Partial Max	% Meeting Full Max
Projects Sized 100 kW or greater				
IR	38	97.4	68.4%	94.7%
IR, SR	4	173.0	75.0%	100%
SIS	1	205.0	100%	100%
Total	**43**	**107.0**	**69.8%**	**95.3%**

Table 106. PG&E Non-NEM Total Time to GIA or PTO Results for Non-Solar Projects

Track	Count	Mean (BD)	% Meeting Partial Max	% Meeting Full Max
Non-Solar Projects				
IR	96	88.4	63.5%	97.9%
IR, SR	6	161.7	66.7%	100%
SIS	1	205.0	100%	100%
Total	**103**	**93.8**	**64.1%**	**98.1%**

Table 107 shows the SCE non-NEM results for the total time for interconnection. The research team performed the analysis for 692 records; of these records, 677 had data for date of GIA execution and 15 did not, so the PTO date was used instead. The table shows an overall mean time of 112.7 BD for the total interconnection time, but this varied widely depending on the track. The overall adherence rates were 60.5% to the partial max and 88.7% to the total max requirements. The IR, SR track had a lower adherence rate than the IR-only track or tracks with SIS.

Table 107. SCE Non-NEM Total Time to GIA or PTO Full Results

Track	Count	Mean (BD)	% Meeting Partial Max	% Meeting Full Max
All Projects				
IR	610	114.2	62.5%	90.0%
IR, SR	77	181.9	42.9%	77.9%
IR, SIS	4	226.5	100%	100%
IR, SR, SIS, FS	1	364.0	100%	100%
Total	**692**	**122.7**	**60.5%**	**88.7%**

Table 108 and Table 109 show results for the subset of projects greater than 100 kW and the subset of non-solar projects, respectively. Results for these subsets were also relatively consistent with the full population, suggesting that the total time from application to GIA execution or PTO varies considerably depending on the track but not on the project size or technology.

Table 108. SCE Non-NEM Total Time to GIA or PTO Results for 100 kW-Plus Projects

Track	Count	Mean (BD)	% Meeting Partial Max	% Meeting Full Max
Projects Sized 100 kW or greater				
IR	362	126.6	56.1%	88.1%
IR, SR	75	184.6	41.3%	77.3%
IR, SIS	4	226.5	100%	100%
IR, SR, SIS, FS	1	364.0	100%	100%
Total	**442**	**137.9**	**54.1%**	**86.4%**

Table 109. SCE Non-NEM Total Time to GIA or PTO Results for Non-Solar Projects

Track	Count	Mean (BD)	% Meeting Partial Max	% Meeting Full Max
Non-Solar Projects				
IR	541	111.9	63.4%	90.6%
IR, SR	29	179.3	48.3%	79.3%
IR, SIS	1	222.0	100%	100%
Total	**571**	**115.5**	**62.7%**	**90.0%**

Table 110 shows the SDG&E non-NEM results for the total time for interconnection. All but one project was in the IR-only track. These projects reached GIA execution after a mean 91.7 BD and had an adherence rate of 68.9% for the partial max and 90.9% for the full max requirement. The one project in the IR, SIS track met both the partial max and full max requirements.

Table 110. SDG&E Non-NEM Total Time to GIA or PTO Full Results

Track	Count	Mean (BD)	% Meeting Partial Max	% Meeting Full Max
All Projects				
IR	132	91.7	68.9%	90.9%
IR, SIS	1	116.0	100%	100%
Total	**133**	**91.9**	**69.2%**	**91.0%**

Table 111 shows results for the subset of 100 kW-plus SDG&E non-NEM projects. The mean time and the adherence rates for the IR-only track improved for this subset of larger projects compared to the full population.

Table 111. SDG&E Non-NEM Total Time to GIA or PTO Results for 100 kW-Plus Projects

Track	Count	Mean (BD)	% Meeting Partial Max	% Meeting Full Max
Projects Sized 100 kW or greater				
IR	71	87.3	76.1%	94.4%
IR, SIS	1	116.0	100%	100%
Total	**72**	**87.7**	**76.4%**	**94.4%**

All but four of the 133 SDG&E non-NEM projects were non-solar technology types (see Table 77). The research team did not find significant variation in the partial max or full max adherence rate across the non-NEM technology type categories.

4.4 Summary of Non-NEM Findings and Recommendations

The research team analyzed the quantitative data for non-NEM projects to characterize the project population for each utility and assess timeline performance. This section summarizes key findings and recommendations for improving data collection and timeline performance.

4.4.1 Project Population Characterization and Segmentation

The research team summarized the non-NEM population for each utility based on the project type, project size, technology type, and Rule 21 reviews or studies performed. Overall, there were far fewer non-NEM projects than NEM projects. The following bullets outline key findings and recommendations related to the population segmentation.

Non-NEM Project Types

Key findings related to segmentation by non-NEM project type include the following.

- There were differences in the project type values reported for non-NEM records among the three utilities. This makes sense as the treatment or classification of projects differs by utility. For example, SDG&E distinguishes between advanced energy storage and non-advanced energy storage non-NEM project types while the other utilities do not.

- For PG&E, the research team categorized the non-export, continuous uncompensated export, and export project types as non-NEM. SCE and SDG&E provided non-NEM datasets with NEM project types listed in the project type field for some projects. The research team assumed that utility staff properly categorized projects when providing separate data files and did not reclassify any projects between the NEM and non-NEM categories.
- For PG&E and SCE, most non-NEM projects were non-export. For SDG&E, the majority of non-NEM project types were advanced energy storage export and advanced energy storage non-export.

Recommendations for improving data reporting to allow for the identification, segmentation, and comparison of project populations by non-NEM project type include the following.

- Data requirements should confirm that records are properly categorized as NEM or non-NEM. If the apparent discrepancy in classification for SCE and SDG&E was the result of projects requesting interconnection under a NEM program but later changing to a non-NEM program, then the Commission should take steps to confirm that records that initially apply under one program type but change to a different type are appropriately identified and classified.
- Requirements should promote consistency in the project types that are classified as non-NEM. To account for differences between the utilities, the requirements could include a list of allowed project type values or provide guidelines to map varying utility-specific values to a common set of values.

Non-NEM Project Statuses

Key findings for the segmentation by non-NEM project status include the following.

- PG&E and SCE data included all project statuses while SDG&E data included only in-service projects. The omission of other non-NEM project statuses from SDG&E limits this study.
- For PG&E, withdrawn projects accounted for a much larger proportion of non-NEM projects—35% by count and 32% by aggregate capacity—than in the NEM population. For SCE, withdrawn projects were 16% of non-NEM projects by count and 23% by aggregate capacity.

Recommendations related to the tracking of non-NEM project statuses include requiring that at a minimum, withdrawn projects are included in addition to in-service projects. Given the large number of other statuses for projects at various stages of the interconnection process, it may be appropriate to exclude other statuses or combine them into a common in progress status.

Non-NEM Project Sizes

Key findings from the segmentation into size categories of less than 30 kW, 30 kW-100 kW, 100 kW-1 MW, and 1 MW or greater include the following.

- The distribution of non-NEM project sizes skewed towards larger projects compared to the NEM populations. Projects less than 30 kW accounted for 42%, 20%, and 24% of non-NEM projects by count for PG&E, SCE, and SDG&E, respectively. However, these projects accounted for a very small proportion of aggregate capacity—0.2% for PG&E, 1.2% for SCE, and 1.2% for SDG&E.

- Projects greater than 100 kW accounted for a vast majority of aggregate capacity—97% for PG&E, 99% for SCE, and 96% for SDG&E.

Non-NEM Technology Types

The research team faced several challenges in identifying technology types in the data. Key findings from the segmentation of projects by technology include the following.

- In the PG&E and SDG&E non-NEM datasets, storage appeared in the main technology type field. However, there was no indication of other technology types present for these records, so it was not clear which were standalone or paired storage systems.

- The SCE non-NEM technology type field included multiple technologies and their individual capacities when relevant. This format allowed the research team to identify many unique technology combinations; the team groups combinations into simplified solar, standalone storage, paired storage, other, and unknown categories.

- For all three utilities, storage projects accounted for a majority of the non-NEM records by count. On an aggregate capacity basis, solar and other were the largest categories for PG&E and SCE while storage and other were the largest for SDG&E.

The following are recommendations for improving tracking and reporting of non-NEM technology type fields. The recommendations are similar to those provided for NEM projects.

- All reported projects should have a listed generation technology type to avoid classifications of unknown.
- Data should clearly distinguish between paired and standalone storage projects.
- Requirements should provide flexibility for reporting multiple technology types when an interconnecting project consists of multiple technologies or when the interconnecting project is an addition to an already-existing facility. When multiple technologies are reported, the capacity for each technology should be specified and these capacities should be consistent with the project size fields.

Non-NEM Reviews and Studies Performed

Key findings related to the segmentation by reviews and studies performed include the following.

- In the PG&E non-NEM dataset, the reviews and studies performed could not be determined for around 25% of records. Among the remaining records, most underwent only IR. SR occurred for around 8% of records and SIS occurred for only one project.
- In the SCE non-NEM dataset, the reviews and studies performed could not be determined for around 5% of records. Around 84% of the remaining records underwent only IR and around 13% also completed SR. The remaining projects required SIS. Only one project completed FS.

- In the SDG&E non-NEM dataset, all but one project required only IR. The remaining project completed IR and SIS. No projects completed SR.

The primary recommendation for improving tracking of reviews and studies performed is the same for non-NEM projects as for NEM projects. Data should include separate binary (true/false) fields that indicate whether IR, SR, SIS, and FS were completed for each project.

4.4.2 Rule 21 Timeline Performance

Table 112 summarizes non-NEM results for the analysis of key timeline steps discussed in Section 4.2. The steps analyzed were more consistent across the three utilities compared to the NEM timeline analysis because SCE and SDG&E provided more fields for non-NEM projects. The steps not analyzed are summarized in the following bullets.

- For PG&E, the time to complete SIS after IR or SR step was not applicable to any project. One non-NEM project completed SIS, but it did not complete IR or SR.
- For SCE, the time to complete SIS after DSA execution step was not analyzed because the data did not include DSA execution date; DSA execution date was not requested in the data request.
- For SDG&E, the time to resolve application deficiencies and the time to complete SIS after DSA execution steps were not analyzed; data required was not requested in the data request. The time to complete SR step was not applicable to any project.

Table 112. Summary of Non-NEM Key Tariff Step Timeline Results

Timeline Step*	PG&E Count	PG&E % Met	SCE Count†	SCE % Met	SDG&E Count	SDG&E % Met
Time to validate application	144	17.4%	911	25.0%	133	82.7%
Time to notify customer of application deficiencies	311	98.4%	122	55.7%	Not analyzed†	
Time to respond to notification deficiencies	143	49.0%	65	58.5%	Not analyzed	
Time to complete IR	131	34.4%	685	43.1%	132	72.3%
Time to complete SR after IR	11	27.3%	108	50.0%	Not applicable‡	
Time to complete SIS after DSA Execution	1	Met§	Not analyzed		Not analyzed	
Time to complete SIS after IR or SR	Not applicable		15	93.3%	1	Met
Time to send GIA to customer after IR or SR	101	76.2%	403	45.2%	127	96.9%
Time to send GIA to customer after SIS	1	Met	8	100%	1	Met
Time for customer to execute GIA	82	84.1%	408	80.6%	129	38.8%

* See Table 14 for the tariff-derived timeline requirements for each step.
† Not analyzed means that the analysis was not performed due to missing or incomplete data.
‡ Not applicable means that the step was not relevant to any project in the project population.

§ Met indicates that the single project for which the timeline analysis was conducted met the timeline requirement. Because the analysis population was only one project, a percentage result is not shown.

The non-NEM datasets included far fewer projects than the NEM datasets for each utility, so the count of projects analyzed for each timeline step are relatively small. Key findings from Table 112 related to timeline performance include the following.

- For PG&E and SCE, the step with the lowest adherence in the table was the time to validate the application relative to 10 BD. This is an indication that most applications had deficiencies that took extra time to resolve, which pushed the time to validate the application beyond 10 BD as allowed by Rule 21.
- PG&E timeline performance for other key steps ranged widely between 27% and 98%. The steps for sending deficiency notifications and GIA execution had the highest adherence rates. The steps for completing IR and SR had the lowest adherence rates.
- SCE non-NEM timeline performance for other key steps ranged between 43% and 100%. The steps for completing SIS and sending a draft GIA to the customer after completion of SIS had the highest adherence rates. The steps for completing IR and sending a draft GIA to the customer after completion of IR or SR had the lowest adherence rates.
- For SDG&E, adherence to the 10 BD benchmark for application validation was higher than the other utilities, suggesting that application deficiencies are less common or more quickly resolved. Adherence rates for other key steps ranged between 39% and 97%. The step for sending a draft GIA to the customer after completion of IR or SR had the highest adherence rate while the step for the customer to execute the draft GIA had the lowest adherence rate.

The research team also broke down results for each timeline step by project size and generation technology type categories. Unlike the results for NEM projects, there were not consistent trends or differences in timeline performance for projects based on size or technology type.

The research team also performed a high-level analysis of the total time for interconnection from application submittal to GIA execution or PTO to gain a broad understanding of the total time a project took to complete the interconnection process. Section 4.3 discusses the results of this analysis for non-NEM projects and the following key finding.

- Across all tracks, the full max requirement was met 95% of the time for PG&E, 89% for SCE, and 91% for SDG&E. The partial max requirement was met between 60% and 70% of the time for all three utilities.
- For the subset of projects larger than 100 kW and the subset of non-solar projects, the total time spent in the interconnection process was similar to the full non-NEM populations. This makes sense because the non-NEM population was less skewed towards projects less than 30 kW and solar projects than the NEM populations.

5. Study and Upgrade Cost Results

This section details findings related to study and upgrade costs. Section 5.1 discusses findings from the quantitative data and Section 5.2 discusses insights obtained from the qualitative interviews with utility staff and developers.

Rule 21 requires that certain customers pay for study costs, direct connection expenditures, and distribution level upgrades. Table 113 summarizes the fees for pre-application reports, interconnection requests, and certain studies as outlined in Sections E.1 and E.2 of Rule 21. NEM generators of limited size are subject to different cost ownership treatment and have waivers or discounted options for these fees and for upgrades. In particular, NEM-1 and ≤ 1 MW NEM-2 customers are not responsible for any distribution or network upgrade costs.

Table 113. Summary of Rule 21 Interconnection Fees

Ref.	Fee Description or Project Type	Amount
Pre-Application Report Fee		
A	Standard Pre-Application Report	$300
B	Enhanced Pre-Application Report: Primary Service Package	$225*
C	Enhanced Pre-Application Report: Behind the Meter Interconnection Package	$800*
D	Combined Primary Service Package and Behind the Meter Interconnection Package	$1,025*
Interconnection Request Fee†		
E	Non-NEM and > 1 MW NEM-2	$800
F	≤ 1 MW NEM-2	$145 (PG&E), $75 (SCE), $132 (SDG&E)
G	NEM-1	$0
Supplemental Review Fee†		
H	Non-NEM and > 1 MW NEM-2	$2,500
I	NEM-1 and ≤ 1 MW NEM-2	$0
Detailed Study Deposit for SIS or DGS Phase I Study†		
J	Non-NEM and > 1 MW NEM-2	$10,000
K	NEM-1 and ≤ 1 MW NEM-2	$0
Detailed Study Deposit for FS or DGS Phase II Study†		
L	Non-NEM and > 1 MW NEM-2	$15,000
M	NEM-1 and ≤ 1 MW NEM-2	$0
Additional Commissioning Test Verification		
N	Non-NEM and > 1 MW NEM-2	$150 per person-hour
O	NEM-1 and ≤ 1 MW NEM-2	Not Applicable
Cost Envelope Option Deposit		
P	All Projects	$2,500

* Fees for enhanced pre-application report requests are $100 greater if they exclude a standard pre-application report request.

† The first $5,000 of these study fees are waived for solar projects ≤ 1 MW that do not sell power to the utility (per D. 01-07-027) and do not participate in NEM-1 or NEM-2

5.1 Cost-Related Findings from Quantitative Data

As discussed in Section 2.3.3, the research team received limited quantitative data related to study and upgrade costs. The team identified the most cost-related data for PG&E, while the limited cost data received from SCE and SDG&E was from the sampling efforts. In general, utilities indicated that many cost-related fields were not readily accessible or not tracked or documented (e.g., not in database format and/or in a format requiring manual data collection).

5.1.1 PG&E Upgrade and Cost Results

As outlined in Section 2.3, the research team identified fields in the PG&E extract for estimated and actual customer, utility, and total costs for interconnection facilities and distribution upgrades. The team also identified separate fields indicating whether projects required upgrades. The data subsets for upgrades, estimated costs, and actual costs only partially overlapped, and most projects flagged as requiring upgrades did not have estimated or actual cost data. The rest of this subsection summarizes the records with upgrade and cost data.

Projects Requiring Upgrades

Table 114 shows the project type and size breakdown for the 768 projects with data indicating that upgrades were required. The table shows project counts and the upgrade rate (i.e., what percent of projects of a given type or size required upgrades) for the given project characteristic. Expanded NEM was the most common project type by count, but V-NEM, NEM-FC, and RES-BCT each had a higher rates of triggering upgrades. Standard NEM was the second most common project type by count to trigger upgrades, but it had the lowest upgrade rate.

Table 114. PG&E Upgrade Frequency by Project Type and Size

Project Category	Upgrades Count	Upgrade Rate (% of projects)
Project Type		
Expanded NEM	345	8.3%
Standard NEM	268	0.15%
NEM Multi-Tariff	75	1.5%
V-NEM	44	10.8%
Non-Export	12	7.3%
Standard NEM Paired Storage	10	0.71%
NEM-FC	10	19.6%
RES-BCT	3	14.3%
Continuous Uncompensated Export	1	8.3%
Project Size		
Less than 30 kW	380	0.2%
30 to 100 kW	137	7.0%
100 kW to 1 MW	230	11.2%

1 MW or greater	21	19.1%
Total	**768**	**0.4%**

Table 114 also shows that the upgrade rate clearly increased for larger projects, which makes sense because larger projects are more likely to exceed existing system limits. Only 0.2% of 30 kW or less projects triggered upgrades, while almost 20% of 1 MW or greater projects did. The mean and median size of the projects triggering upgrades was 179 kW and 31.9 kW, while the mean and median size of all PG&E projects was 11.2 kW and 5.1 kW.

Table 115 breaks down the projects flagged as requiring upgrades by project status and technology type. Around half of the projects with upgrades were in-service, and around 22% were withdrawn. The remaining projects were still in the study or implementation process. The table also shows that most projects with upgrades were solar projects, followed by storage and other, which is in line with the full project population.

Table 115. PG&E Upgrade Frequency by Project Status and Technology Type

Project Category	Upgrades Count
Project Status	
In-Service	377
Study in Progress	106
IA in Progress	104
Implementation	90
Withdrawn	82
Other	8
Decommissioned	1
Technology Type	
Solar	717
Storage	27
Other	15
Unknown	9
Total	**768**

Estimated and Actual Upgrade Costs

The research team identified the following fields related to estimated and actual customer or utility costs in the PG&E data extract.

A. Estimated/actual customer cost for interconnection facilities
B. Estimated/actual customer cost for distribution upgrades
C. Estimated/actual customer total cost (A + B)
D. Estimated/actual PG&E cost for interconnection facilities
E. Estimated/actual PG&E cost for distribution upgrades

F. Estimated/actual PG&E total cost (D + E)

G. Estimated/actual total cost of interconnection facilities (A + D)

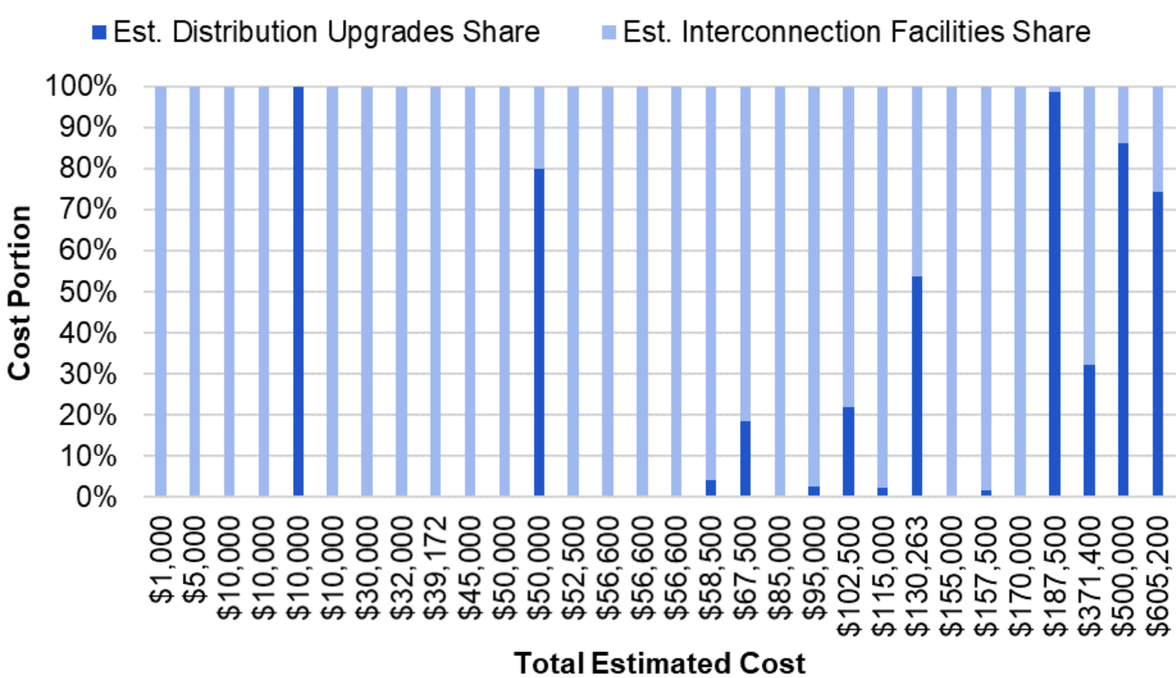
H. Estimated/actual total cost of distribution upgrades (B + E)

I. Estimated/actual total cost (C + F and G + H)

The research team found data entry errors or discrepancies in around 10% of the records with estimated or actual cost data where one of the "total" fields (C, F, G, H, I) did not equal the sum of its components. In these cases, the team used judgement to reconcile the numbers, which primarily consisted of fixing apparent typos or re-summing components to calculate a new total.

As noted in Section 2.3.3, the research team identified 30 records with estimated costs, 9 records with actual costs, and four records with both estimated and actual costs. Figure 11 shows the total cost and the share of costs for interconnection facilities versus distribution upgrades for each of the 30 projects with estimated costs. The total cost estimates ranged from $1,000 to $605,200. In most cases, costs were for mostly or completely for interconnection facilities rather than distribution upgrades. However, distribution upgrades contributed a considerable portion for several projects with relatively large total estimates.

Figure 11. PG&E Estimated Interconnection Facility and Distribution Upgrade Costs



Similarly, Figure 12 shows the total cost and the share of costs for interconnection facilities versus distribution upgrades for each of the 9 projects with actual costs. The actual costs ranged from $45,000 to over $616,000. The figure shows a similar trend in which most costs for projects with relatively small costs are for interconnection facilities, but most costs for records with relatively large costs are for distribution upgrades.

Figure 12. PG&E Actual Interconnection Facility and Distribution Upgrade Costs

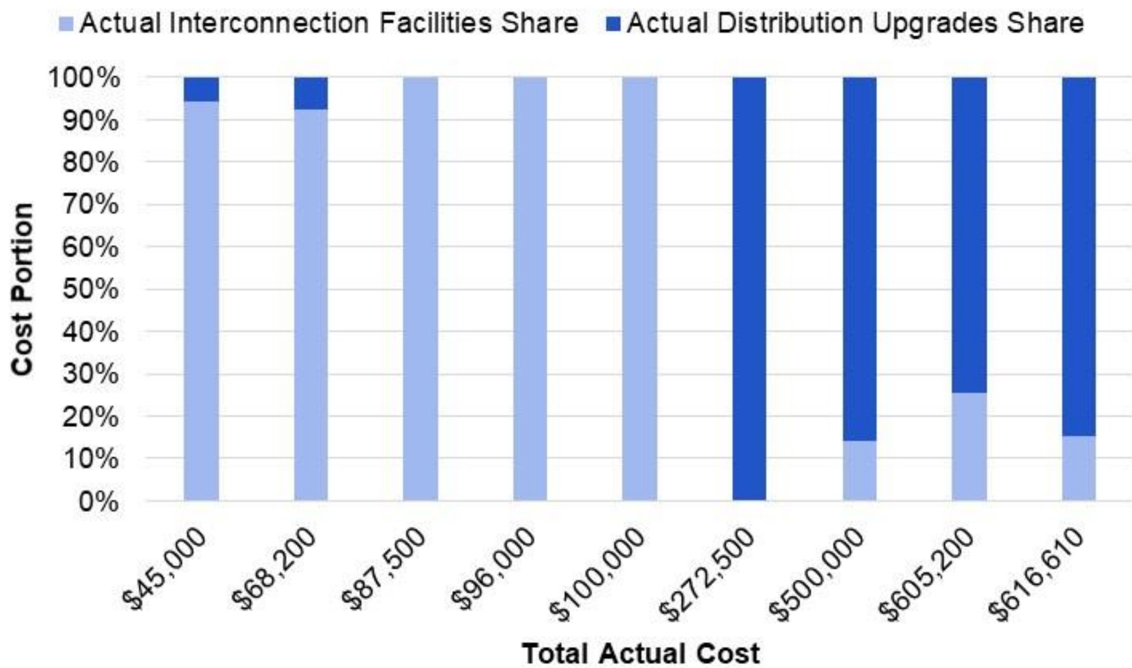


Figure 13 and Figure 14 show the cost responsibility breakdown between the customer and the utility for the 30 records with estimated costs and 9 records with actual costs, respectively. In both figures, customers were more often responsible for paying most or all of the costs than the utility.

Figure 13. PG&E Estimated Customer and Utility Cost Share

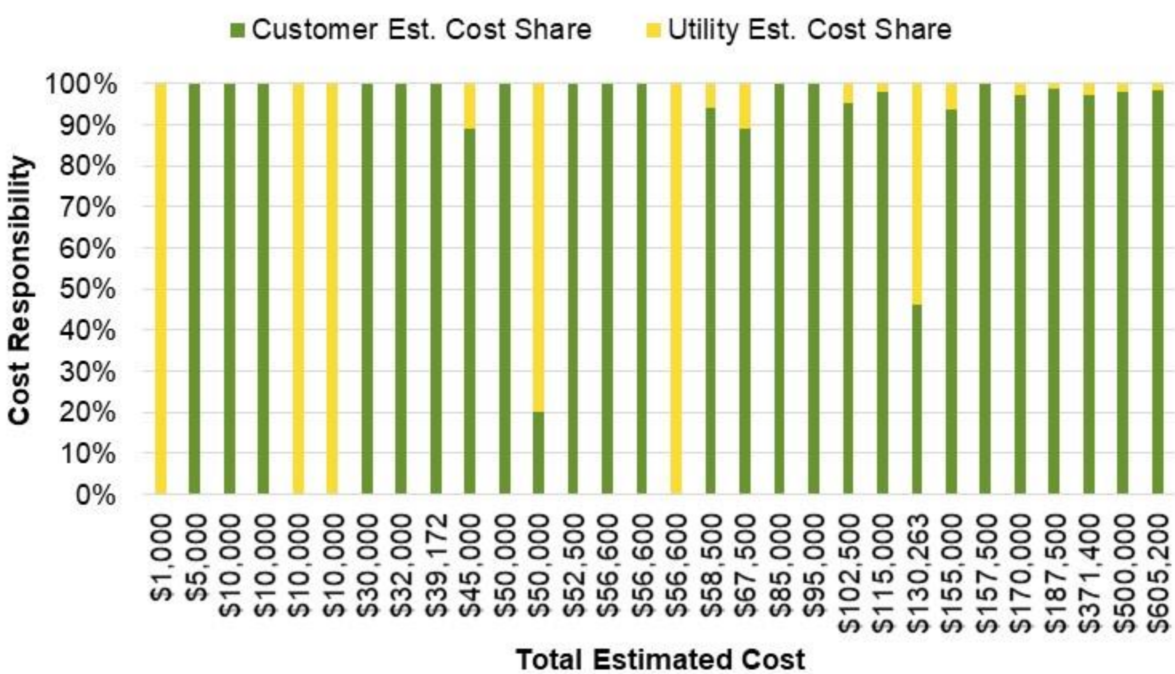


Figure 14. PG&E Actual Customer and Utility Cost Share

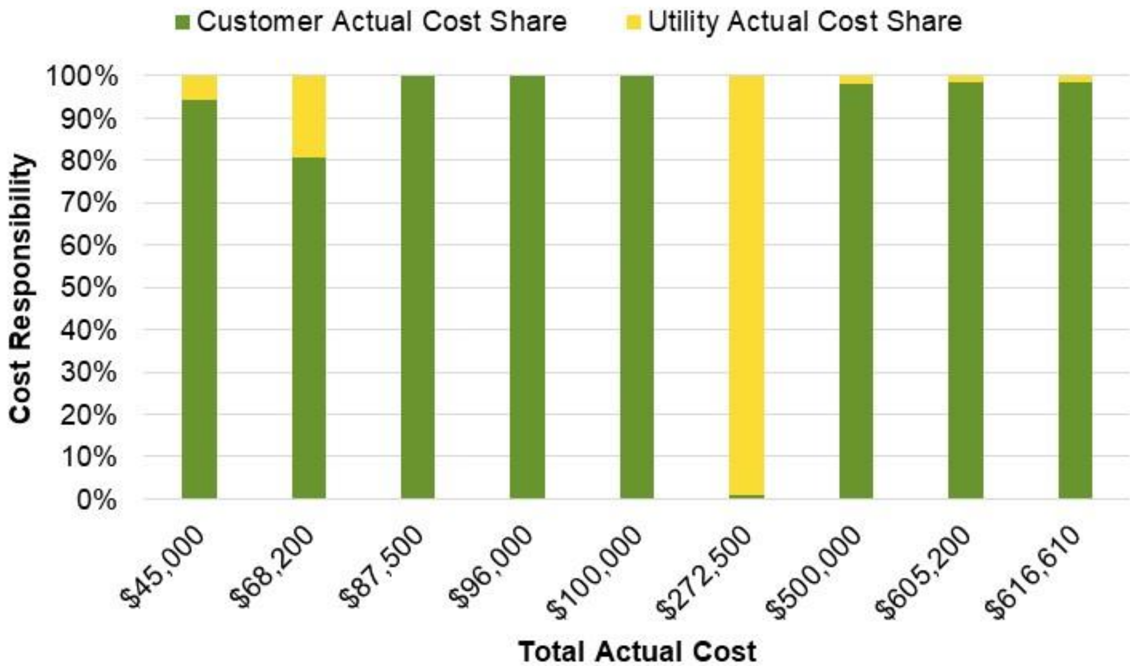


Table 116 compares the estimated and actual costs for the four projects with both estimated and actual costs. In the first record, the actual cost was $50,000 less than the estimated cost, and the actual customer share of 94.4% was less than the estimate of 100%. In the fourth record, actual costs were greater than the estimated costs by $461,610, and the increase was fully the customer's responsibility. In the remaining two records, the actual cost and customer share was the same as the estimated. The number of records analyzed is too small to draw broad conclusions about how actual costs compare to estimates.

Table 116. PG&E Estimated and Actual Cost Comparison

Record	Est. Total Cost	Est. Cust. Share	Actual Total Cost	Actual Cust. Share	Δ Total Cost	Δ Cust. Cost
1	$95,000	100%	$45,000	94.4%	-$50,000	-$52,500
2	$500,000	98.0%	$500,000	98.0%	$0	$0
3	$605,200	98.3%	$605,000	98.3%	$0	$0
4	$155,000	93.5%	$616,610	98.4%	+$461,610	+$461,610

Only 13 of the 30 records with estimated costs and four of the 9 records with actual costs were flagged in separate data fields for requiring upgrades. Of the 768 records that were flagged in fields for requiring upgrades, only 16 had either estimated or actual cost, and only one had both estimated and actual costs (record 1 in Table 116). The finding that cost data was not present for most projects marked as requiring upgrades and that cost data was present for projects not marked as requiring upgrades is an example of the sometimes incomplete and inconsistent data that limited this evaluation.

5.1.2 SCE Cost Results

SCE did not include any cost fields in the initial NEM and non-NEM data files; however, the research team requested data for estimated and actual detailed study and upgrade costs in both the NEM and non-NEM sampling requests (see Appendix B).

Only one of the 85 sampled NEM projects—a 2 MW solar facility—had cost data; for this project, the estimated cost of distribution upgrades was $60,000, and no actual cost was provided. No cost information was provided for the other sampled NEM projects. There is presumably cost-related data for other NEM projects in the population where detailed studies or upgrades were required, but the sampling effort with its limited sample size did not find any of these projects.

The non-NEM sample included more cost data. Six of the 85 sampled projects included data on detailed study costs paid by the customer, and the values were consistent with the detailed study deposit flat fees specified in Rule 21—$10,000 for SIS and $15,000 for FS (see Table 113). One project included the actual cost incurred by the utility for SIS, which was $4,000, or 40% of the customer's deposit.

Four of the non-NEM sampled projects had data for the estimated cost of distribution upgrades, though none had actual costs. Table 117 shows the estimated upgrade costs and key project characteristics for these four records.

Table 117. SCE Summary of Sampled Non-NEM Records with Estimated Upgrade Costs

Record	Project Type	Project Status	Size	Technology Type	Est. Cost of Upgrades
1	Non-Export	Construction	1.2 MW	Fuel Cell + Storage	$40,420
2	Non-Export	Construction	2.8 MW	Combustion Turbine	$70,000
3	Rule 21 Export	Construction	3 MW	Cogeneration + Storage	$210,300
4	Rule 21 Export	Construction	3 MW	Steam Turbine	$1,883,750

5.1.3 SDG&E Cost Results

In the SDG&E sampling effort, the team collected data on customer study costs for the one project that completed SIS. The cost was equal to the $10,000 flat fee specified in Rule 21, but the actual cost of the study was not available.

SDG&E staff confirmed that no in-service projects in the 3-year study period required distribution or transmission upgrades. Therefore, fields related to estimated and actual upgrade costs were not applicable. SDG&E staff noted that the only costs incurred for projects were Rule 2 costs for net generation output meters, wiring, or telemetering. No projects have utilized the cost envelope option.

5.2 Cost-Related Findings from Qualitative Interviews

Rule 21 presents a cost allocation scheme categorized with triggered decisions of interconnection standards and requirements to fairly distribute incurred costs to integrate generating facilities. Results from interconnection track supplemental reviews and impact studies often warrant additional costs for the applicant to allow for utility-identified upgrades and mitigations to the distribution system. In addition to evaluating received data from the IOUs, the research team performed several conversational interviews with IOUs and developers to supplement data analysis findings through shared primary and secondary experiences. Developers held project experience assisting customers within residential communities, small through large scale commercial, agricultural, and municipal facilities with DER sizes ranging from 30 kW to several MWs. Technologies for facilities covered behind-the-meter PV and battery storage configurations. Feedback from interviewees presented findings of nuanced and rare cost occurrences, unanticipated expenditures, the framing and implementation of cost certainty, areas that are effectively streamlined in administration, and instances where delays occur with respects to payment receival and milestone completion.

5.2.1 Nature of Upgrades and Mitigations

Ahead of receiving PTO for DER configurations, the utility determines applicable changes needed for the distribution grid in order to accommodate oncoming generation and to maintain safety and reliability operational standards. These modifications to electrical equipment occur when system impacts are identified necessitating upgrades to the network to increase circuit hosting capacity and service deliverability. Under the current framework, the utilities work with developers and interconnection applicants and provide non-binding estimates of anticipated costs, which may not reflect actual cost of ownership and total customer fees. As described in Table 113, fees and deposits are categorized and codified by Rule 21 aligning to interconnection track milestone achievements. Developers and utilities agreed that cost itemization requirements that are automated per the tariff are clear to the customer and generally result in minimal deviations from estimates. The accuracy of calculating these costs ahead of construction phases of the interconnection process beyond the established Unit Cost Guides and Cost Envelope Option are dependent on several factors, including classifications such as deployment capacity size, scale, voltage, and generating output of the planned facility. Interviewees noted that upon reaching the construction phase of the interconnection process, cost certainty is less apparent. Nearly all standard NEM projects arrive within an acceptable range of estimated costs as opposed to non-NEM, NEM-2 or NEM-A, where system expansion and remedies may be required.

IOUs communicated to the research team common and uncommon upgrades found throughout the study term. PG&E noted that transformer upgrades are commonly identified with mitigations related to substations, reclosers, and telemetry. SCE reiterated these common upgrade occurrences but relayed that majority of triggered upgrades may result in the withdraw or system modification of the project to eliminate prompted enhancements. SDG&E specifically shared that transformer upgrades are common and that these initiatives are not executed during the interconnection study window. Additionally, the IOUs apply a fixed cost structure for facilities under respective NEM tariffs. Uncommon upgrades include mitigations for control buildings, expansion of substation perimeters, and moving access roads.

Developers agreed on the nature of upgrades and mitigations experienced throughout the interconnection process. In general, upgrades are generally uncommon for all three utilities and absent for facility installations of 1 MW or lower. Mitigations for most projects that trigger upgrades are discussed in results meetings and that developers concurred that the effort was initiated under a collaborative process. There exists a consensus among developers, reporting that upgrades are required for safety and reliability per each utility’s compliance and adherence to system design and electrical standards. In general, instances of unnecessary charges for unrelated work are not allocated to the applicant. However, three developers conveyed anecdotal examples where initial estimates misaligned with actual bill statements, requiring deliberations of whether impact to the distribution system was in part a result of the oncoming facility. Where technical discussions and further meetings are required to understand each mitigation or upgrade proposed, the developers commented that IOUs were all generally responsive and open to reviewing proposed construction activities. Specifically, for non-export projects, telemetry requirements almost always require additional conversations with the service planning and interconnection representatives at each respective utility, but more notably for PG&E.

Both interview groups noted that adverse impacts measured by system and facility studies will lead to the burden of cost on the interconnection applicant. Some exemptions exist, represented by PG&E, stating that internal business policy is to make best attempts to spread the costs of distribution system upgrades fairly and pursuant to utility tariff programs. Incremental enhancements are not captured in allocated costs including other work that is not the directly a result of the customer's interconnecting facility, though, additional work may be performed concurrently with Rule 21 project-specific upgrades. SCE noted that system upgrades triggered by increases in load are funded by ratepayers, as applicable/pursuant to SCE tariffs. SDG&E also shared that for generation-driven transformer upgrades, the interconnecting customer would pay if it serves only that single generating facility. If it serves multiple customers, then the entire rate base would pay for the upgrade.

5.2.2 Accounting and Costing

Cost certainly is provided to interconnection applications through established Unit Cost Guides in accordance with D. 16-06-052 in addition to the study and processing fees stipulated in each respective GIA. The Unit Cost Guides are presented with clear voltage and sizing requirements per unit with costs clearly expressed for each mitigation or upgrade. This includes overhead costs embedded into pricing structures for clear understanding of the fee components. The IOUs commented that final billing statements are trued-up at the end of the construction phase, which can result in increases to the estimates or unforeseen delays. In general, developers agreed that presentation of accessible information referring cost estimates, deposits, and associated fees are clearly laid out to the customer. A common grievance experienced among developers was the inadvertent delays that occur during routine business practices. If estimates are questioned and subsequently recalculated, developers noted a minimum 72-hour window of anticipated reciprocation from IOUs unless receiving push notifications through portal applications.

Developers engaged in working group and interconnection discussion forums have generated internal cost forecasting methodologies that align with historical deployments managed under their interconnection programs. This resource has provided cost certainty for developers to clearly and effectively communicate anticipated upgrades, incurred fees, or system design mitigations to preclude the need for distribution system enhancements. In addition to these internal documents, developers rely on the Unit Cost Guides issued by each IOU and the Integration Capacity Analysis tool to understand sizing and cost requirements when planning deployments. Developers also expressed concerns regarding the latency in updating the Integration Capacity Analysis backend datasets to accurately forecast project requirements for applicants. PG&E usually has cost estimates significantly higher than final numbers once surveyor inspects equipment. Study costs are viewed directly from Tables 1.E in each GIA and are generally understandable to the customer. Uncertainty arises for specific technical cut-offs, such as an example relayed for whether 1 MW AC or CEC-AC criteria would trigger a subsequent step. In comparison to other electric tariffs, Electric Rule 16 costs better itemized than Rule 21 costs, according to developers.

Cost Envelope Option

The research team inquired each IOU and developer the event the Cost Envelope Option has been considered and utilized. While considerable effort in developing this cost certainty structure, a majority of Rule 21 distribution network enhancements are simple transformers size upgrades to account for oncoming generation, which has eliminated the need for the Cost Envelope Option in practical utilization, according to both developers and IOUs. Specifically, PG&E shared that the Cost Envelope Option has only been utilized a few times with no projects reaching PTO. Similarly, SDG&E echoed no fully executed project has utilized the option. IOUs opined that due to the infrequency of atypical upgrades and mitigations, the Cost Envelope Option has not been highly requested or investigated with interconnection applicants. For projects that do require costly upgrades, the risk associated with actual costs exceeding estimated costs is likely less concerning; rather, it is the need to pay for any upgrade costs. Additional comments mentioned projects likely to elect this option would often move into WDAT as utilities have largely phased out procurement programs for front-of-meter distributed generation.

6. Interview Findings and Utility Business Practices

While Sections 2, 3, and 4 focus on the quantitative data gathered for actual projects to assess timeline and cost performance relative to Rule 21, Sections 5 and 6 feature the evaluation's qualitative findings through conversational interviews with IOUs and developers. As discussed in Section 2.2, the research team conducted interviews with each IOU to understand their business practices and internal interconnection processes. The team also interviewed developers who have worked on interconnecting projects under Rule 21 to obtain information on their experience with the process and each utility. These qualitative responses were used to assess program implementation effectiveness and identify areas for improvement.

The research team confirmed findings with external supplemental resources including the current applicable CPUC proceedings, interconnection dispute trends, working group papers, IDF documentation, and alignment with themes captured from the California Energy Commission's 2019 "Lessons Learned and Best Practices from Seven EPIC Funded Microgrids Awarded in 2015," which included developer and IOU interview facilitation by members of this research team.[16]

The following subsections summarize and compare IOU responses in the topic areas of organization and workflow, customer service, and other initiatives and process improvements. As applicable, the subsections summarize developer feedback relevant to that topic.

6.1 Organization and Workflow

The subsections below categorize the business process-related elements used to administer Rule 21 under utility-specific internal practices. Discussion beneath each IOU description table depicts the insights from the developers' experiences in navigating the interconnection process. The research team captured discussion points from each interview surrounding the challenges, successes, and recommendations as it relates to tariff adherence in real-world applications.

[16] California Energy Commission, Docket No. 19-ERDD-01. "Notice of Staff Workshop: Lessons Learned and Best Practices from Seven EPIC Funded Microgrids Awarded in 2015," April 26, 2019.

6.1.1 Online Portals

Pacific Gas and Electric Company (PG&E)	Southern California Edison	SDG&E
• Has web application portals for Standard and Expanded NEM programs, where customers can submit applications, view and monitor projects, upload project documents, and check project status (except Standard NEM) • Assigns an interconnection manager for communications and input/output documents • Currently three different portals, but a new single portal is coming soon	• Prior to 2015, used customer relationship management software • Since 2015, using PowerClerk Inc. (PCI) • Customers create account in PCI to log in and view all applications and check project statuses • Customers receive email notifications on status change • Starting December 2019, has a new application, Grid Interconnection Processing Tool (GIPT), for all new Rule 21 Non-Export Interconnection requests • Wizard assistance feature providing navigational guidance and requirement references	• Uses My Partners application portal – including: Distribution Interconnection Information System (DIIS), Pole Information Data System (PIDS), and Microsoft Teams • Software moves/notifies applicant of project updates automatically • Contractors can log in to DIIS to view project status • Recently launched consumer protection • Team of 12 representatives routinely evaluates and streamlines applications

Developer feedback: Respondents within the developer pool maintained responsibility providing interconnection process support for customers from application submission to receiving PTO. There exists a consensus among developers indicating the ease of use of the three interconnection process portals. They are relatively responsive and user-friendly, taking note of the advancements in site features for better navigation over the last two years. Developers appreciate the ability to track projects in a way that does not require a phone call or an email. This is not consistent for projects with advanced technologies, design complexities, or that are greater than 1 MW. In practice, a majority of developers commented on the frequent need to contact PG&E representatives from EGI, service planning, or engineering departments individually. Not all submitted information is retrievable among the website portals. With a 10-megabyte file size constraint and limits on the number of files and file types, application package submittals are often challenging for the less-experienced interconnection customer. PG&E portals were noted to present a static (view-only) review after submission necessitating the need for an email exchange for clarifying photos or resubmitted materials during later stages of the interconnection process, especially when department handoffs occur. PG&E's planned migration into a singular portal or receival database is highly anticipated. Additionally, developers appreciate the dynamic portals of SCE and SDG&E. SCE has improved notably over the past few years. For example, customers are better enabled to make informed decisions on which DER program is right for them through the DER application wizard. Developers are also looking forward to the move to GIPT. In the future, developers would like integrated utility systems and API portals to automatically submit multiple applications at once.

6.1.2 Recordkeeping Mechanisms

PG&E Pacific Gas and Electric Company	Southern California Edison	SDG&E
• SAP Database • Physically archived documents and emails • Portal automated notifications and alerts • Computer-based document tracking with some reliance on physical files and binder systems • Field and engineering notes as well as meetings summary documents from mixed documentation resources	• In the long run, GIPT will be used as centralized document repository • Once a project reaches certain milestones, information will move to/reside in GIPT • Physically archived documents and emails • Portal automated notifications and alerts • Computer-based document tracking with some reliance on physical files and binder systems • Field and engineering notes as well as meetings summary documents from mixed documentation resources	• DIIS • Portals within the system allow uploading and storing large files • Physically archived documents and emails • Portal automated notifications and alerts • Computer-based document tracking with heavy reliance on physical files and binder systems • Field and engineering notes as well as meetings summary documents from mixed documentation resources

Developer feedback: As noted above, information retrieval is not uniformly successful among types of data files and mechanisms in which they are stored. Developers noted that paper and binder-filled records require scanning and physical time searching for relevant information, which may not be as useful nor effective as opposed to online database repositories. Interviewees also relayed issues with GIAs not being searchable in PDF readers or convertible to word processing formats. Information that is communicated via phone, email, or in-person is not captured in results summary meetings or subsequently on any form of notification pushed through the automation features within the portals. Some developers commented that SCE did capture key notes into the project file and that the recordkeeping architecture is upkept and generally updated on a timely manner. For all Standard NEM projects applying to all IOUs, developers mentioned that mechanisms to record information are more efficient and streamlined.

6.1.3 Coordination Between Departments and Offices

PG&E Pacific Gas and Electric Company	SOUTHERN CALIFORNIA EDISON	SDGE
• All coordination through SAP database and workflow management system • Engineer gets listed as a partner and gets alerts for updates • For NEM projects <1 MW, process is centralized through a single inbox based on NEM program type (as of August 2017) • All other projects have a single point of contact from application through PTO and first bill; includes IA, construction, and implementation	• All coordination through PCI • Most status changes triggered in PCI • PCI handles the issue automatically	• Email system for automatic notifications addressed within the team of 12 representatives • Siloed procedure to hold specific groups/teams responsible for phases in the interconnection activities • Provides accountable quality checks per tracked stage of the process

Developer feedback: All IOUs present similar contact and correspondence procedures for NEM projects <1 MW. NEM inboxes serve as a centralized repository for smaller and fast track applications, providing no direct utility project manager assigned to an individual project, but rather, a team of representatives that address inquiries as received. Developers concurred that delays or disputes related to smaller DER projects under NEM are less likely to occur and that a direct project contact per NEM application is not a necessity. Ideally, improvements to utility case management strategy are thought to best address many instances of interconnection customer grievance. The developers noted delays when the utility project managers require input from PG&E engineering teams and would like to see improved communication between departments. Delays also occur when there are transfers to the service planning department. Some developers noted success coordinating directly with EGI supervisors and known contacts handling other applications.

Developers gave recognition to named personnel within the PG&E EGI team in assisting interconnection customers while balancing multiple responsibilities. The challenges occur when utility staff are shuffled out and transitioned into other roles or when turnover occurs. Resource sufficiency has been both an internal and external challenge among all IOUs as subject matter expertise often does not get transferred to the onboarding or newly assigned application representative. Developers agreed that this issue can be remedied with more thorough tracking of project updates, modifications, and inquiries while progressing through the interconnection process. For PG&E, developers pointed out that physical staff realignment among various offices may address the imbalance of request loads and could improve customer coordination and response through regional redistribution of utility representatives or responsibilities. The research team received positive feedback regarding SDG&E coordination efforts. The utility provides an adequately sized team to handle the fluctuations of interconnection applications.

Lastly, developers shared that SCE generally coordinates among offices for information hand-offs well without any variant issues.

6.1.4 Planning and Accountability

PG&E Pacific Gas and Electric Company	SOUTHERN CALIFORNIA EDISON	SDG&E
• Uses a vendor to provide resources for smaller projects • Scales up/down depending on volumes • Number of requests have stayed constant, but the mix of technologies has changed; storage has increased complexity • IT systems investment to automate processes to reduce workload	• Since 2015, the number of applications/projects has been consistent at around 4,000 per month and is expected to stay at this level • PCI helps manage workflow • Need for more or less budget and resources is requested through general rate case	• Responsive to applicant and contractor inquiries and concerns to resolve issues expeditiously • Software communicates status to customers/installers

Developer feedback: Many automated and tracked processes within the interconnection portals and email systems allow the utilities to establish internal metrics and accountability strategies to ensure delays, disputes, and common grievances are addressed in a timely manner.[17] While much of this information is regularly tracked, developers did not communicate utility demonstrations of internal quality check/quality assurance apart from an audit or data reporting environment. The interviewed developers are accustomed to facilitating numerous applications simultaneously, which does offer a secondary reference for project-related information and milestone movement. Consequently, developers then fall into a position of informing new utility representatives when making hand-offs or coordinating between departments. Ensuring a structure for utility interconnection accountability would reduce the burden of developers and applicants to maintain records in concert with the utility.

All IOUs provide data updates to the ICA tool allowing developers to internally plan projects based on best available data. Each developer appreciates the ability to utilize the ICA in combination with publicly available DER statistics aggregators to forecast and provide timeline estimates to their customers seeking interconnection. They opined that utility internal distribution planning is frequently updating, often rendering the ICA depictions useless when that internal queue process insight is not available. IOUs receive high volumes of interconnection requests on a monthly basis, and while not all projects reach operational status, IOUs could optimize resources and supplement with third-party resources to meet these waves of high application volume effectively.

[17] either noted in the tariff or otherwise communicated estimate in BDs with the applicant.

6.1.5 Use of Third-Party Vendors

Pacific Gas and Electric Company (PG&E)	Southern California Edison	SDGE
• Each step of the process has its own rules surrounding third-party resources and is evaluated case by case • For larger projects, it becomes difficult as new technologies penetrate the grid, resulting in lags for business practice adaptation after industry changes	• Uses third-party engineering contract resources to help with NEM project evaluations	• Work through technical issues and resolve with customers and contractors • Interconnection data used to support analytics for other planning studies such as total deployment numbers, capacity, storage saturation, business impact, etc.

Developer feedback: Developers provided similar responses to those referenced in Section 6.1.4. Where noted and assigned a timeline requirement in BDs in Rule 21, developers see no trending issues when engaging or working through third-party entities. However, they note that communication gaps can form between utilities and independent vendors. Complex designs including advanced devices, or a technology change can delay correspondences with third parties, though in general, is not a significant concern.

6.1.6 Verifying Tariff Compliance

Pacific Gas and Electric Company	Southern California Edison	SDGE
• SAP is the workflow management system, which provides a view of upcoming tasks • Everything is documented in SAP—service characteristics, project information, monitors, and timelines • Notifies the applicant as the timelines approach, including delay notices • Daily red, amber, green report for outstanding projects with a 3-day out or 1-day out view • A report for outstanding projects but no open tasks notifying to open an inquiry or task for the utility	• Does not perform field inspections or audits because it can be resource-intensive • Projects >1 MW have telemetry • Reports to show any projects that are stalled; try to follow-up, see why things are stalled • Relies on project managers to manage the process and keep projects on track • Relies on the new portal system to help enhance visibility into overall timelines; expect more visibility as more projects get migrated to the new system	• Routine self-evaluation • Multiple data requests on timelines and activities leading to any internal process enhancements to continue to meet timeline milestones • Call center has specially trained NEM specialists who can answer NEM questions, assist with NEM rates, and provide general status updates • Inquiries are routed/ escalated to interconnection group as needed

Developer feedback: The program reforms to streamline Fast Track projects have been effective over the last few years. A mentionable takeaway from two developers specifically noted that they have not had utilities perform field inspections for any project under 10 kW. Developers did not speak significantly about the processes that are working well regarding tariff adherence specific to BD requirements for milestones and step movements. Instead, the focus of discussions leaned on the frequent delays in responding to customers and administering remedies and resolutions to concerns. Customers have access to the status of their project through the application portals and can see when it moves through the interconnection process allowing the ability to verify adherence to the timelines stipulated in Rule 21. Assigned project managers for larger projects maintain records of the process steps, which verifies tariff adherence among portal report updates and status notifications. As stated previously, the later stages of the interconnection process ahead of construction begin to present unclear expectations for the timeline to effectively receive PTO.

6.2 Customer Service

6.2.1 Communication and Responding to Inquiries

Pacific Gas and Electric Company (PG&E)	Southern California Edison	SDG&E
• Carried out primarily via email; SAP tracks progress and communication activities • Conference calls with engineers if issues are elevated to resolve • Moderate and coordinate conference calls if applicants need to speak with engineers assigned to their project • Website provides communication instructions; application desk manages inquiries unless escalated to involve the interconnection manager or whomever necessary	• NEM – Automatic notifications through the interconnection portal with responses sent through the portal by a dedicated analyst – Goal is to respond within 2 BD; most inquiries are addressed the same day – General inquiries go to nem@sce inbox – Customer surveys to assess performance • Non-NEM – First line of response comes from assigned contract manager or project manager/advisor – Dedicated intake group that responds to inquiries within 3 BD – Throughout project life cycle, there is always a single clear point of contact and a handoff via whatever medium the customer needs – Contract manager is the contact during interconnection evaluation and contractual development; construction manager after IA	• Dedicated team tracks overall project and reaches out to other groups as needed • Internal goal is to return phone calls and emails same-day • Centralized dedicated mailboxes that everyone on the team can access; always someone scheduled to answer dedicated phone line Monday-Friday • Call center has scripts to immediately answer common questions but escalate as needed

Developer feedback: The developers stated they have good working relationships with the SDG&E interconnection team, who are typically responsive to any issues. While a majority of projects are sited in PG&E's service territory, anecdotal representation of SCE and SDG&E interaction provided the basis for these responses. The developers reported having difficulties reaching PG&E staff, who can be unresponsive to repeated emails and calls. For the rare projects that require additional discussion or clarifications, SCE and SDG&E generally provide timely responses within a two to three-day window unless additional coordination is needed from a different department. It is much more challenging to receive a similarly timely experience with PG&E due to the siloed nature of the service planning groups and volume of interconnection requests sorted by the EGI team.

6.2.2 Project Managers, Points of Contact, and General Communications

Pacific Gas and Electric Company	Southern California Edison	SDGE
• Standard NEM and Expanded NEM <1 MW and Standard NEM-A use common email boxes • For projects >1 MW a specific interconnection manager is assigned • If it is a queued project, it goes through the application desk first before going to an assigned interconnection manager • Email communication about next steps and any changes in the middle of a process/project	• In new GIPT portal, the wizard helps with project path selection • Non-NEM projects are assigned a project manager • For NEM projects >1 MW or any project that triggers upgrades, there is a dedicated point of contact • Welcome package at the start of design/construction that includes all requirements for design phase, engineering phase, commissioning • When technology changes outside of requirements, that is when delays occur because additional documentation is required • Additional training for engineers to keep up with changes (e.g., creating list of approved controls, templates, additional screens) • Recent investments made into engineering and planning capabilities for DER integration	• Single point of contact for large projects • Constantly in contact with contractors to build working relationships

Developer feedback: Developers reported having clear points of contact with SCE and SDG&E; however, its less clear with PG&E. They noted that it can be frustrating to get stuck in a general inbox for Standard NEM queries, which can be expedited with an assigned manager, like for NEM-A. More specifically, the developers stated the following for each IOU:

- For PG&E, the developers would prefer having a single point of contact but find that delays can occur when the assigned project manager is out of office or transferred to a new point of contact. At times there is no notification of the transfer. Some projects have been repeatedly handed off to new managers, and the developers need to repeat the same info to each new person. Staff turnover makes it difficult to know who to reach out to.
- Developers note that handoffs occur frequently at SCE over the course of a project, which can lead to delays. Developers reported minor deviations from the handoffs when recalling SCE interactions as compared to the other utilities.
- SDG&E’s interconnection team is small, and the developers reported the team is focused and easy to work with.

6.2.3 Consistency of Customer Experience

• Most of PG&E's communications use templates for consistency, such as email notifications for changes, to help customers navigate the process • Status calls are not common • SAP notifies of the results meetings	• First-in-first-out for all NEM customers - i.e., all customers are treated equally • Training material on Rule 21 process for engineers and staff for consistency • Mandated results meetings with customers and contractors/consultants	• Small informal group • Open communication with all customers, developers, and contractors

Developer feedback: The developers noticed differences among parties in knowledge of Rule 21 during the working group sessions and that this may be a common experience with smaller developers and new interconnecting applicants. They suggested this is an area where the public can benefit from more educational resources on the expectations of interconnecting, for which mechanisms like the IDF exist. Interviewees also stated that they do not feel there is a bias against smaller developers nor do utilities encourage a preferred vendor, rather, they serve as a conduit to available developers based on the needs and design configuration of the DER. Utilities take a prudent approach in allowing the customer to select the right contractor and technology that aligns to their DER pursuits IOUs are also careful to treat all contractors consistently. To better equip smaller developers lacking institutional knowledge of Rule 21 in its development, additional educational materials are requested. tutorials, FAQs, webinars, instructions with example answers to application questions, common deficiencies, system impact potentials, and other associated technical specifications would be valuable going forward.

6.3 Other Initiatives and Process Improvements

PG&E Pacific Gas and Electric Company	SOUTHERN CALIFORNIA EDISON	SDGE
• Process improvement is continuous and focused on customer experience and regulatory and industry changes	• SCE conducts a voice of the customer survey after getting PTO • Unhappy customers are forwarded back to the interconnection team • Utility tries to be proactive with new technology requirements by conducting webinars and emailing customers to help educate • SCE did survey of customer base in 2019 that received good feedback and areas to improve; tries to do the survey periodically	• Process improvement: prepopulating data on existing systems when adding storage to existing systems • Mobile app that provides instant inspection approvals

Developer feedback: Developers reported lack of response or movement for issues brought forward multiple times in meetings with utilities or in stakeholder sessions. Developers would like improvement in working groups and IDFs going from discussion to action and suggested building a roadmap for implementation after each ALJ decision to increase transparency. This roadmap would help contractors to know when to expect changes and help the developers avoid repeatedly bringing up issues. Recommendations for more frequent updates to the ICA backend datasets reflected developers' desire to have accurate planning tools to effectively map timelines and deployment schedules for interconnection applicants. The CEO is less understood in practical use as none of the developers interviewed had direct experience selecting and assessing the effectiveness of the CEO. Specifically, developers felt that using internal cost estimators and the Unit Cost Guide provide suitable references for accounting for foreseen and unforeseen cost allocation. DERs that are < 1 MW do not benefit from the CEO, as the required deposit ($2,500) discourages its use when minor system enhancement efforts are expected.

6.4 Summary of Interview Findings

As discussed throughout Section 6 the IOUs maintain varying tools, systems, and processes to implement their Rule 21 interconnection programs. While the developers, who reported an overall satisfaction and appreciation for the consistent improvement in IOU business processes, identified areas of improvement that included:

- **Organization and workflow**
  - Portals vary in number and functionality across utilities but are viewed as generally user-friendly. Developers prefer dynamic portals that allow communication and uploading documents after submission to reduce the need for follow up via IOU representatives or outright resubmission. U Other challenges arise when uploading large files, multiple files, or pictures as a result

of size limitations and restrictions embedded in the design of the webpage or milestone status.

- Retrieving or verifying submitted information is more challenging for non-NEM and NEM-2 projects. Standard NEM applications generally do not experience workflow issues. Information is captured through the portal features with enhancements to data recordkeeping practices taking shape over the last two years for SCE and PG&E. Deficiencies in application packages are notably frequent, causing logistical hurdles that at least one developer referred to as simple issues that do not warrant more administrative time than a prompt phone call. These impacts are often burdensome for both the utility and applicant. Developers recommend the ability to quickly resolve deficiencies in a manner that does not add significant time to the schedule or trigger a reapplication process.
- The developers acknowledged the historical enhancements made to streamline projects eligible for Fast Track. While this is encouraging in understanding utility adherence to the tariff requirements, many issues remain as identified by the working groups and IDF. Developers recommend regulatory or programmatic enhancements to address the IDF and working group outcomes receiving minimal refinements for nuanced or advanced technology projects.
- Handoffs in the utility are generally triggered through step progressions made by the software systems but can suffer from incomplete transfer of information or delays in turnaround response times. The IOUs do not include into the portal repository all information related to project such as representative-captured notes, updates, and emails. Developers urge for an administrative process to better link project application package materials with associated project details (e.g., emails or call notes between utility representatives and the interconnecting applicant).

- **Workforce and compliance**
  - The number of interconnection requests been relatively consistent over the study period with some swings in request volumes throughout the year; third parties and vendors are used more for small NEM projects.
  - Utilities have made investments to automate routine processes and reduce workloads.
  - Utilities use software systems, internal reports, and self-evaluations to monitor timelines and requirements.
- **Customer service**
  - Utilities have different processes for responding to inquiries based on project type or size. There are general email inboxes for NEM but dedicated managers for non-NEM projects, large projects, or projects requiring upgrades or utility construction.
    - Developers appreciate dedicated project managers, but delays can occur due to change in project manager staffing, inconsistent communication, or multiple handoffs.
  - Developers spoke highly of communication from SDG&E, but they expressed frustrations with reaching PG&E via phone or email. SCE and PG&E have

responsive personnel, but developers estimate a response window of around three days for minor/straightforward requests and up to five days for more technical inquiries. Developers frequently need to reach out multiple times It is not uncommon for a developer to reach out multiple times prior to receiving a response.

- Utilities stressed their consistency in treating interconnection customers akin to developers. At the same time, they understand that a higher degree of consumer education is necessary when working with a single applicant or smaller developers within the state.

- **Stakeholder mechanisms**
  - Developers spoke to the usefulness of working groups and stakeholder sessions; however, they identified a lack of forward momentum —One developer noted that "sometimes issues need to be raised multiple times and under multiple forums".
  - Leverage concepts from stakeholder engagements to visualize a process decision-tree that outlines project scenarios based on various interconnection installations to drive better decision-making for applicant needs and manage expectations of Rule 21 requirements.

7. Key Findings and Recommendations

The research team worked with the IOUs and other stakeholders to gather qualitative and quantitative data to assess the implementation of Rule 21 between July 2016 and June 2019. Guidehouse analyzed the data to develop key findings and recommendations, which are summarized in this section by topic.

The recommendation categories described below are related to areas communicated by stakeholders as needing visible improvement in utility administration or the tariff, where administrative implementation of Rule 21 can be more efficient, as well as recommendations for future ED-led assessments to enable continuous improvement to Rule 21. The conclusions and recommendations below do not express the inherent opinions or thoughts of the CPUC nor Guidehouse evaluation team and were derived from synthetized data analysis results and feedback from vested stakeholders. To balance reported results and significant findings, the research team acknowledged similarly conducted assessments, parallel CPUC proceedings, and complementary state-driven reports upon finalizing the key recommendations. Further, the research team reviewed working group issues, quarterly interconnection reporting forms, common interconnection process grievances, and stakeholder DER integration reports to assure the quality of captured statements and verification in representing the interviewees' relayed experiences.

7.1 Data Tracking and Reporting

The research team, with input from stakeholders, developed a quantitative request of 77 fields for interconnecting projects between July 2016 and June 2019. These request fields captured the interconnection details routinely tracked among the IOUs and provided the basis for the data analysis phase presenting in this evaluation.

Finding: Differences in the document formats, applicability of requested fields, and accessibility of tracked project-level interconnection data among the utilities made it difficult to comprehensively and rigorously assess utility adherence to Rule 21 requirements.

- The utilities provided data responses that varied in format file types and comprehensiveness. In some cases, Guidehouse pursued follow-up sampling requests for a limited number of projects to better understand the nature of available data.
  - PG&E provided a raw extract of its internal interconnection tracking database, which contained all project types with over 1,000 data fields. The extract allowed the team to identify the majority of the fields requested but required considerable effort to process than originally anticipated.
  - SCE provided spreadsheets for NEM and non-NEM projects with 10 and 35 data fields, respectively. The team requested 45 additional fields for NEM projects and 24 additional fields for non-NEM projects in follow-up sampling requests.
  - SDG&E provided spreadsheets for NEM and non-NEM projects with 11 and 25 data fields, respectively. The team requested 45 additional fields for NEM projects and 24 additional fields for non-NEM projects in follow-up sampling requests. Fields related to SR and upgrades were not applicable to any SDG&E project.

- The data obtained from SCE NEM and SDG&E contained only in-service projects. PG&E and SCE non-NEM data included projects that were in-service, withdrawn, or were in progress.
- Data for project characteristic fields like project program type, technology type, and project status often had different values or formats for each utility, which made comparisons difficult. These inconsistencies stem from differences in utility processes, programs, or business practices, and are not straightforward to reconcile. Rule 21 requirements do not stipulate specific naming conventions or data architecture to maintain by the utility representatives. The research team made efforts to standardize categorization of information by leveraging definitions from utility representatives and considered remarks from stakeholders to produce an evaluation data dictionary.
- Some interconnection characteristics governed by Rule 21 are not often applied and are not applicable for the majority of identified projects under standard NEM or generally eligible for fast track. In particular, detailed studies like FS or DGS, upgrades, and cost envelope option data are applicable to only a small subset of projects. The datasets did not consistently provide a clear indication regarding which of the steps were applicable for any given project.
- For some portions of the interconnection process, the research team had limited or no data visibility. In some cases, this was because Rule 21 did not have established timeline requirements (in BDs) for these steps during the evaluation period. Additionally, only Rule 21 parameters were considered for this study, eliminating interconnection schedules and timelines related to other Electric Tariff Rules (i.e., Rules 2, 15, and 16) that govern system design enhancements and extensions, service planning, and load-only standards such special facilities.
  - Response times to inquiries, including general inquiries and pre-application reports, are not tied to specific applications or requests and were therefore not available on a per-project basis.
  - Timelines for design and construction of interconnection facilities or upgrades, commissioning, and utility inspections were not available for projects that required these steps after completion of engineering reviews and studies. Rule 21 did not include timeline requirements for these steps for projects in the 3-year study period, resulting in data for these steps not being tracked often.
  - The length of delays due to external parties or external factors like permitting were not tracked because they were out of both utility and customer control. IOUs are familiar with these potential externalities; however, site control and land use can lead to elongated processes awaiting responses from landowners or AHJs.

Recommendation: Data tracking and reporting should be standardized for ease of reporting and public use to enable benchmarking and comparison efforts. It is reasonable to achieve such guidelines within the informal forums already established or under a regulatory decision and should be streamlined to the greatest extent possible while respecting differences in implementation processes among the utilities.

The research team notes that additional tracking requirements were adopted by the Commission in September 2020 to improve timeline certainty (see D. 20-09-035 Issue 12 under R. 17-07-007). Discussions between Energy Division staff and the utilities will clarify the meaning of these requirements in the context of each utility's interconnection process and define streamlined methods of tracking and reporting that promote consistency. The following recommendations may inform these efforts.

- Each utility should use a similar method and format to provide per-project interconnection timeline data (as opposed to varying formats like comprehensive database extracts versus selected extracts in single spreadsheets). A standardized template for data reporting with clearly defined field names and data validation checks should be developed with utility input.
  - This should minimize the need for post-receipt processing of multiple files, follow-ups, or sampling, while promoting consistency across the utilities to the greatest extent possible.
- The reporting requirements should also include key project characteristic information like program type, size, project type, technology type, and project status for each record. These fields are important to understanding how timeline performance may vary across different types of projects and allowing parties to identify areas needing improvement.
- To promote consistency in the data collected, the reporting process should utilize drop-down values with agreed-upon terminology or other validation rules. Some information, like generation technology types when multiple technologies or paired storage systems are present, was reported differently by each utility in the data collected for this study.
- To achieve this, utilities may need to consider redefining certain aspects of internal business process manuals to absorb these changes. Migration into different hosting platforms and resources may be a likely outcome with additional costs for the utility associated with personnel responsibilities expanding to maintain these records in such recommended formats.

7.2 Project Population Characterization and Segmentation

The research team characterized and segmented the NEM and non-NEM project populations of each utility according to key characteristics such as program type (e.g., Standard NEM, Non-Export), project size, technology type, and the specific Rule 21 reviews or studies performed. The team summarized the project population relative to these characteristics on a per-project and an aggregate capacity basis.[18]

For each utility, the vast majority of projects by count were less than 30 kW, solar, and Standard NEM. Many other project types occurred in relatively small numbers and often accounted for a disproportionately large portion of aggregate capacity. During the characterization and segmentation process, the team identified several challenges with data structure, completeness, and consistency across the utility datasets.

[18] Sections 3.1 and 4.1 present complete project population results for NEM and non-NEM projects, respectively.

Finding: Project or program type data varied in detail across the utilities, and differences in program offerings and specific names differ for each utility.

- PG&E and SDG&E NEM data differentiated between program types like Standard NEM, NEM-A, and V-NEM while SCE data differentiated only between NEM-1 and NEM-2.
  - For both PG&E and SDG&E, the vast majority of projects were standard NEM. The next most common program types were NEM Multi-Tariff and Expanded NEM for PG&E and NEM Paired Storage for SDG&E.
  - The specific names used for variants or different versions of NEM programs differed based on the specifics of each utility's offerings and tariffs.
- Each utility indicated detailed non-NEM project types, but the naming conventions used varied. For PG&E, the research team classified the non-export, continuous uncompensated export, and export project types as non-NEM. SCE and SDG&E provided non-NEM datasets with NEM project types listed for some projects.
  - For PG&E and SCE, most non-NEM projects were non-export. For SDG&E, the majority of non-NEM project types were advanced energy storage export and advanced energy storage non-export.

Recommendation: Detailed project or program type data should be provided for each project, and of similar project type naming conventions should be standardized where possible.

- Data should include detailed project types for each project to identify non-standard NEM projects such as V-NEM, NEM-A, and SASH/MASH. These project types are inherently more complex than Standard NEM and often have unique application considerations that could contribute to differences in timeline performance. Additional detail could also be valuable for improving oversight and regulatory design in the future.
  - Requirements should provide flexibility for reconciling differences in the naming or treatment of different NEM programs between the utilities. Some permutations such as those for V-NEM and NEM-A differ by utility and could be clarified or combined depending on the level of granularity desired.
- Data requirements should confirm that records are properly categorized as NEM or non-NEM. If the apparent discrepancy in classification for SCE and SDG&E was the result of projects requesting interconnection under a NEM program but later changing to a non-NEM program, then the Commission should take steps to confirm that records that initially apply under one program type but change to a different type are appropriately identified and classified.
  - Requirements should promote consistency in the project types that are classified as non-NEM. To account for differences between the utilities, the requirements could include a list of allowed project type values or provide guidelines to map varying utility-specific values to a common set of values.

Finding: Project statuses other than in-service were included in some but not all datasets. The omission of non-in-service statuses limits this study. There are many other statuses for projects that are in progress.

- PG&E NEM data included 10 unique project statuses while SCE and SDG&E NEM data included only in-service projects.
    - For PG&E NEM, in-service projects were 97% of all projects by count but only 73% of aggregate capacity. Withdrawn projects were around 1% of all records by count and 13% of aggregate capacity. The withdrawal rate was significantly higher for non-standard NEM program types.
- PG&E non-NEM data included 7 unique and SCE non-NEM data included all project statuses while SDG&E non-NEM data included only in-service projects.
    - For PG&E non-NEM, withdrawn projects accounted for a much larger proportion of non-NEM projects—35% by count and 32% by aggregate capacity—than in the NEM population. For SCE non-NEM, withdrawn projects were 16% of non-NEM projects by count and 23% by aggregate capacity.

Recommendation: Data should be provided at a minimum for both in-service and withdrawn projects.

- Data for projects with another status, particularly withdrawn projects, is important to understanding the context of tariff performance, especially to the extent that timeline delays or upgrade cost burdens caused withdrawals. While there may be complications with reporting all project statuses such as those associated with projects in the middle of the review process, data at a minimum should include withdrawn projects in addition to in-service projects.
- Future requirements should consider identifying or linking records for withdrawn projects that are later resubmitted. Withdrawn projects may not accurately reflect lost or foregone capacity if some were resubmitted and approved as a new record.
- Given the large number of possible other statuses for projects at various stages of the interconnection process, it may be appropriate to exclude other statuses or map them to a simpler set of values.

Finding: For all three utilities, larger projects (those greater than 100 kW) comprised an outsized proportion of aggregate capacity relative to their count, especially for NEM.

- Projects less than 30 kW accounted for between 97% and 99% of NEM projects by count for all three utilities. However, these projects accounted for a relatively smaller proportion of aggregate capacity—53% for PG&E, 63% for SCE, and 75% for SDG&E.
    - For all three utilities, projects greater than 100 kW accounted for a significant proportion of aggregate capacity—42% for PG&E, 33% for SCE, and 20% for SDG&E—despite accounting for at most 1% of projects by count.
- The distribution of non-NEM project sizes skewed towards larger projects compared to the NEM populations. Projects less than 30 kW accounted for only 42% (PG&E), 20% (SCE), and 24% (SCE) of non-NEM projects by count and 0.2% (PG&E), 1.2% (SCE) and 1.2% (SDG&E) of aggregate capacity.
    - Projects greater than 100 kW accounted for a vast majority of aggregate non-NEM capacity—97% for PG&E, 99% for SCE, and 96% for SDG&E.

Recommendation: It may be appropriate to use size-weighted results in future studies rather than count-weighted results.

- To establish a baseline of performance in this evaluation, the research team weighted timeline results for all projects equally regardless of size. The most common project types (e.g., small solar NEM) performed well overall.
- In the future, weighting by size rather than count would shift the focus to larger projects that contribute disproportionately to aggregate capacity and are more likely to have extended timelines.

Finding: Project technology types were reported differently in the datasets, which complicated the identification of systems with multiple technology types.

- In the PG&E and SDG&E NEM datasets, storage appeared in the main technology type field, but it was not clear which were standalone or paired storage systems. In the SCE NEM dataset, the data included a separate field which flagged whether the project consisted of a storage system, and these all appeared to be paired storage systems.
  - For all three utilities, NEM datasets were dominated by solar projects. The small proportion of non-solar projects included primarily storage but also very small numbers of many other technologies.
- Similarly, the PG&E and SDG&E non-NEM datasets listed storage in the main technology type field. The SCE non-NEM dataset included multiple technologies in the technology type field and their individual capacities when relevant, which allowed the research team to identify many unique technology combinations.
  - For all three utilities, storage projects accounted for a majority of non-NEM records by count. On an aggregate capacity basis, solar and other were the largest categories for PG&E and SCE while storage and other were the largest for SDG&E.

Recommendation: Data for facility technology type(s) should be consistently reported to provide a comprehensive understanding of on-site technology combinations and storage configurations.

- Future data requirements should confirm that all reported projects have a listed generation technology to avoid “unknown” classifications and encourage consistency by using agreed-upon dropdown values and mappings.
- Data should clearly distinguish between paired storage and standalone storage systems.
- Requirements should provide flexibility for reporting technology types when an interconnecting project consists of multiple technologies or when the interconnecting project is an addition to an existing facility. In these cases, the existing technology type(s) and capacity should also be reported.

- Datasets should include validation mechanisms to check that reported technology types are consistent with project types (e.g., to check that projects interconnecting under NEM fuel cell do not have non-fuel cell entries in the technology type field).

Finding: The specific Rule 21 reviews and studies performed[19] were not clearly apparent for each project. The research team used other timeline-related data fields to determine what reviews or studies were performed and understand which timeline steps were applicable to each project.

- For PG&E, the reviews and studies performed could be clearly determined for around 98.5% of NEM and 75% of non-NEM projects. The vast majority of both NEM and non-NEM projects underwent only IR. SR and SIS occurred less often and usually for larger projects. FS and DGS detailed studies were rare.
- The full SCE NEM data did not include fields related to reviews or studies performed. Among the sample of 85 projects, one project underwent both IR and SR while the rest underwent only IR. In the SCE non-NEM dataset, the reviews and studies performed could be clearly determined for around 95% of records. Around 84% of these required only IR and around 13% also completed SR. The remaining 3% of projects required SIS, and only one required FS.
- For SDG&E, all NEM projects required only IR. In the cleaned non-NEM dataset, almost all projects required only IR. No projects completed SR and only one required SIS.

Recommendation: Data should include fields that clearly indicate whether each review or study was performed to allow identification of which processes and timeline requirements applied to each project.

- Data should include binary (true/false) fields that indicate whether IR, SR, SIS, FS, and DGS were completed for each project. This would reduce uncertainty associated with using fields with dates or lengths of time for certain processes to identify which reviews or studies were required.

7.3 Rule 21 Timeline Performance

The research team conducted timeline analyses to determine how well interconnecting projects have adhered to the timelines under Rule 21. While Rule 21 specifies dozens of specific steps and timeline requirements, the data request focused on a specific set of key steps from Sections E and F of the tariff. The team conducted the following areas of analysis based on what was possible with the data from each utility that varied in comprehensiveness and format.

- First, the team analyzed a select set of key steps in the interconnection process, including application validation, IR, SR, SIS, and GIA execution.[20]
    - Section 7.3.1 below summarizes results for NEM projects.

[19] This refers to the engineering reviews and screens described in Sections F and G of Rule 21: initial review (IR), supplemental review (SR), system impact study (SIS), facilities study (FS), and distribution group study (DGS).

[20] Sections 3.2 and 4.2 present full key tariff step timeline results for NEM and non-NEM projects, respectively.

- Section 7.3.2 below summarizes results for non-NEM projects.
- The team also analyzed these results for subsets of projects based on project size and technology type to identify differences or trends in performance. Section 7.3.3 below summarizes results for this additional analysis.

- Second, the team analyzed the total time from application submittal to PTO to provide a holistic picture of the total time a project took to complete the interconnection process. Section 7.3.4 below summarizes the results.[21]

Each subsection includes key findings related to these specific analysis areas. However, the overall timeline analysis led to the following main finding and recommendation.

Key Finding: Timeline performance was best for projects or key tariff steps that were more common, routine, or even automated like small solar Standard NEM projects and steps for application validation and IR. Conversely, steps or projects that are less routine like SR and SIS, large projects, and non-NEM projects had mixed timeline performance. For many of these more infrequent steps or project types, the research team had limited data in this evaluation.

Key Recommendation: Future tracking and evaluation efforts should focus on particular steps or projects that exhibited weaker timeline performance, occurred relatively infrequently, and/or were not robustly assessed in this study due to limited data visibility. This includes projects sized greater than 100 kW, non-NEM projects, and steps for SR, SIS, FS, DGS, and upgrades.

7.3.1 NEM Key Tariff Steps

Table 118 summarizes timeline results for the key timeline steps analyzed for NEM projects.

Finding: The key NEM timeline steps analyzed and the number of records analyzed in each step varied among the utilities depending on the available data and applicability to the project population.

- All NEM timeline analyses for SCE relied on the sample set of 85 projects. The sample was too small to fully represent of the subpopulation of larger projects, non-solar projects, and projects that required reviews or studies beyond IR.
- A number of steps for SCE and SDG&E were not analyzed due to lack of data. By contrast, the comprehensive database extract provided by PG&E allowed for analysis of all key steps.
- Steps related to SR and SIS were not applicable to SDG&E because no projects in the NEM dataset of in-service projects required SR or SIS.

[21] Sections 3.3 and 4.3 present total time results for NEM and non-NEM projects, respectively.

Table 118. Summary of NEM Key Tariff Step Timeline Results

Timeline Step*	PG&E Count	PG&E % Met	SCE Count†	SCE % Met	SDG&E Count	SDG&E % Met
Expedited 30-day provision for NEM projects	185,908	96.3%	82	90.1%	71,250	99.1%
Time to validate application	188,737	86.7%	85	96.3%	67,954	97.4%
Time to notify customer of application deficiencies	58,051	83.9%	47	90.4%	Not analyzed‡	
Time to respond to notification deficiencies	30,026	61.0%	25	93.7%	Not analyzed‡	
Time to complete IR	188,680	96.9%	85	100%	Not analyzed	
Time to complete SR after IR	331	66.8%	1	Met§	Not applicable**	
Time to complete SIS after DSA Execution	32	34.4%	Not analyzed		Not applicable	
Time to complete SIS after IR or SR	150	95.3%	Not analyzed		Not applicable	
Time to send GIA to customer after IR or SR	2,168	82.3%	85	97.9%	Not analyzed	
Time to send GIA to customer after SIS	53	90.6%	Not analyzed		Not analyzed	
Time for customer to execute GIA	1,711	74.9%	85	89.1%	Not analyzed	

* See Table 14 (in Section 2.3.2.2) for the tariff-derived timeline requirements for each step.

† All timeline analysis for SCE NEM were based on the sampled dataset of 85 projects. The inability to obtain a fully representative set of timeline data was a major limitation of this evaluation.

‡ Not analyzed means that the analysis was not performed due to missing or incomplete data.

§ Met indicates that the single project for which the timeline analysis was conducted met the timeline requirement. Because the analysis population was only one project, a percentage result is not shown.

** Not applicable means that the step was not relevant to any project in the project population

Key findings related to NEM timeline performance for the key steps in Table 118 include the following.

- PG&E NEM timeline performance for the key steps analyzed ranged between 34% and 97%. The steps with the highest adherence rate were the expedited 30-day NEM provision, completing IR, and sending a draft GIA to the customer after completion of reviews or studies. The steps with the lowest adherence rate were responding to deficiency notifications, completing SR, and completing SIS after DSA execution. SR and SIS do not occur for most projects but are often delayed when they do occur.
- SCE NEM timeline performance could not be robustly assessed because timeline analyses could only be performed for the 85 sampled projects. Among the sampled projects, adherence rates for the key steps analyzed were around 90% or greater. The sample did not include projects requiring SR or SIS, so these steps were not assessed.
- SDG&E NEM timeline performance was only assessed for two steps: the expedited 30-day NEM provision and the time to validate the application. Data needed to assess other

timeline steps was unavailable or not applicable. However, the steps that were analyzed had very high adherence rates and there was generally little indication of delays.

7.3.2 Non-NEM Key Tariff Steps

Table 119Table 112 summarizes timeline results for the key timeline steps analyzed for non-NEM projects.

Finding: The key non-NEM timeline steps analyzed were more consistent across the three utilities compared to the NEM timeline analysis because SCE and SDG&E provided more fields for non-NEM projects.

- For PG&E, the time to complete SIS after IR or SR step was not applicable to any project. One non-NEM project completed SIS, but it did not complete IR or SR.
- For SCE, the time to complete SIS after DSA execution step was not analyzed because the data did not include DSA execution date; DSA execution date was not requested in the data request.
- For SDG&E, the time to resolve application deficiencies and the time to complete SIS after DSA execution steps were not analyzed; data required was not requested in the data request. The time to complete SR step was not applicable to any project.
- The non-NEM datasets included far fewer projects than the NEM datasets for each utility, so the count of projects analyzed for each timeline step are relatively small.

Table 119. Summary of Non-NEM Key Tariff Step Timeline Results

Timeline Step*	PG&E Count	PG&E % Met	SCE Count†	SCE % Met	SDG&E Count	SDG&E % Met
Time to validate application	144	17.4%	911	25.0%	133	82.7%
Time to notify customer of application deficiencies	311	98.4%	122	55.7%	Not analyzed†	
Time to respond to notification deficiencies	143	49.0%	65	58.5%	Not analyzed	
Time to complete IR	131	34.4%	685	43.1%	132	72.3%
Time to complete SR after IR	11	27.3%	108	50.0%	Not applicable‡	
Time to complete SIS after DSA Execution	1	Met§	Not analyzed		Not analyzed	
Time to complete SIS after IR or SR	Not applicable		15	93.3%	1	Met
Time to send GIA to customer after IR or SR	101	76.2%	403	45.2%	127	96.9%
Time to send GIA to customer after SIS	1	Met	8	100%	1	Met
Time for customer to execute GIA	82	84.1%	408	80.6%	129	38.8%

* See Table 14 (in Section 2.3.2.2) for the tariff-derived timeline requirements for each step.
† Not analyzed means that the analysis was not performed due to missing or incomplete data.
‡ Not applicable means that the step was not relevant to any project in the project population.

§ Met indicates that the single project for which the timeline analysis was conducted met the timeline requirement. Because the analysis population was only one project, a percentage result is not shown.

Key findings related to non-NEM timeline performance for the key steps in Table 119 include the following.

- For PG&E and SCE, the step with the lowest adherence in the table was the time to validate the application relative to 10 BD. This is an indication that most applications had deficiencies that took extra time to resolve, which pushed the time to validate the application beyond 10 BD as allowed by Rule 21.
- PG&E timeline performance for other key steps ranged widely between 27% and 98%. The steps for sending deficiency notifications and GIA execution had the highest adherence rates. The steps for completing IR and SR had the lowest adherence rates.
- SCE non-NEM timeline performance for other key steps ranged between 43% and 100%. The steps for completing SIS and sending a draft GIA to the customer after completion of SIS had the highest adherence rates. The steps for completing IR and sending a draft GIA to the customer after completion of IR or SR had the lowest adherence rates.
- For SDG&E, adherence to the 10 BD benchmark for application validation was higher than the other utilities, suggesting that application deficiencies are less common or more quickly resolved. Adherence rates for other key steps ranged between 39% and 97%. The step for sending a draft GIA to the customer after completion of IR or SR had the highest adherence rate while the step for the customer to execute the draft GIA had the lowest adherence rate.

7.3.3 Timeline Performance by Project Size and Technology Type

The research team also broke down results for each timeline step by project size and generation technology type categories. Assessing at this additional level of granularity allowed the team to assess whether projects of a particular size or technology are delayed more often than others.

Key findings for the timeline performance of NEM projects based on size and technology include the following.

- For PG&E, the adherence rate for a number of timeline steps was lower for larger projects than for small projects. In particular, adherence rates for the NEM 30-day provision and the time to validate the application, time to complete IR, time to complete SR, and time to send draft GIA steps were noticeably lower for projects greater than 30 kW than projects less than 30 kW. For these steps, delays are more common for larger projects.
  - The adherence rate for these timeline steps also tended to be lower for non-solar projects than for solar projects, especially for the NEM 30-day provision and the time to validate the application and time to complete IR steps. However, the relatively small number of non-solar projects often led to small sample sizes, which limits the ability to make strong conclusions.
- For SCE, the limited number of sampled NEM projects prevented drawing strong conclusions about the relative timeline performance of smaller versus larger projects and

solar versus non-solar projects. Adherence rates were lower for larger projects in many steps, but the small sample size of 10 projects greater than 30 kW did not allow for statistically significant conclusions about this trend.

- For SDG&E, timeline adherence rates for larger projects were lower than smaller projects for the two steps analyzed, but this trend was less pronounced than what was observed for the other utilities. For these two steps, there was no statistically significant difference in the adherence rates for solar and non-solar projects.

Finding: Non-NEM projects did not exhibit consistent differences in timeline performance for projects based on size or technology type, unlike NEM projects. The non-NEM project populations are less skewed towards projects of any particular size or technology type.

7.3.4 Total Time from Application Submittal to GIA or PTO

The research team performed a high-level analysis of the total time for interconnection from application submittal to GIA execution or PTO to gain a broad understanding of the total time a project took to complete the interconnection process.

Finding: Across all three utilities, the most common project types tended to complete the entire interconnection process from application to PTO far quicker and within the required timelines far more often that other projects.

- Across all three IOUs, small NEM projects completed the interconnection process quicker and within the required timelines more often than larger projects. This is also true for NEM solar projects compared to other technology types and NEM projects that required only IR compared to those that required additional reviews or studies.
- For the subset of non-NEM projects larger than 100 kW and non-NEM non-solar projects, the total time spent in the interconnection process was similar to the full non-NEM population for each utility. This makes sense because non-NEM populations varied in size and technology type more than NEM populations.

7.4 Study and Upgrade Costs

The evaluation also requested data to analyze questions related to estimated and actual cost components of the interconnection process under Rule 21 such as study costs, upgrade costs, and the cost envelope option. The quantitative data request included a number of fields related to cost certainty with the data received summarized below. For projects with established cost allocation aligning to specific tariff requirements, the research team derived deposit and fee assumptions from the corresponding interconnection track milestones by utility. Further, the team confirmed cost information stored in GIA forms with corroborating data fields from the quantitative data requests.

Finding: The team identified the most cost-related data for PG&E, but fields for projects triggering upgrades and projects with estimated or actual costs were inconsistent. SCE and SDG&E, through sampling efforts, provided limited cost data.

- The research team identified fields in the PG&E data for estimated and actual customer, utility, and total costs for interconnection facilities and distribution upgrades. The team also identified separate fields indicating whether projects required upgrades. The data subsets for upgrades, estimated costs, and actual costs only partially overlapped, and most projects flagged as requiring upgrades did not have estimated or actual cost data.

- Around 770 projects (0.4% of all projects) were flagged as requiring upgrades. Expanded NEM was the most common project type by count, but V-NEM, NEM-FC, and RES-BCT triggered upgrades more frequently than the average rate of 0.4%. The upgrade rate clearly increased for larger projects, which is intuitively sensible as larger projects are more likely to exceed existing system limits.
- The team identified 30 records with estimated costs, nine records with actual costs, and four records with both estimated and actual costs. Among these four sets, there were examples of estimates both under- and over-estimating actual costs. In most cases, costs were mostly or completely identified for interconnection facilities rather than distribution upgrades. However, distribution upgrades contributed a considerable portion for several projects with relatively large total estimates prior to construction activities.
- Cost data was not present for most PG&E projects marked as requiring upgrades and was present for some projects not marked as requiring upgrades.

- SCE did not include any cost fields in the initial NEM and non-NEM data files; however, the research team requested data for estimated and actual detailed study and upgrade costs in both the NEM and non-NEM samples. Only one of the 85 sampled NEM projects had estimated cost data for distribution upgrades. Six projects in the non-NEM sample had estimated detailed study costs paid for SIS or FS, which equaled the flat fees listed in the tariff, and four had estimated costs for distribution upgrades. SCE did not provide actual costs for upgrades in the data request submission.

- SDG&E provided data on customer SIS study costs paid, which was equal to the flat fee specified in the tariff. SDG&E staff confirmed that no in-service projects in the 3-year study period required distribution or transmission upgrades. Therefore, fields related to estimated and actual upgrade costs were not applicable.

Recommendation: For the purposes of continued CPUC-led evaluations, IOUs should better track associated cost expenditures for performed interconnection-related upgrades within project files and portfolios to expedite data collection activities and deliver more complete datasets in the future.

7.4.1 Cost Certainty and Customer Impact

The research team also collected cost-related information from qualitative interviews with utilities and developers to understand estimated and actual interconnection costs and timelines associated with cost certainty. The questions surrounded the nature of interconnection facility requirements, upgrades, known mitigations, and other assorted interconnection customer experiences. The utilities are positioned to make informed engineering decisions to modify their electrical facilities and assets as a result of engineering reviews, studies, and necessary screens. They maintain the responsibility to increase line capacities and balance voltage levels, where identified, to ensure new DERs do not adversely impact the distribution network and to maintain safe and reliable delivery of electricity to customer.

This subsection highlights areas where improvement is needed and applauds effective administration of SNEM, non-export, and general fast track interconnection activities among IOUs.

Finding: Costly distribution system upgrades are rare and, when identified, are often avoided through project redesign/downsizing or results meeting discussions on alternative mitigations.

- Typical upgrades and mitigations include system modifications made to transformers, reclosers, telemetry, service line extensions and access routes. Costs for upgrades vary depending on construction needs. For smaller projects, customers have experienced cost estimate ranges from the thousands to tens of thousands.
    - It is uncommon for projects < 1MW to trigger a mitigation or upgrade valued at $1 million or higher. A system redesign or withdrawal would most likely occur to avoid such financial upsets.
- Substation equipment upgrades are uncommon. Customers tend to avoid these costly upgrades by downsizing or redesigning their project. Upgrades often exceed the customer's facility's total cost-of-ownership.
- Developers shared project examples where PG&E identified excessive upgrades attributed to the DER's system impact, which resulted in informal resolution engagement to understand the proposed mitigations. Developers also noted that billing practices within PG&E are likely to improve over the next year due to upfront invoicing. At times, site inspections and visits from service planning reveal differing results from the SIS, which can alter the original estimate and require modifications to ensure distribution network stability. Interviews suggest this is less common with SCE and SDG&E.
- Notably with PG&E, significant upgrades can hinder potential credit generation or additional benefits for customers as they await PTO status. They must also maintain financial assurance through a security deposit in the form of a letter of credit and an escrow account, which can financially strain a planned project. PG&E also requires applicants to make continued deposits into the independent escrow account during the interconnection process despite raised issues or disputes.
    - Four developers associated with NEM-A projects opined on the need to refine true up billing processes, noting drawn-out disputes. Developers look forward to discussing these issues in future stakeholder engagement forums.
- Material modifications to projects are both driven by external constraints and utility-identified mitigations.
    - These are often simple changes that are more easily processed through SCE's online portal, as opposed withdrawing and restarting the interconnection timeline. The research team captured disagreement with this claim from another developer with ample experience interconnecting into SCE's service territory. The developer stated that physical handoffs regarding material changes to the DER design cause significant deficiencies and delays despite the portal's continued refinement of features.

- Developers noted that PG&E is often willing to work directly with applicants on design adjustments, activities to prevent the need for withdrawal and re-application processes, and upgrade disputes. However, representatives are difficult to contact via email or phone. An average response window of three to five days causes frustration and unnecessary delays.

Recommendation: IOUs have successfully used harmonized approaches to forecast triggered mitigations for applicants. However, improving precision of invoicing and applicable impact study results could help prevent excessive upgrades.

- Across IOUs, interconnection cost estimates are generally reasonable, but cost discrepancies do exist for distribution system upgrades.
  - Stakeholders feel that PG&E DER impact studies are excessively costly due to onerous interconnection processes and delayed accrual of benefits from customer systems.
  - Developers decried the unpredictability of proposed devices triggering an upgrade, which amounts to a lottery, rather than a queueing, process. The ICA provides developers with the foresight necessary to plan larger portfolios, but they lack insight into the current utility mitigations processed in concert with their queued projects.

Finding: Delays associated with cost methodology timeline requirements occur most frequently during the construction phase.

- The study and design/construction phases of the interconnection process exhibited cost of interconnecting uncertainty**.** Necessary upgrade construction is at the discretion of each IOU and guided by engineering reviews and facility and impact studies.

Recommendation: Stakeholders desire more precise invoicing, billing component and true up education, and itemization of anticipated costs. CPUC programmatic changes have the potential to expedite this process.

- Stakeholders also conveyed that applicants may need to withdraw or reduce system capacity of and otherwise financially viable projects to accommodate significant upgrade cost allocations. This can significantly hinder grid tied DER project integration.
- Stakeholders acknowledge improvement to cost certainty over the study period and look forward to future clarity in project interconnection invoicing. Issues mostly result from the facility's surveyed distribution grid impact. Resulting modifications can cause significant delays and deter otherwise financially viable projects.
- Stakeholders seek improvements to post operational permissions billing and true up procedures.

- Several developers recommend codifying timeline requirements through R. 17-07-007 and setting response window guidelines and/or requirements during the design and construction phases. This would increase certainty for interconnecting customers.

Finding: Most developers do not find the CEO to be an applicable offering as internal cost estimators and the utility Unit Cost Guides provide sufficient itemization to forecast anticipated expenses. However, developers agree that customers lack awareness of this option, which suggests additional public education may be beneficial.

- The CEO does not frequently provide cost certainty to interviewed stakeholders. IOUs identified only one project that elected the CEO and also reached PTO across almost 400,000 surveyed projects.

- Customers are often discouraged to investigate the CEO for cost certainty particularly when seeing the deposit amount of $2,500. Smaller projects do not benefit from the CEO while larger projects are often facilitated by experienced developers and contractors.

  - Nascent developers and individual applicants may be at a greater disadvantage because they have relatively less experience navigating Rule 21 programmatic changes than more experienced developers and contractors.

Recommendation: Additional customer education is warranted to better represent the conditions where this effort is most effective in streamlining the interconnection process and providing cost certainty.

- The CEO is most useful for projects larger than 1 MW, but interviewers identified few examples of its application and a lacked awareness of the specific requirements among smaller developers.

- Developers recommended continued education and better navigational tools. In particular, they suggested depicting typical project examples to help applicants make informed decisions when entering the queue.

7.5 Business Practices and Processes

This final section discusses the overarching recommendation targeting administrative and operational practices that may be considered to alleviate interconnection issues and disputes over time. Guidehouse collected process improvement suggestions from developers that could be achieved through utility procedure refinements, public forum discussions, or regulatory changes. These process improvement suggestions follow the recommendation statement on page 136.

Finding: IOU tools and systems vary but developers generally found them user-friendly. However, the customer service experience, especially related to point-of-contacts for project follow-ups, varies.

- PG&E has tracking and coordination issues for interdepartmental communications when projects move from one team to another. Site inspections for projects under 10 kW are also often omitted or performed. Assigned project representatives are often overloaded with various projects, which increase in complexity over time. Sufficient lead-time for customer responsible remedies are also a concern.

- SCE reportedly has issues with coordination with field engineering teams. Reporting disconnects across departments mean applicants need to continually reeducate and update SCE representatives on project and tariff implementation details.

- SDG&E's direct interconnection team operates and responds to inquiries and follow-ups within a 24-hour window, on average. It can experience similar disconnects in relayed updates when moving the project along the interconnection track.

- Application portals vary in functionality and usefulness, but developers find them all to be generally user-friendly and appreciate the continued improvements made over the last year and those anticipated for 2021.
  - Systems have improved over the past few years, and new systems are being rolled out at PG&E and SCE.
  - SCE's GIPT is well-regarded.
  - PG&E's initiative in migrating portals into a singular access point is also appreciated.
- Points of contact vary depending on project type and complexity for all three utilities.
  - Simple projects (generally Standard NEM) have shared inboxes or are routed through general call centers. This results in a lack of direct engagement past the point at which an issue is raised.
  - Project applicants are disgruntled by the three to five-days often required to reach a representative to discuss discrepancies or disputes.
  - Non-standard NEM, non-NEM, large projects, or projects triggering upgrades generally have dedicated points of contact.
- Handoffs between assigned project managers or utility departments and subsequent communication issues are common complaints for larger, non-NEM projects with PG&E and, to a lesser extent, SCE.
  - SDG&E interconnection representatives are generally recognized as providing adequate and timely customer service.
- Experiences with communication and customer service for general interconnection process inquiries are similar to the timeline delays experienced when raising disputes.
  - Utilities have different inquiry response processes based on project type and/or size. In general, it is much more challenging to reach a utility representative at PG&E versus SDG&E and SCE.
  - Developers appreciate having dedicated managers, but experience problems with rotated assigned project managers, not receiving notification of a change, and inconsistent communication after handoffs.
  - Developers spoke highly of communication from SDG&E. They expressed the most difficulties reaching out to resolve issues with PG&E.

- Developers spoke to the usefulness of working groups and stakeholder sessions in spurring improvement over time and raising important issues for proactive discussion.
  - Developers see room for improvement in turning discussion and investigation reports into actionable initiatives or programmatic changes.

Recommendation: All IOUs should improve educational efforts for small developers and individual customers and develop dynamic online portals for all types of projects. The CPUC should work with IOUs to develop and conduct customer service surveys and make IDFs and working groups more action oriented with implementation roadmaps.

- Seize opportunities to assess and improve customer service and consistency through structured and recurring feedback solicitation.
  - CPUC-led customer satisfaction surveys across all utilities can readily identify problem areas and encourage consistency of service where possible given differences in utility size, footprint, and organization.
  - Technologies are evolving and interconnection requests are increasing. This can prompt necessary enhancements and refinements to both regulatory guidance and utility processes.
- Target educational efforts to smaller developers or individual customers who may not receive as much attention or are less familiar with strategies for avoiding project deficiencies and timeline delays.
  - Favorable mention was given to the development of highlighted guides, example interconnection scenarios, FAQ documents that are routinely updated, tutorials, webinars, and wizard features to guide applicants throughout the process.
- Implement dynamic portal-based application processes for all process and project types and use portals to guide applicants to the correct application process, track project status, and provide notification of issues.
  - Consider implementation of APIs with portals to save time and resources and standardize data collection to better align to the 77 applicable data fields discussed in detail throughout this report.
- Limit frequency of changes or coordinate changes to the interconnection process to avoid confusion.
- Mitigate instances of overloaded assigned project representatives with cost-effective, prudent solutions including third-party contractors, additional supporting staff roles, seasonal responsibilities for influx periods, or other means of restructuring data repositories to better record project details.
  - Utilities should consider undergoing routine resource sufficiency assessments to address the gaps in performance across differing departments engaged with the interconnection process. Further, procedural documents for internal business processes will provide accountability and an avenue for IOUs to revisit implementation processes and customer satisfaction.

- Improve existing stakeholder mechanisms (IDF, working groups) to move from discussion to action and encourage parallel avenues of refinement through prioritization of intermediate and long-term interconnection concerns.
- Changes to the tariff have been historically overwhelming and confusing for developers and the utility customer bases.
  - Utilities should consider undergoing routine resource sufficiency assessments to address the gaps in performance across differing departments engaged with the interconnection process. Further, procedural documents for internal business processes will provide accountability
- Giving appreciation to the tremendous efforts undertaken over several years towards continuous improvement, developers request more visuals and comparison graphics of utility practices.
  - Documents, guidelines, and practices manuals are very detailed and technical, often complicating the process for applicants seeking answers for their design needs. Developers appreciate the published presentations and diagrams depicting the expected timeline to operate and encourage similar publications as the program evolves.
- Build an implementation roadmap to forecast improvement and avoid the need to repeatedly raise issues.

Appendix A. Quantitative Data Request

This appendix lists the 77 fields requested in the quantitative data request. The research team requested these fields from each utility for projects that applied or received PTO between July 2016 and June 2019.

Category: Interconnecting Project (25 fields)

- Queue Number or Project Number (alias)
- Pre-Application Information Submitted (Y/N)
- Application Submittal Date
- Current Project Status
- Application Deficiencies (if any)
- Holds put on the process (identify)
- Project Technology Design (e.g., solar, storage, wind, solar plus storage, expansion, complex distributed energy resources, etc.)
- Project System Size (Generation Capacity/Export)
- Date of Completed Application Notice
- Program Applicability (e.g., Standard NEM, NEM2, NEM expansion, Rule 21 Non-Export)
- Export Status (e.g., Export/Non-Export/Continuous/Limited)
- Date Modifications Requested (if any)
- Required Rule 2, Rule 15, or Rule 16 application/activities (identify which, if any)
- Fast Track / Detailed Study Track
- Supplemental/Additional Reviews (Identify, if any)
- Technical Screen Results (e.g., Pass Q/Fail R, Pass R, Pass both)
- Distribution Group Study Applicability
- Date Received PTO
- Cost Envelope Option Selected (Y/N)
- Date Cost Estimate Provided
- Latest Date of Payment Received Prior to Construction
- GIA Date Executed
- Date NGOM Installed
- Date of Commercial Operation
- Project Withdrawal / Moved into WDAT (Mark “X” if either case applies)

Category: Timelines (15 fields)

- Total time for Application process (application deemed complete, one-line diagram approved)
- Total Time during Initial Review
- Time between Initial Review and informing the Customer
- Total Time during Supplemental Review
- Time between Supplemental Review and informing the Customer
- Total Time during Detailed Study Phase
- Total Time until PTO (Or similar utility-specific milestone. Please identify term.)
- Estimated Time for Design Phase
- Estimated Time for Construction Phase
- Actual Time during Design Phase
- Actual Time during Construction Phase
- Response Time for Notifying/Communicating with Customer/Developer (List multiple entries if applicable)
- Customer Missed Milestone(s)
- Utility Missed Milestone(s)
- Outside Entity-Related Delays

Category: Utility and Customer Estimated Costs (8 fields)

- Total Costs Estimated for Utility
- Total Cost Responsibility (Customer) in GIA
- Interconnection Facilities Subject to Cost of Ownership (List multiple entries, if applicable)
- Interconnection Facilities NOT Subject to Cost of Ownership (List multiple entries, if applicable)
- Total Distribution Upgrades Required (List multiple entries, if applicable)
- Total Transmission Upgrades Required (List multiple entries, if applicable)
- Distribution Upgrade Cost by Item
- Transmission Upgrade Cost by Item

Category: Customer Actual Costs (24 fields)

- System Impact Study or Phase I Study (Choose, if applicable)
- Total Cost of System Impact Study or Phase I Study performed
- Interconnection Facilities Subject to Cost of Ownership (List multiple entries, if applicable)

- Interconnection Facilities NOT Subject to Cost of Ownership (List multiple entries, if applicable)
- Distribution Upgrades required during this step (List multiple entries, if applicable)
- Transmission Upgrades required during this step (List multiple entries, if applicable)
- Distribution Upgrade costs associated with this step (List multiple entries, if applicable)
- Transmission Upgrade costs associated with this step (List multiple entries, if applicable)
- Interconnection Facilities Study or Phase II Study (Choose, if applicable)
- Total Cost of Interconnection Facilities Study or Phase II Study performed
- Interconnection Facilities Subject to Cost of Ownership (List multiple entries, if applicable)
- Interconnection Facilities NOT Subject to Cost of Ownership (List multiple entries, if applicable)
- Distribution Upgrades required during this step (List multiple entries, if applicable)
- Transmission Upgrades required during this step (List multiple entries, if applicable)
- Distribution Upgrade costs associated with this step (List multiple entries, if applicable)
- Transmission Upgrade costs associated with this step (List multiple entries, if applicable)
- Pre-Application Report Fee
- Interconnection Request Fee
- Cost Envelope Fee (if applicable)
- Initial Review Fee
- Supplemental Review Fee
- Detailed Study Total Cost
- Total Costs for the Customer
- Rate (%) of the Income Tax Component of Contribution (paid by applicant, if applicable)

Category: Utility Actual Costs (5 fields)

- Total Costs Incurred by Utility
- Supplemental Review Incurred Costs
- Detail Study Incurred Costs
- Interconnection Facility/Upgrade Costs Incurred
- Administrative/Miscellaneous Costs Incurred

Appendix B. Quantitative Data Fields Received

This appendix outlines the quantitative data fields that each utility provided, including fields provided as part of sampling requests.

B.1 PG&E Data Files and Data Fields

As discussed in Section 2.1.1, PG&E provided a raw extract of an internal interconnection tracking database for the evaluated 3-year time period. As Table B-1 shows, this extract consisted of over 200 files and 1,000 fields across a number of categories. Many fields were not directly relevant to the data request, such as equipment technical specifications and party contact information. Also, many fields either had no data for any project record or had data for only a handful of records.

Table B-1. Summary of PG&E Data Files Received

PG&E Data Category	Number of Files	Number of Fields	Fields Extracted
Data Dictionary	1	-	-
Equipment Information	7	70	13
Generation Asset Information	9	83	0
Meter Information	4	54	0
Partner (Customer, Contractor, Facility) Information	4	64	0
Phase Information*	105	175	77
Project Information	10	119	34
Task (Timeline) Information	21	355†	160
Technical Screen Information	42	104	-
Total	**203**	**1,024**	**284**

* The phase data files included many miscellaneous fields related to project status, flagged issues, site/land information, account/meter information, and estimated and actual costs. Many of the fields had data for only a few projects or no projects. The research team primarily extracted fields related to estimated and actual upgrade costs.

† The task data included fields for 355 unique steps in the interconnection process, each with a start date and an end date. The research team extracted 160 of these fields that aligned with the tariff steps identified in Appendix D and used a subset of these for the timeline analyses.

The research team ultimately extracted 284 fields to use for the project population characterization, timeline, and cost analyses. These included fields that most closely matched the fields in the original data request, plus extra timeline fields that were not included in the data request, but which were identified in the research team's analysis of the Rule 21 timeline requirements (see Appendix D).

B.2 SCE NEM Data Fields

The research team initially received one SCE NEM file with 10 fields populated. Table B-2 shows these fields, which consisted primarily of basic project information. PTO date was the only timeline field received.

Table B-2. SCE NEM Initial Data Fields Received

SCE NEM – Initial Fields Received	Records with Data
Project ID	134,838
Technology Type	134,838
Total Nameplate (kW)	134,838
ZIP Code	134,838
Customer Class (Res, Com, etc.)	134,838
Battery (Y/N)	134,838
Battery kW	4,164
VNEM-NEMV	134,838
NEM Tariff	134,838
PTO Issue Date	134,838

Table B-3 shows the 45 fields requested for the sample of 85 SCE NEM projects. The sampling effort targeted fields related to project timelines and delays. However, many fields related to the independent study process, material modifications, and study and upgrade costs were not applicable for any project in the limited sample set.

Table B-3. SCE NEM Additional Fields Included in Sampling

SCE NEM – Sampled Fields	Records with Data
Known Outside Entity-Related Delays	85
Program / Request Type Selected	85
NGOM Being Requested? (Y/N)	85
Transfer to GICD (Y/N)	85
Interconnection Process Track	85
Application Submittal / Stamp Date	85
Date Application Deemed Complete	85
Date of Initial Review	85
Date Initial Review Report Provided to Customer	85
Date Customer Notified Utility it is Ready for PTO	85
GIA Date Executed	85
Date Executed GIA Returned by Customer	85
Date Interconnection Request Fee Received (if applicable)	57
Utility Missed Tariff Process Deadlines (list multiple, if applicable)	32
Customer Missed Tariff Process Deadlines (list multiple, if applicable)	30
No. of BD between receiving an inquiry and responding to the Customer / Developer (List multiple entries if applicable)	25
Date of Deficiencies Cured by Customer (list multiple if applicable)	23
Description(s) of Deficiencies in Interconnection Application/Request	23

SCE NEM – Sampled Fields	Records with Data
Date of Notice of Deficiencies sent to Customer (list multiple if applicable)	23
Actual Costs Incurred by Utility for Supplemental Review (if applicable)	2
Date Supplemental Review Fee Received (if applicable)	2
Date Draft GIA Provided to Customer	2
Estimated Cost of Distribution Upgrade(s) Provided to/Paid by Customer (if applicable)	1
Date(s) for Holds put on the process (identify at which step)	1
Date(s) for Holds Resolved	1
Date of Supplemental Review	1
Date Supplemental Review Results reported to the Customer	1
Estimated Cost of Transmission Upgrade(s) Provided to/Paid by Customer (if applicable)	0
Actual Costs Incurred for Distribution Upgrade(s) (if applicable)	0
Actual Costs Incurred for Transmission Upgrade(s) (if applicable)	0
Date Material Modifications Requested (if any; list multiple if applicable)	0
Date Material Modification(s) Made	0
Date of System Impact / Phase I Study (if applicable)	0
Date of Facilities Impact / Phase II Study (if applicable)	0
Material Modifications Requested (if any)	0
Date Technical Screen Results Provided to Customer	0
Date of System Impact / Phase I Study Results to Customer (if applicable)	0
Date of Facilities Impact / Phase II Study Results to Customer (if applicable)	0
Date Interconnection Financial Security Deposit Received	0
Actual Costs Incurred by Utility for Detailed Studies (if applicable)	0
Date Cost Estimate for Detailed Studies Provided to Customer (if applicable)	0
Total Detailed Study Costs paid by Customer (if applicable)	0
Total SIS/Phase I Study Costs paid by Customer (if applicable)	0
Total Facilities/Phase II Study Costs paid by Customer (if applicable)	0
Date Detailed Study Deposit Received (if applicable)	0

B.3 SCE Non-NEM Data Fields

The researched team received two SCE non-NEM files prior to sampling which contained the fields shown in Table B-4. These initial files included project and timeline information but little data on study or upgrade costs. The table also shows the incomplete and inconsistent nature of fields related to certain tariff steps. For example, the three timeline fields related to SR were populated for a differing number of projects: among the 113 records with data in the Date SR Results Reported to Customer field, only some also had data in the Date SR Fee Received (91) or Date of SR (94) fields.

Table B-4. SCE Non-NEM Initial Data Fields Received

SCE Non-NEM – Initial Fields Received	Records with Data
Project ID	1,029
Queued? (Y/N)	984
Technology / Prime Mover Type	1,029
Project System Size (MW)	1,029
Substation ID	1,029
Program / Request Type Selected	1,029
Export Status	984
Interconnection Process Track	1,029
Included in Supplement? (Response 2)	431
Current Phase	1,029
Date Issued PTO	400
Application Submittal / Stamp Date	1,029
Date Interconnection Request Fee Received	696
Date Envelope Option Requested	32
Date Cost Envelope Deposit Received	1
Date of Notice of Deficiencies sent to Customer	56
Date of Deficiencies Cured by Customer	49
Date Application Deemed Complete	921
Date of Initial Review	880
Date Initial Review Report Provided to Customer	695
Date Supplemental Review Fee Received	91
Date of Supplemental Review	94
Date Supplemental Review Results reported to Customer	113
Date Detailed Study Deposit Received	44
System Impact Study or Phase I Study Performed (Y/N)	984
Interconnection Facilities Study or Phase II Study Performed (Y/N)	984
Date of System Impact / Phase I Study	16
Date of System Impact / Phase I Study Results to Customer	11
Date of Facilities Impact / Phase II Study	1
Date of Facilities Impact / Phase II Study Results to Customer	1
Date Draft GIA Provided to Customer	458
Date Executed GIA Returned by Customer	657
IA Execution Date	431
IA Executed?	431
Actual In-Service Date	368

Table B-5 lists the 24 fields requested for the sample of 85 non-NEM projects. Sampled timeline fields included GIA execution date and descriptions of application deficiencies. The sample also included fields related to study and upgrade costs. Study cost data was applicable to a small subset of the sample population while upgrade costs were not applicable to any sampled project.

Table B-5. SCE Non-NEM Additional Fields Included in Sampling

SCE Non-NEM – Sampled Fields	Records with Data
Project ZIP Code (Requesting ZIP Code, if available, instead of Substation ID)	81
NGOM Being Requested? ("yes" / "no")	77
GIA Date Executed	69
Date Customer Notified Utility it is Ready for PTO	40
Description(s) of Deficiencies in Interconnection Application/Request	37
Utility Missed Tariff Process Deadlines (list multiple, if applicable)	35
Date(s) for Holds put on the process (identify at which step)	15
Date(s) for Holds Resolved	15
Customer Missed Tariff Process Deadlines (list multiple, if applicable)	15
Date Technical Screen Results Provided to Customer	7
Date Cost Estimate for Detailed Studies Provided to Customer (if applicable)	7
Total SIS/Phase I Study Costs paid by Customer (if applicable)	6
Estimated Cost of Distribution Upgrade(s) Provided to/Paid by Customer (if applicable)	4
Total Detailed Study Costs paid by Customer (if applicable)	2
Total Facilities/Phase II Study Costs paid by Customer (if applicable)	1
Date Material Modifications Requested (if any; list multiple if applicable)	1
Date of Distribution Group Study / Study Group (if applicable)	1
Actual Costs Incurred by Utility for Detailed Studies (if applicable)	1
Estimated Cost of Transmission Upgrade(s) Provided to/Paid by Customer (if applicable)	0
Actual Costs Incurred for Distribution Upgrade(s) (if applicable)	0
Actual Costs Incurred for Transmission Upgrade(s) (if applicable)	0
Date Interconnection Financial Security Deposit Received	0
Material Modifications Requested (types, if any)	0
Date Material Modification(s) Made	0

B.4 SDG&E NEM Data Fields

The SDG&E NEM data file included the fields shown in Table B-6. The fields included basic project details and timeline fields related to the expedited 30-day provision for NEM projects.

Table B-6. SDG&E NEM Initial Data Fields Received

SDG&E NEM – Initial Fields Received	Records with Data
Project ID	72,685
Application Submittal / Stamp Date	72,685
Date Application Deemed Complete	72,685
Date AHJ Inspection Received	72,683
Date of Deficiencies Cured by Customer	72,685
Date Issued PTO	72,685
Technology / Prime Mover Type	72,685
Project System Size (CEC-AC)	72,685
Project Location (ZIP Code)	72,685
Program / Request Type Selected	72,685
NGOM Being Requested? (Y/N)	72,685

As discussed in Section 2.1.2, SDG&E NEM sampling was limited to collecting a qualitative list of project issues from SDG&E's internal project tracking system. This is shown in Table B-7. Additional timeline and cost fields (such as those related to IR, SR, SIS, or system upgrades) were not included in the sampling request because they were either not readily accessible or applicable to any project.

Table B-7. SDG&E NEM Additional Qualitative Information Included in Sampling

SDG&E NEM – Sampled Information	Records with Data
List of Issues from Interconnection Database System	125

B.5 SDG&E Non-NEM Data Fields

The SDG&E non-NEM data file included the fields listed in Table B-8. The fields included basic project information and timeline fields related to application validation, IR, SR, SIS, and GIA execution.

Table B-8. SDG&E Non-NEM Initial Data Fields Received

SDG&E Non-NEM – Initial Fields Received	Records with Data
Project ID	133
Queued? (Y/N)	133

SDG&E Non-NEM – Initial Fields Received	Records with Data
Technology / Prime Mover Type	133
Project Location (ZIP Code)	133
Application Submittal / Stamp Date	133
Application Deemed Complete	133
Date Interconnection Request Fee Sent to Customer	131
Date Interconnection Request Fee Received from Customer	131
NGOM Being Requested? (Y/N)	133
Date of Initial Review	133
Date Initial Review Report Provided to Customer	133
Date of Supplemental Review	0
Date Supplemental Review Results reported to the Customer	0
Date Supplemental Review Fee Sent to Customer	2
Date Supplemental Review Fee Received from Customer	2
Date of System Impact / Phase I Study	2
Date of System Impact / Phase I Study Results to Customer	2
AHJ Inspection Date	131
Date of Deficiencies Cured by Customer	133
Date Draft GIA Provided to Customer	131
Date Executed GIA Returned by Customer	133
Approved Date/Executed GIA Date	133
Date Issued PTO	133
Project System Size (Gen Facility Net Capacity in MW)	133
Program / Request Type Selected	133

Like the SDG&E NEM sample request, the non-NEM sample request included collecting a qualitative list of project issues and deficiencies from SDG&E's internal project tracking system. The research team also requested study cost data for the two projects that completed SIS.

Table B-9. SDG&E Non-NEM Additional Information Included in Sampling

SDG&E Non-NEM – Sampled Information	Records with Data
(Qualitative Information) List of Issues from Interconnection Database System	46
(Data field) Total SIS Phase I Study Costs paid by Customer	2
(Data field) Actual Costs Incurred by Utility for SIS Phase I Study	0

Appendix C. Interview Guide and Questionnaire

C.1 Objective 1: Characterizing Compliance with Rule 21 Requirements

Topic: Utility Timelines

- Describe the Fast Track interconnection process timeline.
- Describe the Detailed Study interconnection process timeline. (Independent and Cluster Studies)
- Describe how Standard NEM projects are handled/processed, once receiving a complete application?
- What are the most common reasons for missed timeline milestones (delays) by the utility? (e.g., dates for providing information and study results to the customer)
- Which step(s) within the interconnection process caused the most delays?
- Which timeline milestones are most often likely to be affected by delays from the experience of the utility in aligning to required response times (e.g., technical review results, invoicing, dispute remedy, notice of application received, etc.)?
- Which timeline milestones were least often missed by the utility?
- Describe how the utility responds and follows up with customer or developer requests throughout the process.
- What are the average durations for completing a Fast Track application up until the design and construction phase?
- What are the average durations for completing a Detailed Study Track application up until the design and construction phase?

Topic: Customer Timelines

- About what percentage of interconnection customers provide the utility with deficiencies within the application, and what do those look like?
- What constitutes a delay that is out of the control of the customer or utility and how is that tracked if at all? (Provide examples of delays.)
- Which milestones were most often missed by the customer?
- Which milestones were least often missed by the customer?
- Please describe any situations where outside entities (relating to construction, permitting, environmental studies, etc.) led to a process delay.
- How frequently to customer timelines get delayed due to these outside factors and with what average duration? (e.g., high frequency, medium, low frequency)
- How often are processes slowed down due to lack of payment activities by the customer?

- What kind of guidance from the utility would help expedite the timeline for the Interconnecting Customer to provide related application information?

Topic: Cost Accounting

- How is the utility accounting for capital and O&M expenditures related to system upgrades, including customer-financed capital upgrades? Describe this procedure.
- Describe any situations where the utility required the Interconnecting Customer to pay for grid upgrades that were not necessary at that time but were likely to be required during the span of the GIA term.
- Describe any cases where the utility charged the Interconnecting Customer for grid upgrades that were necessary and planned irrespective of the project's interconnection?
- What are the common Interconnecting Customer-responsible upgrades that occur?
- What are the rare Interconnecting Customer-responsible upgrades that occur?
- What are the common Interconnecting Customer-responsible upgrades that may also have been part of an existing distribution plan?

Topic: Cost Envelope

- For Interconnecting Customers who elect the cost envelope option, are estimated and actual costs appropriately itemized in documentation provided by the utility to the customer?
- Have the interconnection requests that utilized the cost envelope option (if any exist) come in under or over 25% of their cost envelope estimate?
- Why are applicants not utilizing the cost envelope option as perceived by the utility?
- In what scenario is the cost envelope option best utilized by an Interconnecting Customer and how does the utility see this utilization rate increasing for future applications?
- What are the main perceived drivers for interconnection costs coming in over or under the 25% cost envelope?

Topic: Integration Capacity Analysis

- How is the utility using Integration Capacity Analysis maps since the 2018 release?

C.2 Objective 2: Business Practices and Tariff Implementation

Topic: Timelines

- Does the utility have internal processes in place to track, assess, and solve interconnection delays when they arise, and if so, how does this work?
- Does the utility provide the Interconnecting Customer with reasonably estimated timeframes for design and construction in the Generator Interconnection Agreement (GIA)? If so, how does it form these estimates?

- Does the utility adhere to construction, commissioning, and other timelines agreed to in the Generator Interconnection Agreement? If not, describe the conditions why.
- What challenges often arise during the Supplemental Review process that leads to a process delay? What are steps taken by the utility to address these?
- What challenges often arise during the System Impact Study process that leads to a process delay? What are steps taken by the utility to address these?
- What challenges often arise during the Interconnection Facilities Impact Study process that leads to a process delay? What are steps taken by the utility to address these?
- On average, what are the response times to customer inquiries/disputes and how is that tracked if at all?

Topic: Utility and Customer Costs

- Does the utility itemize bills for grid upgrades, enabling the customer to verify the accuracy or reasonableness of the charges?
- Does the utility require the customer to pay for certain mitigations when other, lower-cost mitigations may be sufficient? (e.g., are alternatives considered during respective engineering studies?)

Topic: Customer Service and Communication

- What standard operating procedures does the utility have in place for customer-oriented processes or customer experience tasks? For each identified customer experience task, what is the standard procedure? Which customer experience tasks are handled on a more ad hoc basis?
- How does the utility provide the same interconnection experience to similarly situated customers?
- How does the utility monitor themselves internally to ensure consistency of experience? Cite experience or steps that have been taken to ensure that all customers are treated the same regardless of location of interconnection.
- What is the average response time for the utility to respond to customer inquiries?
- What is the average response time for the utility to response to developer inquires (if different)?
- Does the utility provide a single point of contact for project-related communications? If so, how are those alignments arranged?
- What is the average time that the utility provides notice of inspection approval or receipt of funds?
- Does the utility’s online application portal support uploading large documents?
- Does the utility’s application portal provide a way to check project status? If so, for which types of projects?
- Does the utility maintain updated information and forms on its website? How often is that information updated? What triggers an update?

- How are requests for information from the utility to the applicant addressed and delivered?

Topic: Coordination between Departments and Offices

- When an interconnection request is handed off from one office or department to another, how is the transition managed and when is the customer notified, if at all?
- Is the customer provided a point of contact at all times during the handoff and interconnection process? How is this ensured?
- How do interconnection timelines vary across different regions within the utility's service territory? What are the main drivers for this?
- How is information shared and stored between the utility's central and field offices (if decentralized)?

Topic: Recordkeeping

- How does the utility keep records for all interconnections, including information on configurations and equipment installed?
- How do records transfer between customers when the utility customer of record changes? (e.g., a house sells to a new owner)
- Describe how utility engineers and representatives in the field gain access to the necessary records, diagrams, or databases to evaluate interconnection needs or effect solutions efficiently.
- How is the utility using interconnection data to analyze and respond to issues?

Topic: Workload Planning and Utility Accountability

- Is the utility utilizing General Rate Case approved budgets for interconnection department staffing and overheads? If so, what are the approved budgets, and how are they set?
- How does the utility handle interconnection applications? Describe these processes and practices.
- Describe how the utility takes into account expected growth in Rule 21 applications and processing needs when allocating staff and future resource planning.
- Does the utility contract with third parties to assist with dramatic increases in interconnection application submissions? If so, how are these events planned for and funded?
- Generally, how is the utility using interconnection data to do workload planning?
- What improvements has the utility implemented to improve the utility's ability to ensure compliance with the actual Rule 21 tariff (Provide any examples of internal compliance audits)
- What automation practices has the utility adopted to assist in data collection best practices and recordkeeping? Please describe your existing systems of data tracking and information processing.

- How does the utility ensure that all parts of it the Rule 21 tariff are being appropriately adhered to? (Provide any examples of checklists, compliance lists, or other mechanisms available that make sure staff is not overlooking anything)
- In years past, the Interconnection processes have had tremendous volume variations (interconnections per month) and also been primarily a paper-based system. In light of variations of quantity and also reliance on paper transactions, how has the utility ensured consistency in customer treatment and tariff-application across time/space/periods of high or low volume?
- Does the utility audit customers on whether they stay in compliance with Interconnection Tariff, (e.g., in Rule 21, you are not supposed to add to system size without notification to the utility). Identify if there any systems in place to monitor that compliance.
- How does the utility self-audit itself with regard to Rule 21 compliance? What checks and balances are in place to ensure compliance?

Appendix D. Summary of Rule 21 Timeline Requirements Identified

This appendix shows a full list of key interconnection steps and timeline requirements that the research team identified as described in Section 2.3.2.1. The timeline steps shown in Table D-1 are outlined in Section E (Interconnection Request Submission Process) and Section F (Review Process for Interconnection Requests) of Rule 21. Based on the data received from each utility, the research team selected a subset of these steps for the timeline analysis of key tariff steps (see Table 14).

Table D-1. List of Rule 21 Timeline Requirements Identified

Step Start	Step End	Tariff Requirement	Utility or Customer Action?
NEM: Application deemed complete, GIA execution, or AHJ inspection	PTO date	30 BD from latest field	Both
Application submittal	Application deemed complete	10 BD if no deficiencies	Utility
Application submittal	First notification of deficiencies	10 BD	Utility
First notification of deficiencies	Customer response to first notification of deficiencies	10 BD	Customer
Customer response to first notification of deficiencies	Second notification of deficiencies	10 BD	Utility
Second notification of deficiencies	Customer response to second notification of deficiencies	10 BD	Customer
Date application deficiencies cured	Application deemed complete	10 BD	Utility
Application deemed complete	IR results sent to customer	15 BD	Utility
IR results sent to customer	Draft GIA sent to customer	15 BD	Utility
SR fee paid	SR results sent to customer	20 BD	Utility
IR results sent to customer	SR results sent to customer	30 BD*	Both
SR results sent to customer	Post-SR options decision by customer	15 BD	Customer
Post-SR options decision by customer	Utility offer to schedule SR results meeting	5 BD	Utility
Scheduling of SR results meeting	SR results meeting date	Undefined	Both
SR results sent to customer	Draft GIA sent to customer	15 BD	Both
Detailed study deposit and application received	Completion of detailed study screens	20 BD	Utility
Detailed study screens complete	Utility offer to schedule scoping meeting	5 BD	Utility
Scheduling of scoping meeting	Scoping meeting date	Undefined	Both
Scoping meeting date	DSA tendered	15 BD	Utility
DSA tendered	DSA executed by customer	30 BD	Customer
DSA executed by customer	SIS complete date	60 BD	Utility

Step Start	Step End	Tariff Requirement	Utility or Customer Action?
IR results sent to customer	SIS complete date	150 BD†	Both
SR results sent to customer	SIS complete date	145 BD†	Both
SIS complete date	Post-SIS options decision by customer	10 BD	Customer
Post-SIS options decision by customer	Utility offer to schedule SIS results meeting	5 BD	Utility
Utility offer to schedule SIS results meeting	SIS results meeting date	Undefined	Both
SIS complete date	FS complete date	60 CD + 45 BD‡	Both
SIS complete date	GIA sent to customer	30 CD + 25 BD§	Both
FS complete date	GIA sent to customer	30 CD	Both
GIA sent to customer	Customer returns executed GIA	90 CD	Customer
Customer returns executed GIA	PTO date	Undefined	Both

* The time between IR completion and SR completion consists of more than one step. Upon notification of IR results, the 30 BD requirement consists of 10 BD for the customer to choose to move on to SR and 20 BD for the utility to complete SR and notify the customer of the results. The customer can also choose to have an IR results meeting prior to choosing to move on to SR, which could add 25 BD to the allowed time. SCE and SDG&E provided insufficient data to determine how often IR results meetings occurred. PG&E data indicated that IR results meetings occurred for only 0.02% of projects that completed IR.

† Data from SCE and SDG&E did not include the date DSA executed field. Therefore, the time to complete SIS was assessed using completion of IR or SR as the starting point. The 150 BD requirement between IR and SIS includes: up to 20 BD for the customer to choose to move on to detailed study (assuming no IR results meeting), 20 BD for the utility to complete detailed study technical screens, 5 BD to establish a scoping meeting date, 15 BD after the scoping meeting for the utility to provide the DSA, 30 BD for the applicant to execute the DSA, and 60 BD after execution of the agreement for the utility to complete and issue the SIS report. After SR, the customer has 15 BD to choose to move on to detailed studies (assuming no SR results meeting) instead of 20 BD, resulting in a total requirement of 145 BD.

‡ The requirement for completion of FS after SIS includes 60 CD after issuance of SIS report for the customer to make an initial posting of interconnection financial security followed by 45 BD for the utility to issue the FS report (assuming no material modifications are requested). The 45 BD for the second step increases to 60 BD if upgrades are required.

§ The requirement for sending the draft GIA to the customer after SIS includes 25 BD after issuance of the SIS report to reach a mutual agreement to waive FS (assuming no SIS results meeting) followed by 30 BD for the utility to provide the draft GIA to the customer.

Appendix E. Calculation of Requirements for Total Time for Interconnection from Application to GIA or PTO

This appendix outlines the calculation of the partial max and total max timeline requirements for the total time for interconnection analysis. As described in Section 2.3.2.3, the research team defined these requirements for projects based on their reviews or studies performed (track) with varying assumptions to provide a benchmark in assessing the total time from application submittal to GIA or PTO for a given project.

The **partial max** requirement reflects the total allowable time a project in a given track may take assuming the project faces no major issues or added steps that cause delays. In particular, it assumes no application deficiencies, no use of optional extensions, and no results meetings. Conversely, the **full max** requirement reflects the absolute maximum time a project could feasibly take if following Rule 21 as written. It assumes application deficiencies exist and that every step defined in the tariff to resolve deficiencies occurs, all optional extensions are utilized, and results meetings are chosen after every review or study.

The following tables detail the calculation of the partial max and full max requirements shown in Table 16 in Section 2.3.2.3. In each table, a "-" indicates that a step is assumed not to occur while an "X" indicates that a step is assumed to occur but that Rule 21 does not specify a required time limit for that step.

E.1 IR Only Track

Table E-1 outlines the calculation for the IR-only track. The partial max requirement is 105 BD assuming no application deficiencies and no IR results meeting. The full max requirement is 180 BD without these assumptions.

Table E-1. Calculation of Total Time Requirements for IR Only Track

Beginning of Step	End of Step	Tariff Requirement	Partial Max Steps	Full Max Steps
Application Validation				
Application submittal	Application deemed complete	10 BD	10 BD	-
Application submittal	First notification of deficiencies	10 BD	-	10 BD
First notification of deficiencies	Customer response to first notification	10 BD + 20 BD opt. extension	-	30 BD
Customer response to first notification	Second notification of deficiencies	10 BD	-	10 BD
Second notification of deficiencies	Customer response to second notification / application deemed complete	10 BD	-	10 BD
Fast Track: Initial Review				
Application deemed complete	IR completed and results to customer	15 BD	15 BD	15 BD

Beginning of Step	End of Step	Tariff Requirement	Partial Max Steps	Full Max Steps
IR completed and results to customer	Customer chooses IR results meeting	10 BD + 10 BD opt. extension	-	20 BD
Customer chooses IR results meeting	IOU offers to convene IR results meeting	5 BD	-	5 BD
IOU offers to convene IR results meeting	IR results meeting occurs / all issues resolved	Undefined	-	X
GIA Execution				
End of fast track / all issues resolved	IOU provides draft GIA	15 BD	15 BD	15 BD
IOU provides draft GIA	Customer signs and returns GIA	90 CD	90 CD	90 CD
Totals				
Total (sum of individual steps)			40 BD + 90 CD	115 BD + 90 CD
Total (BD)*			**105 BD**	**180 BD**

* Uses the average conversion of 90 CD equals 65 BD.

E.2 IR and SR Track

Table E-2 outlines the calculation for the IR and SR track. The partial max requirement is 135 BD assuming no application deficiencies and no IR or SR results meetings. The full max requirement is 240 BD without these assumptions.

Table E-2. Calculation of Total Time Requirements for IR and SR Track

Beginning of Step	End of Step	Tariff Requirement	Partial Max Steps	Full Max Steps
Application Validation				
Application submittal	Application deemed complete	10 BD	10 BD	-
Application submittal	First notification of deficiencies	10 BD	-	10 BD
First notification of deficiencies	Customer response to first notification	10 BD + 20 BD opt. extension	-	30 BD
Customer response to first notification	Second notification of deficiencies	10 BD	-	10 BD
Second notification of deficiencies	Customer response to second notification / application deemed complete	10 BD	-	10 BD
Fast Track: Initial Review				
Application deemed complete	IR completed and results to customer	15 BD	15 BD	15 BD

Beginning of Step	End of Step	Tariff Requirement	Partial Max Steps	Full Max Steps
IR completed and results to customer	Customer chooses to move to SR	10 BD	10 BD	-
IR completed and results to customer	Customer chooses IR results meeting	10 BD + 10 BD opt. extension	-	20 BD
Customer chooses IR results meeting	IOU offers to convene IR results meeting	5 BD	-	5 BD
IOU offers to convene IR results meeting	IR results meeting occurs	Undefined	-	X
IR results meeting occurs	Customer chooses to move to SR	10 BD + 10 BD opt. extension	-	20 BD
Fast Track: Supplemental Review				
Customer chooses to move to SR (and pays fee, if required)	SR completed and results to customer	20 BD	20 BD	20 BD
SR completed and results to customer	Customer chooses SR results meeting	15 BD	-	15 BD
Customer chooses SR results meeting	IOU offers to convene SR results meeting	5 BD	-	5 BD
IOU offers to convene SR results meeting	SR results meeting occurs / all issues resolved	Undefined	-	X
GIA Execution				
End of fast track / all issues resolved	IOU provides draft GIA	15 BD	15 BD	15 BD
IOU provides draft GIA	Customer signs and returns GIA	90 CD	90 CD	90 CD
Totals				
Total (sum of individual steps)			70 BD + 90 CD	175 BD + 90 CD
Total (BD)*			**135 BD**	**240 BD**

* Uses the average conversion of 90 CD equals 65 BD.

E.3 SIS Only Track

Table E-3 outlines the calculations for the SIS only track. Both the partial max and full max requirements assume that no material modifications are requested. The partial max requirement is 252 BD assuming no application deficiencies and no SIS results meeting. The full max requirement is 317 BD without the application deficiency and SIS results meeting assumptions.

Table E-3. Calculation of Total Time Requirements for SIS Only Track

Beginning of Step	End of Step	Tariff Requirement	Partial Max Steps	Full Max Steps
Application Validation				

Beginning of Step	End of Step	Tariff Requirement	Partial Max Steps	Full Max Steps
Application submittal	Application deemed complete	10 BD	10 BD	-
Application submittal	First notification of deficiencies	10 BD	-	10 BD
First notification of deficiencies	Customer response to first notification	10 BD + 20 BD opt. extension	-	30 BD
Customer response to first notification	Second notification of deficiencies	10 BD	-	10 BD
Second notification of deficiencies	Customer response to second notification / application deemed complete	10 BD	-	10 BD
Detailed Study (DS) Screens/Electrical Independence Tests				
Customer chooses DS (and pays fee, if required)	DS screens completed and results to customer	20 BD	20 BD	20 BD
DS screens completed and results to customer	IOU contacts customer to schedule scoping meeting	5 BD	5 BD	5 BD
IOU contacts customer to schedule scoping meeting	Scoping meeting occurs	Undefined	X	X
Scoping meeting occurs	IOU provides DS agreement	15 BD	15 BD	15 BD
IOU provides DS agreement	Customer executes DS agreement	30 BD	30 BD	30 BD
Independent Study Process: System Impact Study				
Customer executes DS agreement	IOU completes SIS and issues SIS report	60 BD	60 BD	60 BD
IOU completes SIS and issues SIS report	Customer requests SIS results meeting	10 BD	-	10 BD
Customer requests SIS results meeting	IOU offers to convene SIS results meeting	5 BD	-	5 BD
IOU offers to convene SIS results meeting	SIS results meeting occurs	Undefined	-	X
IOU complete SIS and issues SIS report / SIS results meeting occurs	Mutual agreement to waive facilities study	25 BD	25 BD	25 BD
GIA Execution				
End of ISP / all issues resolved	IOU provides draft GIA	30 CD	30 CD	30 CD
IOU provides draft GIA	Customer signs and returns GIA	90 CD	90 CD	90 CD
Totals				
Total (sum of individual steps)			165 BD + 120 CD	230 BD + 120 CD

Beginning of Step	End of Step	Tariff Requirement	Partial Max Steps	Full Max Steps
Total (BD)*			**252 BD**	**317 BD**

* Uses the average conversion of 120 CD equals 87 BD.

E.4 IR, SR, and SIS Track

Table E-4 outlines the calculations for the IR, SR, and SIS track. Both the partial max and full max requirements assume that no material modifications are requested. The partial max requirement is 312 BD assuming no application deficiencies and no IR, SR, or SIS results meetings. The full max requirement is 457 BD without the application deficiency and results meeting assumptions.

Table E-4. Calculation of Total Time Requirements for IR, SR, and SIS Track

Beginning of Step	End of Step	Tariff Requirement	Partial Max Steps	Full Max Steps
Application Validation				
Application submittal	Application deemed complete	10 BD	10 BD	-
Application submittal	First notification of deficiencies	10 BD	-	10 BD
First notification of deficiencies	Customer response to first notification	10 BD + 20 BD opt. extension	-	30 BD
Customer response to first notification	Second notification of deficiencies	10 BD	-	10 BD
Second notification of deficiencies	Customer response to second notification / application deemed complete	10 BD	-	10 BD
Fast Track: Initial Review				
Application deemed complete	IR completed and results to customer	15 BD	15 BD	15 BD
IR completed and results to customer	Customer chooses to move to SR	10 BD	10 BD	-
IR completed and results to customer	Customer chooses IR results meeting	10 BD + 10 BD opt. extension	-	20 BD
Customer chooses IR results meeting	IOU offers to convene IR results meeting	5 BD	-	5 BD
IOU offers to convene IR results meeting	IR results meeting occurs	Undefined	-	X
IR results meeting occurs	Customer chooses to move to SR	10 BD + 10 BD Opt. Extension	-	20 BD

Beginning of Step	End of Step	Tariff Requirement	Partial Max Steps	Full Max Steps
Fast Track: Supplemental Review				
Customer chooses to move to SR (and pays fee, if required)	SR completed and results to customer	20 BD	20 BD	20 BD
SR completed and results to Customer	Customer chooses to move on to detailed study	15 BD	15 BD	-
SR completed and results to Customer	Customer chooses SR results meeting	15 BD	-	15 BD
Customer chooses SR results meeting	IOU offers to convene SR results meeting	5 BD	-	5 BD
IOU offers to convene SR results meeting	SR results meeting occurs	Undefined	-	X
SR results meeting occurs	Customer chooses to move on to detailed study	20 BD + 20 BD Opt. Extension	-	40 BD
Detailed Study (DS) Screens/Electrical Independence Tests				
Customer chooses DS (and pays fee, if required)	DS screens completed and results to customer	20 BD	20 BD	20 BD
DS screens completed and results to customer	IOU contacts customer to schedule scoping meeting	5 BD	5 BD	5 BD
IOU contacts customer to schedule scoping meeting	Scoping meeting occurs	Undefined	X	X
Scoping meeting occurs	IOU provides DS agreement	15 BD	15 BD	15 BD
IOU provides DS agreement	Customer executes DS agreement	30 BD	30 BD	30 BD
Independent Study Process: System Impact Study				
Customer executes DS agreement	IOU completes SIS and issues SIS report	60 BD	60 BD	60 BD
IOU completes SIS and issues SIS Report	Customer requests SIS results meeting	10 BD	-	10 BD
Customer requests SIS results meeting	IOU offers to convene SIS results meeting	5 BD	-	5 BD
IOU offers to convene SIS results meeting	SIS results meeting occurs	Undefined	-	X
IOU complete SIS and issues SIS report / SIS results meeting occurs	Mutual agreement to waive facilities study	25 BD	25 BD	25 BD
GIA Execution				
End of ISP / all issues resolved	IOU provides draft GIA	30 CD	30 CD	30 CD
IOU provides draft GIA	Customer signs and returns GIA	90 CD	90 CD	90 CD

Beginning of Step	End of Step	Tariff Requirement	Partial Max Steps	Full Max Steps
Totals				
Total (sum of individual steps)			225 BD + 120 CD	370 BD + 120 CD
Total (BD)*			**312 BD**	**457 BD**

* Uses the average conversion of 120 CD equals 87 BD.

E.5 IR and SIS Track

Table E-5 outlines the calculations for the IR and SIS track. Both the partial max and full max requirements assume that no material modifications are requested. The partial max requirement is 277 BD assuming no application deficiencies and no IR or SIS results meetings. The full max requirement is 377 BD without the application deficiency and results meeting assumptions.

Table E-5. Calculation of Total Time Requirements for IR and SIS Track

Beginning of Step	End of Step	Tariff Requirement	Partial Max Steps	Full Max Steps
Application Validation				
Application submittal	Application deemed complete	10 BD	10 BD	-
Application submittal	First notification of deficiencies	10 BD	-	10 BD
First notification of deficiencies	Customer response to first notification	10 BD + 20 BD opt. extension	-	30 BD
Customer response to first notification	Second notification of deficiencies	10 BD	-	10 BD
Second notification of deficiencies	Customer response to second notification / application deemed complete	10 BD	-	10 BD
Fast Track: Initial Review				
Application deemed complete	IR completed and results to customer	15 BD	15 BD	15 BD
IR completed and results to customer	Customer chooses to move to detailed study	10 BD	10 BD	-
IR completed and results to customer	Customer chooses IR results meeting	10 BD + 10 BD opt. extension	-	20 BD
Customer chooses IR results meeting	IOU offers to convene IR results meeting	5 BD	-	5 BD
IOU offers to convene IR results meeting	IR results meeting occurs	Undefined	-	X
IR results meeting occurs	Customer chooses to move to detailed study	10 BD + 10 BD opt. extension	-	20 BD

Beginning of Step	End of Step	Tariff Requirement	Partial Max Steps	Full Max Steps
Detailed Study (DS) Screens/Electrical Independence Tests				
Customer chooses DS (and pays fee, if required)	DS screens completed and results to customer	20 BD	20 BD	20 BD
DS screens completed and results to customer	IOU contacts customer to schedule scoping meeting	5 BD	5 BD	5 BD
IOU contacts customer to schedule scoping meeting	Scoping meeting occurs	Undefined	X	X
Scoping meeting occurs	IOU provides DS agreement	15 BD	15 BD	15 BD
IOU provides DS agreement	Customer executes DS agreement	30 BD	30 BD	30 BD
Independent Study Process: System Impact Study				
Customer executes DS agreement	IOU completes SIS and issues SIS report	60 BD	60 BD	60 BD
IOU completes SIS and issues SIS report	Customer requests SIS results meeting	10 BD	-	10 BD
Customer requests SIS results meeting	IOU offers to convene SIS results meeting	5 BD	-	5 BD
IOU offers to convene SIS results meeting	SIS results meeting occurs	Undefined	-	X
IOU complete SIS and issues SIS Report / SIS results meeting occurs	Mutual agreement to waive facilities study	25 BD	25 BD	25 BD
GIA Execution				
End of ISP / all issues resolved	IOU provides draft GIA	30 CD	30 CD	30 CD
IOU provides draft GIA	Customer signs and returns GIA	90 CD	90 CD	90 CD
Totals				
Total (sum of individual steps)			190 BD + 120 CD	290 BD + 120 CD
Total (BD)*			**277 BD**	**377 BD**

* Uses the average conversion of 120 CD equals 87 BD.

E.6 IR, SR, SIS, and FS Track

Table E-6 outlines the calculations for the IR, SR, SIS, and FS track. Both the partial max and full max requirements assume that no material modifications are requested. The partial max requirement is 375 BD assuming no application deficiencies and no IR, SR, or SIS results meetings. The full max requirement is 510 BD without the application deficiency and results meeting assumptions.

Table E-6. Calculation of Total Time Requirements for IR, SR, SIS, and FS Track

Beginning of Step	End of Step	Tariff Requirement	Partial Max Steps	Full Max Steps
Application Validation				
Application submittal	Application deemed complete	10 BD	10 BD	-
Application submittal	First notification of deficiencies	10 BD	-	10 BD
First notification of deficiencies	Customer response to first notification	10 BD + 20 BD opt. extension	-	30 BD
Customer response to first notification	Second notification of deficiencies	10 BD	-	10 BD
Second notification of deficiencies	Customer response to second notification / application deemed complete	10 BD	-	10 BD
Fast Track: Initial Review				
Application deemed complete	IR completed and results to customer	15 BD	15 BD	15 BD
IR completed and results to customer	Customer chooses to move to SR	10 BD	10 BD	-
IR completed and results to customer	Customer chooses IR results meeting	10 BD + 10 BD opt. extension	-	20 BD
Customer chooses IR results meeting	IOU offers to convene IR results meeting	5 BD	-	5 BD
IOU offers to convene IR results meeting	IR results meeting occurs	Undefined	-	X
IR results meeting occurs	Customer chooses to move to SR	10 BD + 10 BD opt. extension	-	20 BD
Fast Track: Supplemental Review				
Customer chooses to move to SR (and pays fee, if required)	SR completed and results to customer	20 BD	20 BD	20 BD
SR completed and results to customer	Customer chooses to move on to detailed study	15 BD	15 BD	-
SR completed and results to customer	Customer chooses SR results meeting	15 BD	-	15 BD
Customer chooses SR results meeting	IOU offers to convene SR results meeting	5 BD	-	5 BD
IOU offers to convene SR results meeting	SR results meeting occurs	Undefined	-	X
SR results meeting occurs	Customer chooses to move on to detailed study	20 BD + 20 BD opt. extension	-	40 BD

Beginning of Step	End of Step	Tariff Requirement	Partial Max Steps	Full Max Steps
Detailed Study (DS) Screens/Electrical Independence Tests				
Customer chooses DS (and pays fee, if required)	DS screens completed and results to customer	20 BD	20 BD	20 BD
DS screens completed and results to customer	IOU contacts customer to schedule scoping meeting	5 BD	5 BD	5 BD
IOU contacts customer to schedule scoping meeting	Scoping meeting occurs	Undefined	X	X
Scoping meeting occurs	IOU provides DS agreement	15 BD	15 BD	15 BD
IOU provides DS agreement	Customer executes DS agreement	30 BD	30 BD	30 BD
Independent Study Process: System Impact Study (SIS)				
Customer executes DS agreement	IOU completes SIS and issues SIS report	60 BD	60 BD	60 BD
IOU completes SIS and issues SIS report	Customer makes initial posting of financial security	60 CD	60 CD	60 CD
Independent Study Process: Facilities Study (FS)*				
Customer makes initial posting of financial security	IOU completes FS and issues report (no upgrades required)	45 BD (60 if Upgrades Required)	45 BD	45 BD
IOU completes FS and issues report	Customer chooses FS results meeting	Undefined	-	X
Customer chooses FS results meeting	IOU offers to convene FS results meeting	5 BD	-	5 BD
IOU offers to convene FS results meeting	FS results meeting occurs	Undefined	-	X
GIA Execution				
FS report issued / FS results meeting occurs	IOU provides draft GIA	30 CD	30 CD	30 CD
IOU provides draft GIA	Customer signs and returns GIA	90 CD	90 CD	90 CD
Totals				
Total (sum of individual steps)			245 BD + 180 CD	380 BD + 180 CD
Total (BD)†			**375 BD**	**510 BD**

* Uses the average conversion of 180 CD equals 130 BD.

† The research team calculated the allowed time to complete FS after SIS using the posting of financial security as an intermediate step as this was simpler than summing the steps related to a SIS results meeting and modifications.

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