ATTACHMENT 1

Attachment 1

Questions to Parties

In responding to the questions below, parties are encouraged to consider and comment on the information submitted by Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E) and Southern California Edison Company (SCE) (jointly, Utilities) in response to the March 9, 2023, Administrative Law Judge Ruling (March Ruling).

Utility Distribution Planning Process (DPP) Improvements

Local Planning Engagement

1. Considering the Utilities' existing Local Planning Engagement practices, as filed in response to the March Ruling, what improvements should be made to the Utilities' DPP in terms of engagement and communication with tribal, local and regional planning entities?
2. Energy Division's 2022 Distribution Planning Community Engagement Needs Assessment Study Draft Scope of Work,[1] proposed that a consultant conduct outreach to help inform this proceeding. In other proceedings, such as the Microgrids and the Climate Adaptation proceedings, and in the PG&E Regionalization plan, the Commission has required Utilities to conduct outreach and community engagement. Should this proceeding also direct Utilities to assume this role? Would outreach by Utilities enable building and maintaining of partnerships with tribal, local, and regional planning entities and ensure community engagement is incorporated into the Utilities' DPP?
3. How should the Utilities' local planning engagement efforts on DPP be combined or coordinated with the community engagement efforts in other proceedings?

[1] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/distributed-energy-resources-action-plan/needs-assessment-sow-and-outreach-meeting-summary.pdf.

Demand Scenarios and Planning Horizon

4. Should different demand scenarios, based on the California Energy Commission's Integrated Energy Policy Report (IEPR) load forecast data and/or other datasets, be used for utility DPP?
   If yes,
   a. What datasets, and how many scenarios should be used?
   b. How should regional or local demand be considered in the Utilities' DPP in addition to the IEPR forecast?
5. How would using different demand scenarios in DPP impact other planning proceedings such as General Rate Case and Integrated Resource Planning proceedings?
6. Is a five-year planning horizon sufficient for distribution grid planning?
   a. If not, what is an appropriate planning horizon and why? Should the same planning horizon used for the IEPR demand forecast (min. 15 years)[2] be used for DPP?
   b. How should Utilities present and manage the risks of underbuilding and/or overbuilding under extended planning horizons?
   c. How should the planned investments identified under a longer planning horizon be prioritized for investment?

Transmission and Load Flexibility

7. How should the scope and cost of transmission and sub-transmission upgrades be considered in utility DPP?
8. Should the Grid Needs Assessment / Distribution Deferral Opportunity Reports (GNA/DDOR) filings account for secondary distribution infrastructure (e.g., service transformers) or additional primary distribution (e.g., feeder line segments) infrastructure needs? If so, how, and why? Would this result in avoided and/or deferred costs? If so, how?
9. How should load flexibility (dynamic rates and other flexible load management strategies) be addressed in utility DPPs and on what implementation timeline? Responses should consider the scope

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[2] The California Energy Commission forecasts "at least 15 years into the future to ensure adequate lead time for the Independent System Operator to analyze and approve transmission development, and for the permitting and construction of the approved facilities, to meet the projections." (*See* Public Utilities Code Section 454.57(e)(1).)

and status of the proceeding on Advance Demand Flexibility Through Electric Rates (Rulemaking (R.) 22-07-005).

Data Portals and Integration Capacity Analysis (ICA) Improvements[3]

The process to access the Utilities' data portals varies. SCE does not require registration. PG&E requires registration, and access is granted immediately. SDG&E requires registration, and access is not granted automatically or immediately and has an expiration date after which new access is required.

10. How do registration requirements impact the accessibility of the data portals and what changes are needed to improve access?

Generation and Load ICA Data Utility and Calculations

11. Should the Commission evaluate the accuracy of the Generation ICA and Load ICA data?
    c. Who should evaluate the accuracy of the Generation ICA and Load ICA data?
    d. What metrics should be used for assessing the ICA data accuracy?
    e. How frequently should the accuracy of the ICA data be evaluated?
    f. What is an appropriate timeline for implementing the accuracy improvements?
12. How do segments with ICA hosting capacity equal or close to 0 kilowatts (kW) affect project planning for DER Capacity Analysis data and project developers?
13. Are there other alternatives to hosting capacity maps that can facilitate cost effective siting of DERs on the electric grid?

Generation ICA

14. For which types of projects is Generation ICA most useful? Be specific as to the size of the project (nameplate capacity less or greater than, X kW,), type of project (solar, storage, other), its service tariff (Net Energy Metering, Net

[3] Utilities provide electric distribution system mapping data on their websites. This data is located in the Utilities' data portals which provide information on distribution capacity for distributed energy resources (distributed energy resources) siting. A component of the data portals is ICA maps, which includes Load ICA and Generation ICA. Load ICA refers to the available grid capacity for interconnecting new load. Generation ICA refers to the available grid capacity for interconnecting new generation.

Billing Tariff, other) and how useful (very useful, somewhat useful, or not useful) the ICA data is for each project type.

15. What are the most critical Generation ICA improvements needed to facilitate siting of DERs and streamline DER interconnection? How should these improvements be made?

Load ICA

16. For which types of projects is Load ICA most useful? Be specific as to the size of the project (nameplate capacity less or greater than, X kW,), type of project (solar, storage, other), its service tariff (Net Energy Metering, Net Billing Tariff, other) and how useful (very useful, somewhat useful, or not useful) the ICA data is for the project.

17. Utilities filed plans to improve their Load ICA maps in February of 2022.

    a. How do the Utilities' proposed Load ICA improvements align with and support the goals of Electric Vehicle (EV) load siting and building electrification? What further improvements are needed to advance accuracy and usefulness?

    b. Given the Utilities' stated implementation timeline of 2025/2026, what near-term steps can Utilities take to improve the Load ICA?

18. Should load flexibility be incorporated in Load ICA results and maps? If so, then how?

DPP Alignment with Transportation Electrification

19. How can Utilities be proactive in planning distribution upgrades for EV adoption and associated EVSE installations? Who should Utilities collaborate with to identify EV locations and forecasted loads?

20. How should Utilities plan for broader transportation electrification including Medium-Duty and Heavy-Duty EVs, fleet, freight, and ports?

    a. How will Utilities meet the short-term needs of the added demand from Medium-Duty and Heavy-Duty EV fleet and depots?

    b. How can Utilities employ targeted DERs and load management strategies to meet the added load from Medium-Duty and Heavy- Duty EV fleet and depots?

21. How should Utilities ensure they have sufficient grid capacity and DER visibility to efficiently implement the secondary distribution infrastructure, non-wires alternatives, and load management strategies

required to support the Transportation Electrification investments envisioned through 2030?[4]

DIDF Reform

In responses to the following DIDF Reform questions, parties should identify which improvement should be implemented for the 2023/2024 DIDF Cycle and what items are appropriate for the 2024/2025 DIDF Cycle.

"Known Loads"

22. Which of the following items should be included and tracked year over year via the Utilities' annual GNA/DDOR filings?[5]
    a. Comparison of Utilities' known loads to the IEPR demand forecast.
    b. Known loads by customer type (commercial, residential, industrial) and customer load category (Building Load, Agricultural Pumps, Cultivation, EV load, etc.)
    c. Standardized reporting format across Utilities[6]
    d. Any other recommended improvements identified in the IPE 2023 Post-DPAG Report.
23. Considering the misalignment between the IEPR demand forecast and "known load" projects as identified in the Independent Professional Engineer (IPE) DPAG and Post-DPAG reports and the Kevala DIDF report:[7] How should Utilities investigate and manage the risks of underbuilding and/or overbuilding caused by this misalignment? Does this increase the risk of missing DER deferral opportunities? If so, how should it be resolved?

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[4] D.22-11-040 identifies approximately $18.5 billion allocated to Transportation Electrification Investments by 2030.

[5] This would be in addition to the existing requirements on known loads data directed by the June 16, 2022, DIDF Reform Ruling (at 10-12). https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M486/K447/486447191.PDF

[6] For example, PG&E and SDG&E provide annual values while SCE provides five-year and 10-year totals, PG&E does not currently provide actual load amount and actual in-service dates, SDG&E currently reports the "date customer made the request" instead of "initial in-service date initially requested by the customer", PG&E adjusts its future loads to align with the IEPR demand forecast by Year 10 as opposed to Year Five. SDG&E makes the adjustment by Year Five. SCE does not adjust to the IEPR demand forecast. (See attachment 2 for the 2022 IPE Post DPAG Report.)

[7] See attachment 2 for the 2022 IPE Post DPAG Report (at 26-34), IPE SDG&E 2022 DPAG Report (at 16-18), IPE PG&E 2022 DPAG Report (at 10-12), IPE SCE 2022 DPAG Report (at 11-19), and Kevala 2022 Distribution Investment Deferral Framework: Evaluation and Recommendations report (at 11-17).

Potential Pause of the Focus on Reviewing Deferral Opportunity Selection

24. Given the proceeding schedule and scope of issues for Track 1, Phase 1, what changes could be made to the DIDF process, starting in 2023, to free up stakeholder time for broader DPP reform discussions? For example, should the focus on deferral opportunity identification, selection, and review via the DPAG (roughly August 15th to November 15th) be paused during the 2024 and 2025 DIDF cycles to allow time for alternate stakeholder workshops?

Resiliency Grid Service

25. Should the definition of resiliency microgrid services be clarified via the DIDF Reform process to include other resiliency services?[8]

Partnership Pilot and RFO

26. To date, no contracts have been signed for a Partnership Pilot procurement. However, for the 2021/2022 DIDF Cycle, PG&E awarded two deferral contracts via the RFO solicitation process for behind-the-meter projects.[9]
    a. What improvements can be made to the Partnership Pilot to increase the number of deferral contracts awarded?
    b. To what extent does bidder certainty challenge Partnership Pilot success, and how can bidder certainty be increased for the Pilot

(END OF ATTACHMENT 1)

[8] The definition currently reads, "Resiliency (microgrid) services are load-modifying or supply services capable of improving local distribution reliability and/or resiliency. This service provides a fast reconnection and availability of excess reserves to reduce demand when restoring customers during abnormal configurations" (D.16-12-036 at 8).

[9] PG&E Advice Letter 6755-E, Mormon Bank 2 and Saratoga 1106 project details in Appendix B1 at p. 20.

ATTACHMENT 2

2023 Independent Professional Engineer

Final IPE Post DPAG Report

Public Version

Submitted to Energy Division, PG&E, SCE, and SDG&E

Date: March 29, 2023

Resource Innovations

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Half Moon Bay, CA 94019

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Statement of Confidentiality

The CPUC made provision for the Investor-Owned Utilities to request confidentiality treatment for certain data submitted in their GNA/DDOR reports or other material provided to the IPE that is contained in this report. The utilities have indicated that no data in this report is confidential. Thus, this PUBLIC VERSION of the report can be distributed to any interested party.

Contents

1. Introduction and Background

Summary of CPUC April 13, 2020 and May 7, 2020 Rulemaking

The paragraphs that follow summarize the parts of the April 13, 2020 CPUC Ruling (14-08-013) that directly impact the role of the IPE and/or this report.

The Ruling modified the Distribution Investment Deferral Framework (DIDF) process and filings with respect to the Independent Professional Engineer (IPE) scope of work and provided the updated 2020-2021 DIDF cycle schedule. Attachments A and B of the Ruling include a listing of the IPE-specific reforms discussed in the Ruling and the updated IPE scope of work. These Attachments of the Ruling are attached as Appendix A of this report.

In Decision 18-02-004, the Commission adopted the DIDF. Building upon the Competitive Solicitation Framework developed in the companion Integrated of Distributed Energy Resources proceeding, the DIDF established an ongoing annual process to identify, review, and select opportunities for third party-owned distributed energy resources (DERs) to defer or avoid traditional capital investments by the investor-owned utilities (IOUs) on their electric distribution systems. Decision 18-02-004 ordered the IOUs to implement the DIDF as an annual planning cycle that would potentially result in the selection of distribution upgrades for deferral through the competitive solicitation of DERs.

The DIDF was implemented in 2018 and 2019 with the expectation that it would be evaluated and revised after each cycle to improve the process. To that end, the assigned Administrative Law Judge (ALJ) issued a Ruling Requesting Answers to Questions to Improve the Distribution Investment Deferral Framework Process on February 25, 2019 (February 25, 2019 Ruling). Based on comments received in response to the questions, the ALJ issued a Ruling Modifying the Distribution Investment Deferral Framework Process on May 7, 2019 (May 7, 2019 Ruling). Stakeholders proposed additional recommendations for DIDF reform throughout the 2019 DIDF cycle. A Ruling Requesting Comments on Possible Improvements to the 2020 Distribution Investment Deferral Framework Process was subsequently issued on November 8, 2019 (November 8, 2019 Ruling), and the contents of this Ruling further modify the DIDF. A Ruling on May 11, 2020 modified the DIDF filing and process requirements including proposing a number of possible reforms to the DIDF.

The CPUC issued Decision 21-02-006 on February 12, 2021 titled Decision Adopting Pilots to Test Two Frameworks for Procuring Distributed Energy Resources that Avoid or Defer Utility Capital Investments. In that ruling the CPUC added two additional procurement mechanisms to the DIDF cycle and spelled out how pilots of these two mechanisms are to be implemented over the next few DIDF cycles. The two new mechanisms are called the Standard Offer Contract (SOC) pilot, which applies to in front of the meter (IFOM) DERs, and the Partnership Pilot (PP), which applies to behind the meter (BTM) DERs. The ruling also includes some revisions to the DIDF process and timing which are followed in this cycle's IPE review and in this report.

This decision requires IOUs to recommend at least one Tier 1 and two Tier 2/3 projects for the Partnership Pilot, which is only open to behind-the-meter (BTM) DER technologies. In addition, IOUs are required to recommend at least one Tier 1 project for the SOC pilot, which is only open to in-front-of-the-meter (IFOM) DER technologies. The IPE scope of work outlined in Appendix A provides for improvement to the IPE review process based on comments received and clarifies that IPE's work for each IOU will be overseen and approved by Energy Division. According to the Ruling, it is important that the IPE has sufficient time to prepare the IPE Plans in advance of the GNA/DDOR filings and that after the filings, the IPE has the cooperation and coordination of the IOUs necessary to collect the data needed for review in time to prepare the IPE Preliminary Analysis of GNA/DDOR Data Adequacy and IPE DPAG Report.

The revised IPE scope reflected in Ruling 14-08-013 includes the requirement to develop an IPE Plan that will cover most if not all of the IPE activities.

The Ruling states that to further assist the IPE with DPAG Report completion, a new IPE Post DPAG Report deliverable is included within the IPE scope of work. The IPE Post DPAG Report should review and compare overall IOU DIDF compliance and make recommendations for process improvements and DIDF reform.

As stated in the May 7, 2019 Ruling, the IPE shall report directly to the Energy Division while preparing its deliverables and conducting its analyses for DIDF implementation. The April 13, 2020 Ruling states the term of the IPE scope of work shall be the entire DIDF cycle, which starts on January 1 each year to plan for Pre-DPAG and DPAG implementation and concludes on July 31 the following year after all RFOs are concluded and all DIDF reforms are implemented. As a result, IPE scopes of work for each DIDF cycle will overlap.

Independent Professional Engineer

The California Public Utilities Commission (Commission) rulings direct Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities or IOUs) to enter into a contract with an Independent Professional Engineer (IPE). The role of the IPE is as previously described.

Through a contract with Nexant, Inc. (now Resource Innovations), the three utilities separately engaged Mr. Barney Speckman[1], PE, to serve as their advisory engineer (referred to as the Independent Professional Engineer (IPE)) for the scope described in the April 13, 2020 CPUC Ruling.

[1] Consistent with the CPUC decision, the contract with Resource Innovations, the firm where Mr. Speckman is employed, provides for other individuals within the organization to assist Mr. Speckman to perform the work in the IPE contract provided that these other individuals are also bound by the same confidentiality and conflict of interest requirements that Mr. Speckman is required to meet.

1.1. IPE Plan

As required by the April 13, 2020 Ruling, the IPE developed an IPE Plan for each utility that served to guide the IPE's steps to implement its 2021/2022 DIDF cycle work scope. The plan was developed using a three-step process:

1. In step 1 the IPE developed a draft IPE Plan working with the Energy Division and each utility by mid-May 2022.

2. The Plan was distributed to the service list and also discussed at the CPUC Distribution Forecasting Working Group meeting - both in an attempt to obtain stakeholder feedback on the plan.

3. Based upon stakeholder feedback received and under the direction of the Energy Division, the IPE revised the plans.

The IPE Plan covers the business processes that the IOUs use to identify which distribution and/or subtransmission projects are recommended to proceed to an RFO (or the SOC or PP) seeking DER offers to determine if there is a cost-effective non-wires alternative. One of the core purposes of the plan is answer the question – Are the IOUs identifying every project that could feasibly and cost effectively be deferred by DERs?

The business processes in the Plan are organized generally in the order that they are performed. Starting with capturing the peak load values for each circuit for 2021, using the CEC IEPR forecasts to develop utility specific system level values which are then disaggregated to the circuit level adjusted for known loads and then used to determine if there is an overload or any other issue during the planning period. For circuits that have a need, a planned investment is selected, capital costs developed for that project, and the planned investments are screened to develop a list of candidate deferral projects. These candidate deferral projects are then prioritized into tiers using several metrics and then considered for solicitation through an RFO, or through the SOC pilot or Partnership pilot.

1.2. Definitions of Verification and Validation

As part of the development and implementation of the IPE Plan, detailed definitions were developed to clarify the meaning of Verification and Validation as applied to the IPE scope of work. These definitions which are used and applied in all IPE deliverables are listed below:

Verification – Is a review performed by the IPE during which an independent check is performed to determine if the results produced were developed using data assumptions and business processes that were defined and described by the utility or are based upon standard industry approaches that do not have to be defined and described. In other words, "Did the IOU follow their own processes correctly as defined by the IOU?"

Validation – Is a review performed by the IPE during which an independent assessment is performed of the appropriateness of the approach taken by the utility to perform a task from an engineering, economics and business perspective. In other words, “Are the processes implemented by the IOU the best way to identify all planned investments that could feasibly be deferred by DERs cost effectively? And to what extent were the IOU methodologies appropriate and effective?”

1.3. Approach to Data Collection

The information reflected in this report was obtained through a number of methods including:

- The GNA and DDOR Reports, and associated data reviewed were the confidential version of those documents that were filed by the utilities. Note that SCE filed an abbreviated DDOR on September 2, 2022 and a final GNA/DDOR on January 13, 2023.

- The remainder of the information used to complete this report was data provided in response to IPE requests for information in 2022 and 2023.

1.4. Report Contents

The remainder of this report includes the following sections:

- Section 2 – Load Forecasting - Known Load Projects
- Section 3 – Prioritization Methodology for Pilot Project Selection
- Section 4 – Known Load Tracking
- Section 5 – Load Forecast Uncertainty Metric in Project Prioritization
- Section 6 – Results of Load Forecasting Comparison
- Section 7 – Electric Vehicle Known Load Growth Projects
- Section 8 – Resiliency Needs in the GNA
- Appendix A – SCE Known Load Tracking Data
- Appendix B – PG&E Known Load Tracking Data
- Appendix C – SDG&E Known Load Tracking Data

2. Load Forecasting - Known Load Projects

In this section we review the use and impact of known load growth projects (or known load projects or simply, known loads) on the three utilities' distribution planning process. This review is based on the material regarding known loads gathered in the past three to four DIDF cycles and included in previously distributed IPE DPAG and the 2021 Post DPAG reports. The IPE had reviewed the methodologies used by the three IOUs regarding known loads in the 2021 Post DPAG report. The recommendations provided here builds on those provided in the prior cycle.

2.1. Background

The three IOUs use known load projects in conjunction with the CEC IEPR forecasts to forecast the load growth for the GNA planning period. The term Known Load Projects[2] is used in general by all three utilities to mean load growth due to new or additional load that is based upon customer requests for new or additional service. As such, known load projects are site specific and provide insight into the future loading of circuits on which load growth is likely to occur.

While all the three utilities use known load projects to reflect load increases in their circuit-level load forecasts, they use different approaches for incorporating these projects into their GNA load forecasts. The purpose of this section is to review the approaches used by the utilities for including known load projects in their load forecasts and to develop recommendations for possible improvement.

Definitions Used in This Report

- **Known Load Projects** – "Known load projects" or simply "known loads" are forecasts of load growth that are based upon the requests for new or additional service from residential, commercial and industrial customers received by the utility. This is a term that is used by all three utilities in their reports in one form or another.
- **Embedded Known Loads** – Embedded known loads are those known loads that are already accounted for in the CEC IEPR forecasts. This is a term that is currently used only by SCE – its use is explained in Section 2.2.
- **Incremental Known Loads** – Incremental known loads are those known loads that are included in load forecasts that are in addition to the load growth forecasted in the CEC IEPR forecast. This is a term that is currently only used by SCE – its use is also explained in Section 2.2.

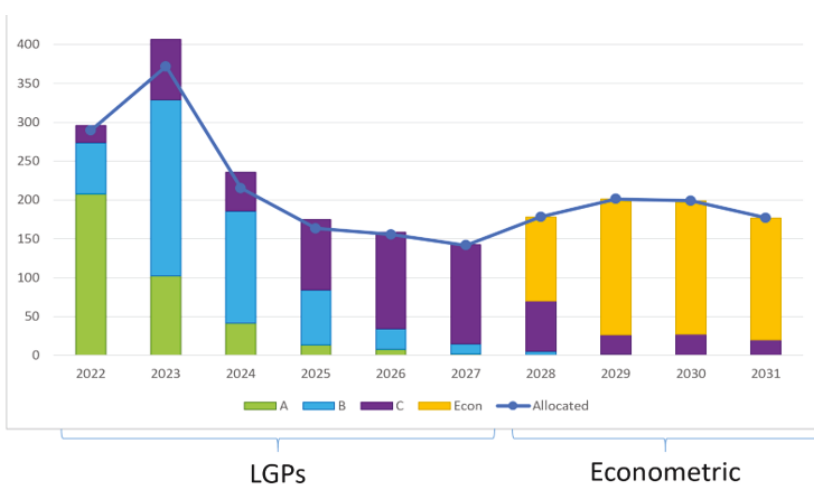
[2] Projects here refers to customer projects such as new commercial EV charging stations, new housing developments, new cultivation facilities, etc.

2.2. Treatment of Known Loads in the Grid Needs Assessment

Southern California Edison

SCE uses both embedded and incremental known load projects in their GNA. SCE developed a methodology which they call the "Whirlpool" method, to ensure that the sum of all embedded known loads in any given year of the forecast do not exceed the CEC growth forecast for that year. If the sum of the embedded known loads in any given year exceeds the CEC IEPR growth for that year, the methodology includes only those embedded known load projects that have the highest likelihood of being completed on time until the sum is equal to or less than the CEC annual growth forecast. SCE uses a Level of Certainty[3] (LOC) questionnaire score to determine which projects to include and which to shift to a later year. After all embedded loads are included in one of the ten planning years, any residual CEC IEPR load growth is disaggregated using econometric parameters. As a result, all embedded known loads are in included in the forecast over the planning period and therefore none are "lost" in the process. The Whirlpool method and the LOC questionnaire are described in detail in the 2022 IPE SCE DPAG Report. The net result of the application of the Whirlpool method in the 2022/2023 DIDF cycle is that individual embedded known loads made up all of the load growth for six years (2022-2027) in the CEC IEPR forecast as shown in Figure 2-1 (provided by SCE) where the blue line represents the CEC IEPR annual growth. The load growth projects referred to as A, B or C projects are projects with the highest certainty (Type A), next highest (Type B) and lowest (Type C). The remaining CEC IEPR annual load growth was disaggregated using an econometric methodology. We can see from the figure that econometric variables are used in years seven and beyond to allocate to the circuit level the remining load growth in the CEC IEPR forecasts. It should be pointed out that this figure does not include the incremental load growth projects, discussed next, that are added on top of the loads shown.

Figure 2-1: 2022 Embedded and Economic Load Growth (SCE-Provided Chart)



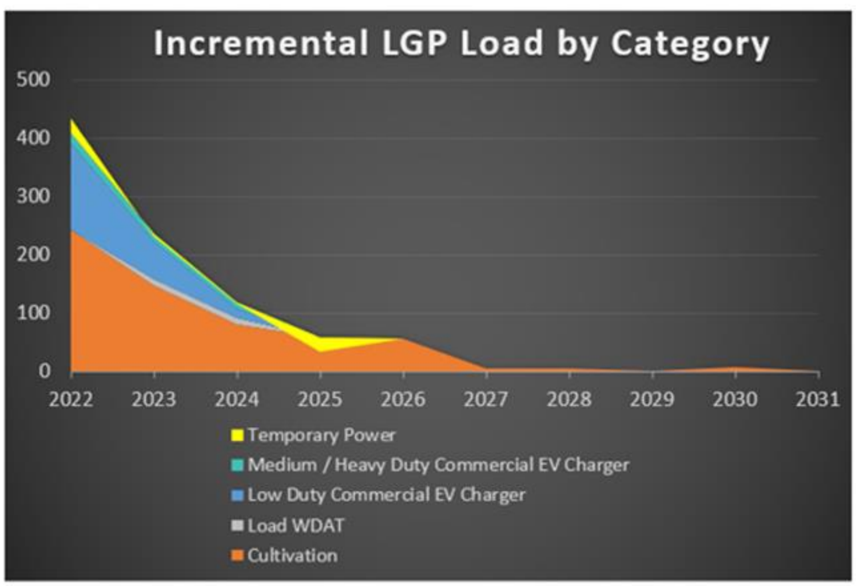
[3] The LOC score for each embedded known load project is developed by planning engineers based upon the state of development of the customers project for which it is requesting new or additional load. The LOC is a two-dimensional matrix that assess the state of progress of the project in aeras that include project application, construction, environmental permitting, status of additional SCE equipment and other factors.

SCE also includes incremental load growth projects in its forecasting process, These known loads are incremental to the loads forecasted in the CEC IEPR. In the 2022/2023 DIDF cycle, these incremental loads fell into five categories (listed roughly in largest to smallest order in load MW) – 1) Cultivation operations, 2) Low Duty, Medium Duty/Heavy Duty Commercial EV Chargers, 3) Load WDAT, 4) Temporary Power and 5) Customer Substations for Transmission Substation Planning, as shown in Figure 2-2. In other words, for known loads driven by customer requests that fall into these five categories, SCE includes these loads in addition to the embedded known loads previously discussed.

The categories of known loads that have been considered as incremental have changed over the last 4 years. For example, mega-tract homes and large data centers were considered as incremental in the 2018 DIDF (first application of incremental known loads) and commercial EV charges were not. SCE has been working with the CEC toward including all known loads in the CEC IEPR forecast which would eliminate the need for SCE to utilize incremental known loads in the GNA. The trend of incremental known loads over a four-year period is discussed in the next section.

We note that SCE's data for incremental known loads often reflects values before they are adjusted (discounted) for customer load diversity. The method of developing discount factors varies depending upon the customer type and the load data provided. The average discount factor value is about 0.8. We will note in this report, if values have already been discounted.

Figure 2-2: 2022 Incremental Load Growth Projects before Discounting for Diversity (SCE-provided chart)



The incremental known loads (before the application of discount factor) in the 2022/2023 DIDF for the first five years were 432 MW, 231 MW, 116 MW, 33 MW, and 55 MW respectively and are almost zero starting in 2027. Thus, for the first five years of the planning period, the load forecast used by SCE is higher than the CEC IEPR forecast by the amount of these annual incremental loads.

To make it easier to compare the SCE data with the data plotted for PG&E and SDG&E later in this section, Figure 2-3 and Figure 2-4 which show annual known loads and cumulative known loads for both embedded and incremental known loads are included[4].

Figure 2-3: SCE Annual Load Growth 2022 DIDF

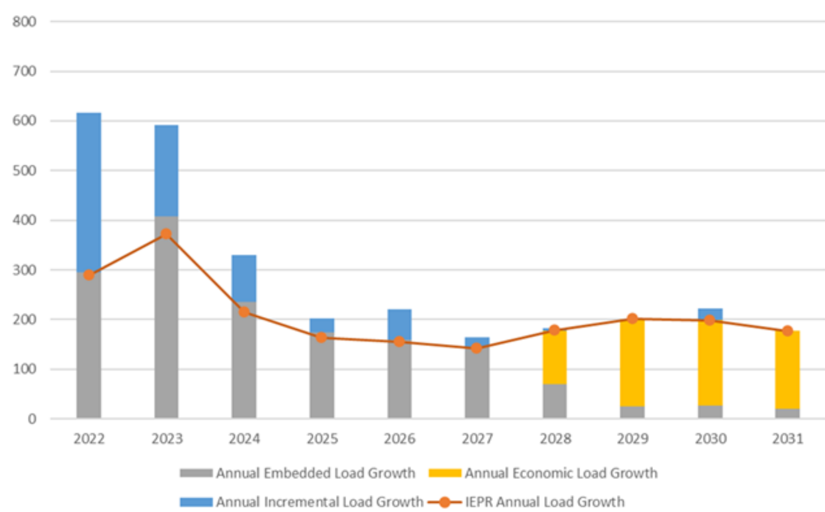
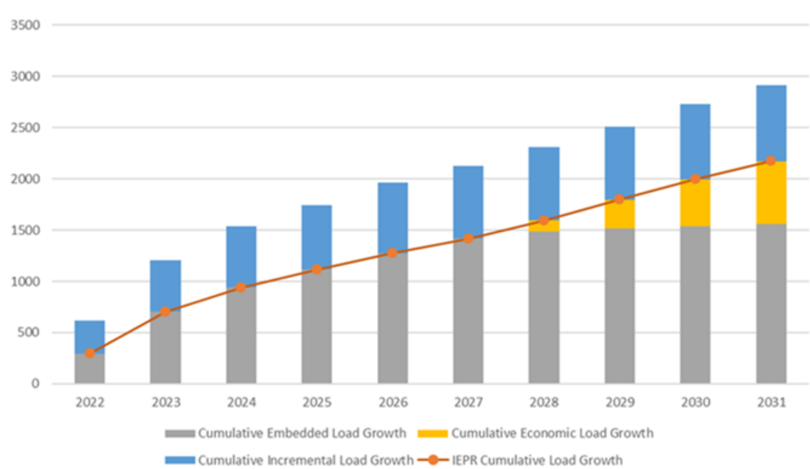


Figure 2-4: SCE Cumulative Load Growth 2022 DIDF



SCE Known Load Project Trend

The trend in known loads (embedded and incremental), as well as the EV commercial charger known loads (EV known loads), which are a component of the incremental known loads, was analyzed using

[4] These two plots were developed, in part, with data that was obtained from similar figure provided by SCE.

the SCE known load data from the past four DIDF cycles. The trends that were observed while studying the cumulative known loads (i.e., sum of the known loads for the 10-year forecast period), are discussed first. Figure 2-5 shows the cumulative EV known loads for the 10-year forecast period that were included in the last four DIDF cycles (2019 DIDF to 2022 DIDF). Figure 2-6 shows the number of circuits that had a known EV commercial charger load projects in each of the last four DIDFs. From these plots we see that the MW amounts associated with EV known loads and the number of circuits with these loads have been increasing steadily.

Figure 2-5: SCE EV Commercial Charger Known Loads for Past Four DIDF Cycles

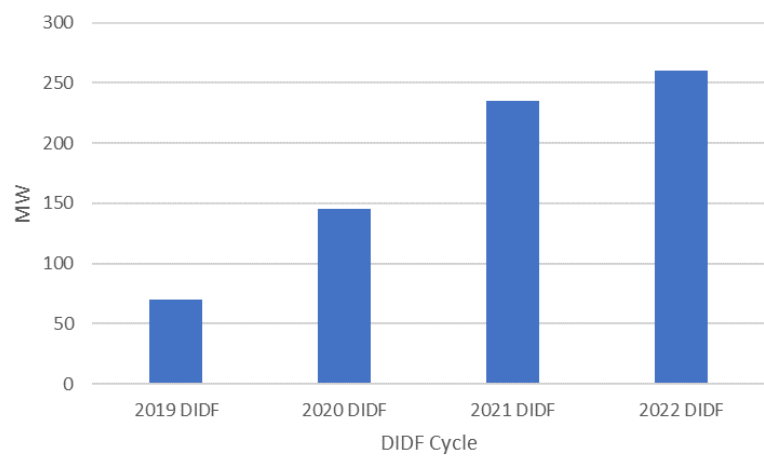
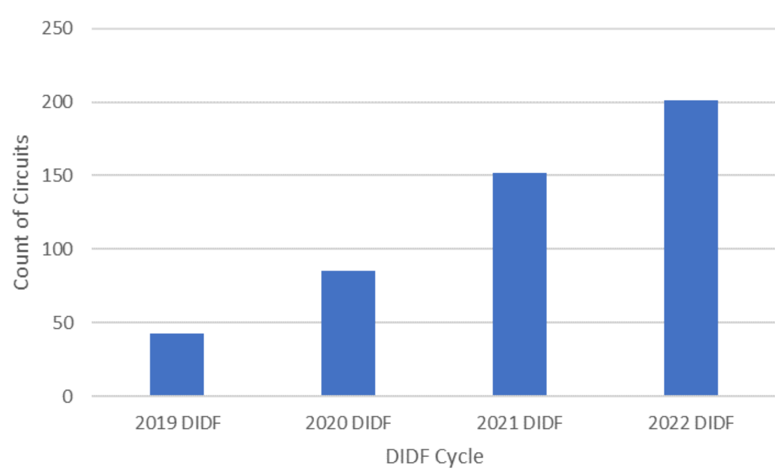


Figure 2-6: SCE EV Number of Circuits Impacted for Past Four DIDF Cycles



Based upon California's stated transportation electrification goals, it is expected that EV known loads will continue to grow in absolute terms for the foreseeable future. As such, capturing these loads properly in the GNA load forecasting process will be important to upgrading the grid to support meeting California's electrification goals.

Figure 2-7 shows the total known load MWs (embedded and incremental) for the 10-year forecast period from the last three DIDFs (data from the 2019 DIDF was not available). We see that the total known loads have grown in this period, partly due to the growth in EV known loads, however, we also see that the total incremental MWs have decreased during this period. We believe this is primarily due to the decrease in cultivation known loads over this period.

Figure 2-8 shows the embedded and incremental known loads as a percentage of the total known load for each of these DIDF cycles. The plot shows that incremental loads constitute a smaller portion of the total known loads in the 2022 cycle when compared to the 2021 and 2020 cycles. As mentioned before, we believe the reduction in the known load percentages is due primarily to the decrease in cultivation known loads over this period.

Figure 2-7: SCE Total Known Loads (embedded and incremental) for Past Three DIDF Cycles in MWs

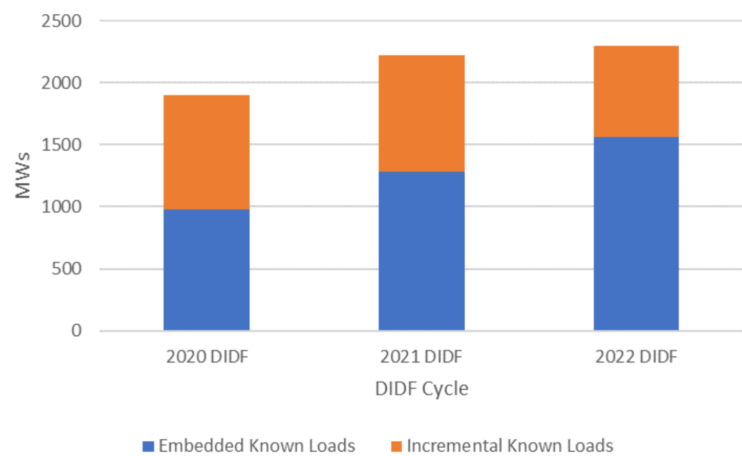


Figure 2-8: SCE Total Known Loads for Past Three DIDF Cycles as a percentage of embedded and incremental Loads

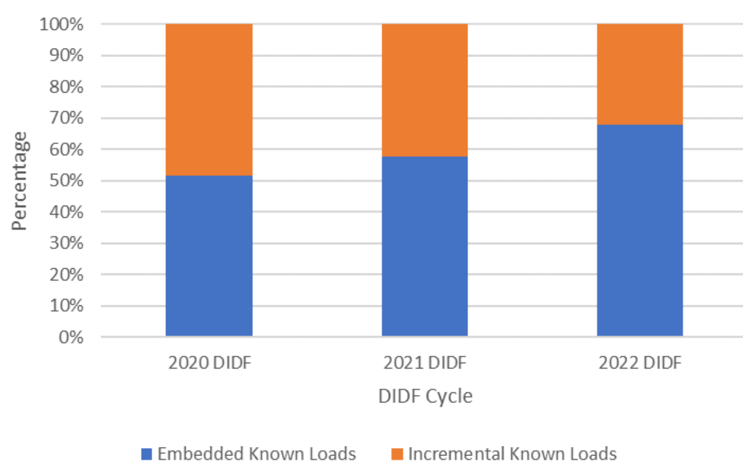
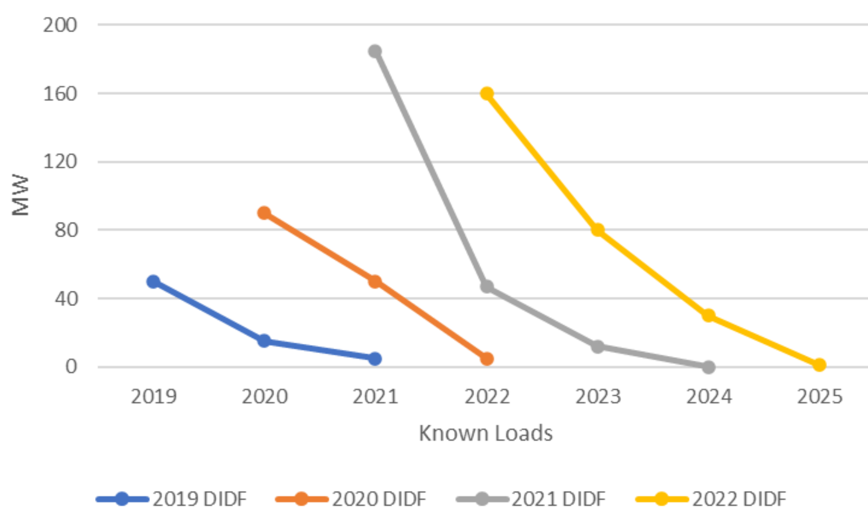


Figure 2-9 shows the annual known loads (Figures 2-5 and Figure 2-6 showed cumulative EV known loads for the forecast period) associated with commercial chargers that were included in SCE's past four DIDF cycles. We see that all four curves have a similar shape – with the largest amount in the first year of the cycle and the smallest in the third or fourth year of the cycle. These curves demonstrate that customer requests for EV loads diminish over time. Developers are more certain about their specific business needs looking out one year and less certain (and therefore make fewer requests for service) about their needs for the second year and even less certain for the third year and so on.

When one looks at known loads for EV commercial charging from the past four DIDF cycles, it can be observed how these loads for any given year change over time. For example, let us take a look at the year 2021. In the 2019 DIDF, EV known loads for 2021 were essentially zero (blue curve). In the next DIDF cycle, the EV known loads for 2021 increased to 50 MWs (orange curve) and in the following DIDF cycle (i.e., 2021 DIDF) the known loads for 2021 increased significantly to about 185MW (grey curve).

Figure 2-9: SCE Total EV Commercial Charger Known Loads for Past Four DIDF Cycles



These curves demonstrate that in any one cycle, EV known loads (driven by customer requests for service) have a limited time horizon. Based upon the SCE data above, it suggests that EV load customers (typically electric vehicle service providers and fleet operators) make requests for service roughly 2-3 years, at most, before they want service and often with much less notice. From the plots we see that this time horizon seems to be improving somewhat in that EV known loads in the 2022 DIDF extend out for four years (although still diminishing in each year) compared to three years in the 2019 DIDF cycle. In Section 7, of this report, we discuss efforts by the three utilities to increase their outreach to developers/stakeholders to improve their insight into where EV load service is likely to be requested in the future – something that should improve the inherent visibility of EV known loads used in future DIDF cycles.

Pacific Gas & Electric

PG&E also uses known load projects in their GNA. However, they do not separate their known load projects into embedded and incremental like SCE. PG&E considers all of their known loads as being included in the CEC IEPR when considering the entire 10-year planning period as explained below. PG&E's methodology used in the 2022 GNA to determine how many of the known load projects to place into individual years and to complete the 10-year forecasting process is as follows:

- PG&E included 90% of the known load amounts for the known loads in the first 3 years (2022-2024). This is to reflect the fact that the loads associated with new service requests for these early years are less likely to materialize than those in outer years. For the remaining years (i.e., 2025-2031), PG&E uses the known load project amounts for those years without any type of discounting or adjustments.
- PG&E does not make any further adjustments to the known load growths calculated as shown above, even if they happen to exceed the CEC IEPR forecast in any given year. This can be seen to occur in the years 2022 and 2023 in Figure 2-10.
- PG&E also includes economic load growth in their load growth forecasts. PG&E includes an equal amount of economic growth in each year starting from year 4 and up to the point that the total load growth over the 10-year planning period (known load and economic growth) is equal to the total load growth over the 10-year planning period in the IEPR as shown in Figure 2-10 and Figure 2-11. As a result, PG&E's total load growth over the planning period is the same as the IEPR total value, but its load growth forecasts in specific years can and do exceed the CEC annual values as seen in Figure 2-10. This is a result of PG&E ensuring that the total load growth it uses over the 10-year planning period is equal to the total load over that same period in the CEC IEPR. Thus, annual load growth above the CEC values in 2022-2023 must be offset by annual load growth below the CEC values for 2024-2031. Figure 2-11 compares the cumulative load growth in the IEPR and the load growth used by PG&E in the GNA.

In addition to new commercial and industrial loads, the known load projects in the first few years are driven by EV charging station loads and cannabis cultivation.

Figure 2-10: PG&E Annual known load growth, economic load growth and IEPR forecast

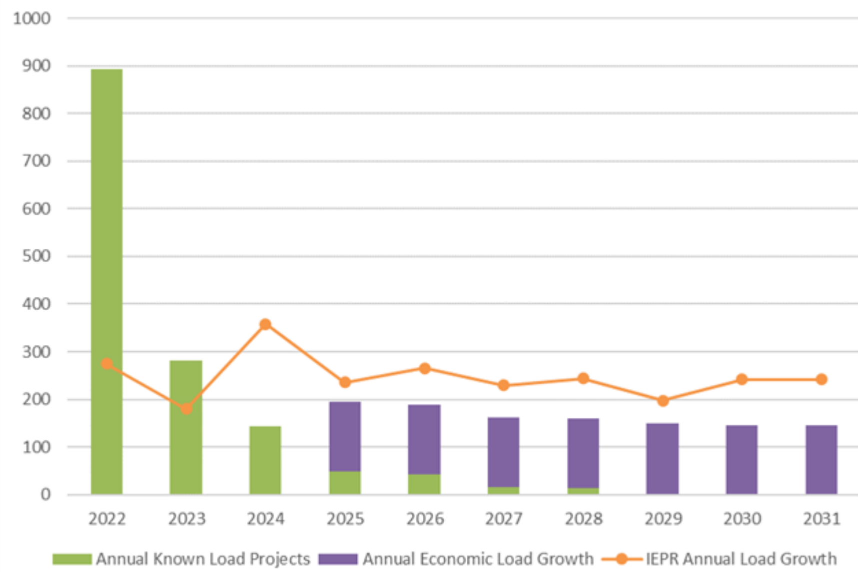
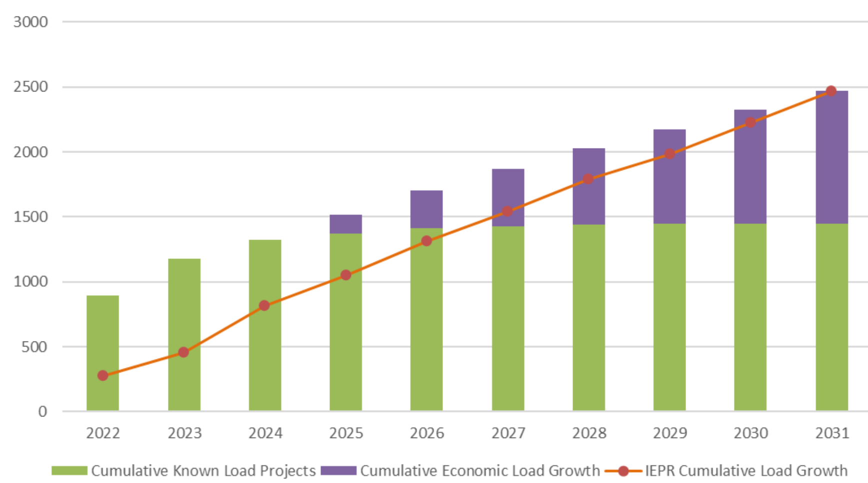


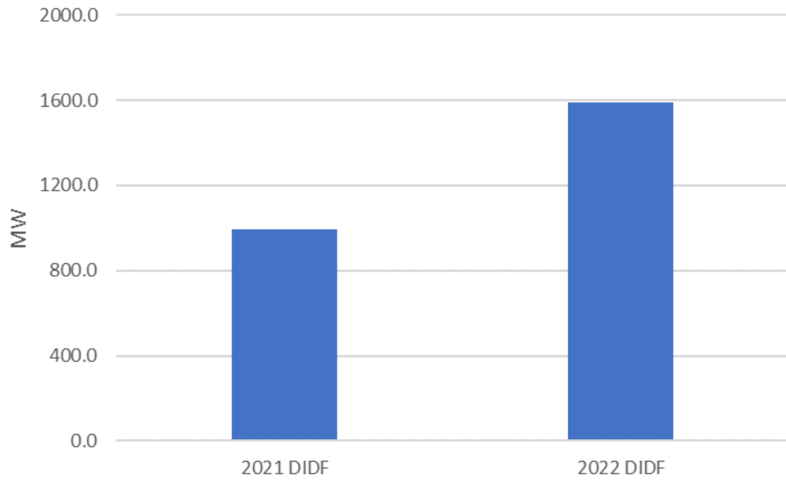
Figure 2-11: PG&E Cumulative known load growth, economic load growth and IEPR forecast



PG&E Known Load Project Trend

In this section we use available data to demonstrate the trend in PG&E's use of known loads in its DPP over the last two DIDF cycles since detailed known load data was gathered only for these two cycles Figure 2-12 shows the total known load MWs for the 10-year forecast period from the last two DIDFs (2021 and 2022 DIDF). We see that the total known MWs loads have grown in this period. As mentioned before, the known load projects in the first few years are primarily driven from by EV charging station loads and cannabis cultivation, in addition to commercial and industrial loads.

Figure 2-12: PG&E Total Known Loads (w/o adjustment) for Past Two DIDF Cycles in MWs



San Diego Gas & Electric

SDG&E's approach for treating known load projects is similar to PG&E's. However, unlike PG&E, SDG&E does not discount the known load project amounts. SDG&E models 100% of the known load projects in the year in which they are forecasted to occur based upon customer requests. SDG&E also adds economic load growth projects to their forecast when the cumulative known loads in any given year is less than the cumulative IEPR forecast for that year. The process that SDG&E uses for handling known loads is discussed in detail in the SDG&E 2022 IPE DPAG report.

The annual and cumulative load growths due to known load projects and economic load additions, as well as the IEPR forecasts are shown in Figure 2-13 and Figure 2-14 respectively. As seen in Figure 2-13, the annual load growth modeled in the GNA is higher than the values in the IEPR forecasts for only the first year of the study period. On a cumulative basis, we see in Figure 2-14 that the loads used in the GNA are also higher than those from the IEPR only for the first year of the study. The known load projects in the first few years are primarily from new commercial loads including business, transportation, hospitals, parking, military, and farming. A breakdown of the known load projects by customer type can be found in the SDG&E 2022 IPE DPAG report.

Figure 2-13: SDG&E Annual known load growth, economic load growth and IEPR forecast

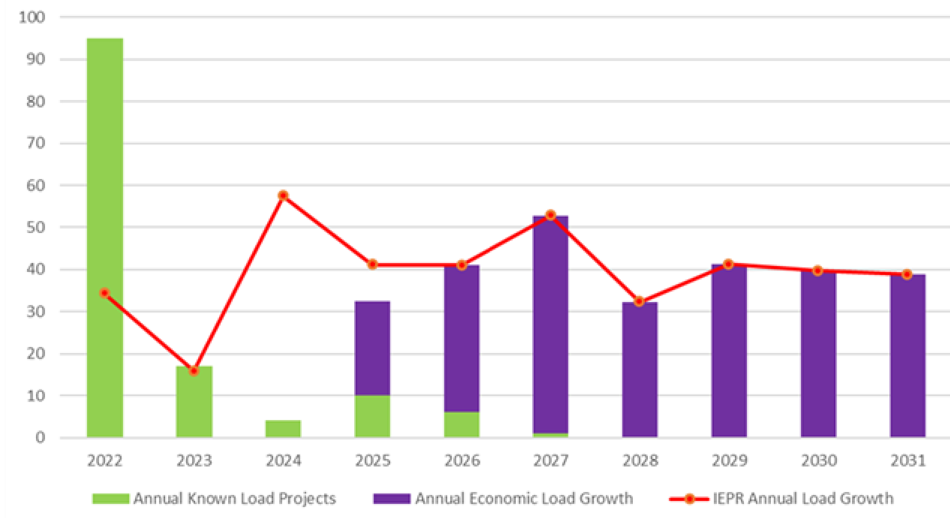
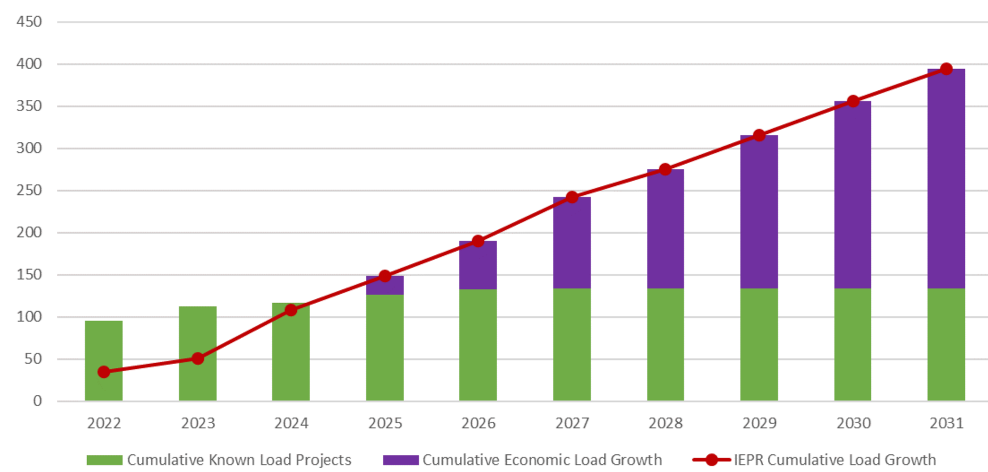


Figure 2-14: SDG&E Cumulative known load growth, economic load growth and IEPR forecast



SDG&E Known Load Project Trend

The total known load additions for the 10-year forecast period increased from 114 MW in the 2020 DIDF to 155 MW in the 2021 DIDF as shown in Figure 2-15. In the 2022 DIDF, the total known loads dropped to 133 MW as shown in the figure. However, known loads specifically identified as transportation-related grew in absolute terms from the 2021 DIDF to the 2022 DIDF. Figure shows transportation-related known loads as a percentage of the total known loads for the 10-year forecast period for the past two DIDFs.

Figure 2-15: SDG&E Total Known Loads for Past Three DIDF Cycles in MWs

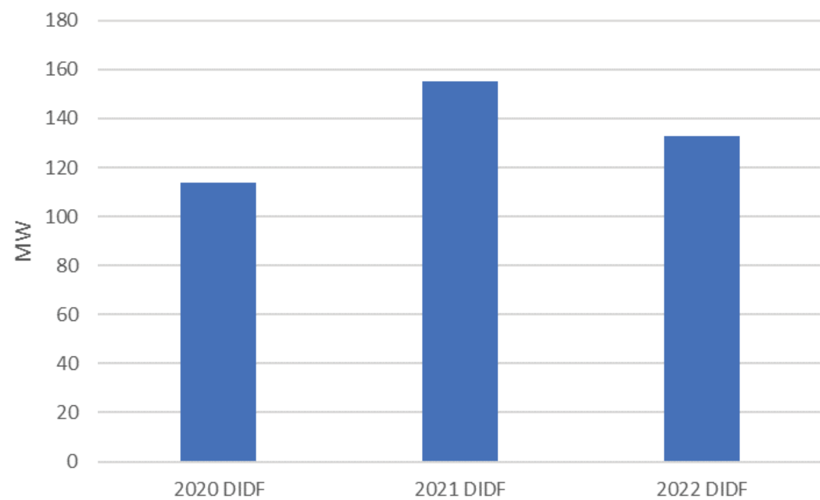
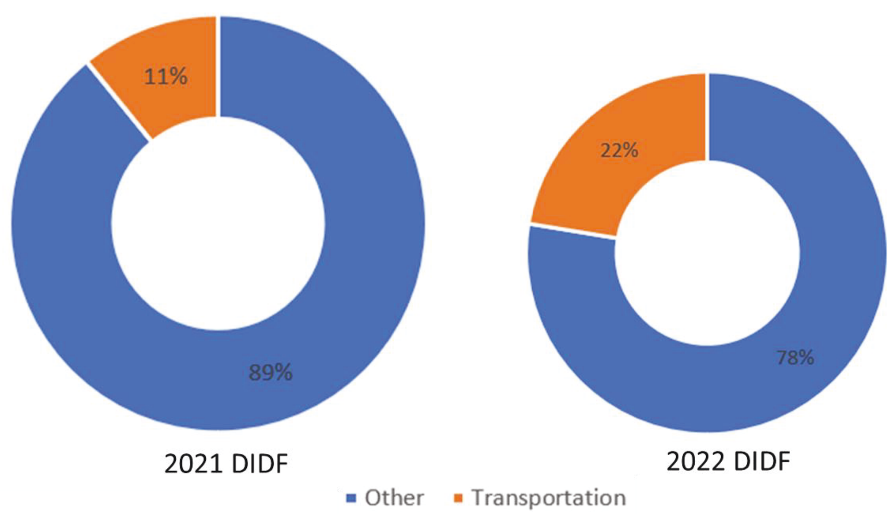


Figure 2-16: SDG&E Transportation-related Known Loads as a Percentage of Total Known Loads



2.3. Observations, Conclusions, and Recommendations

The IPE makes the following observations regarding the methodology used by the three utilities in the treatment of known load projects in the GNA. Some of this material is similar to material in the 2022 IPE Post DPAG Report.

- SCE used both embedded and incremental known load growth projects in their GNA load forecasting. The incremental known loads resulted in load growth that exceeds the CEC IEPR load growth in the 2022 DIDF cycle for the first 6 years of the 10-year planning horizon (and for a small load in year nine). SCE discounts their incremental known loads for diversity but not for uncertainty.

- SCE has been working with the CEC toward including all known loads in the CEC IEPR which would reduce or eliminate the need for SCE to utilize incremental known loads.
- PG&E and SDG&E use known load projects in their GNA that exceeded the annual CEC values in the early years (two years for PG&E and one year for SD&E) but match the cumulative load growth in the CEC IEPR over the 10-year planning period. PG&E applies an uncertainty discount to its known loads while SDG&E does not.
- We observe that having known load growth data driven by customer requests has the potential to improve the forecasting accuracy for load growth because it includes detailed location information that allows the load growth to be located precisely on a circuit as opposed to other load disaggregation methodologies that use much less precise econometric parameters to disaggregate load growth.
- We observe that known load data sets that extend out four years or more provides for more accurate planning than data sets that include only a few years of known loads.
- As a result of including known loads, in the 2022 GNA, the annual load growth is higher than the IEPR annual forecast value for the first 6 years for SCE, for the first 2 years for PG&E, and for the first year for SDG&E.
- In the 2022 GNA for all three utilities, the cumulative load growth in the first two years (2021-2023) is higher than the cumulative IEPR forecast for the same period. For SCE and PG&E, the cumulative load growth in the first five years (GNA study period) is higher than the cumulative IEPR forecast for the same period.
- For the PG&E and SDG&E approach, the higher load growth in the earlier years of the study due to known loads tends to push the needs into these years at the expense of fewer needs in later years. Since Candidate Deferral Opportunities (CDOs) are driven by needs primarily in years 4 and 5, this could result in fewer CDOs when compared to a case where the annual IEPR forecasts for years 4 and 5 are used. This impact may increase as the number of EV known loads increase over time as a result of California's EV goals.

The IPE has the following recommendations regarding the treatment of known load projects in the GNA.

- <u>We recommend</u> that an approach similar to what is being employed by SCE be considered by PG&E and SDG&E. This will likely result in the 10-year cumulative load growth forecast used in the GNA exceeding the cumulative IEPR growth for the same period.
- As mentioned, with SCE's approach, the sum of the embedded annual known load projects and economic loads do not exceed the annual IEPR forecast. As long as the utilities' coordination with the CEC results in the CEC accounting for/agreeing with the incremental known load projects in future IEPR forecasts, the result will be that all three utilities will use a similar process to reflect embedded and incremental loads. Following this recommendation will avoid the impacts of forcing the cumulative 10-year GNA load growth to be equal to or less than the 10-year cumulative IEPR load growth.

- We recommend that the IOUs review their use of discount factors to capture known load uncertainty in the 2023/2024 DIDF cycle.
- In the 2022 IPE Post DPAG report we recommended that given the importance of how known loads are implemented in the future, especially incremental loads, we recommend that in addition to maintaining up-to-date known load project databases and sharing them with the CEC, the IOUs report data sufficient for someone to track whether specific known load projects materialize (e.g., unique project identifier, impacted circuit, initial service request date, load amount, and expected online date). The ongoing implementation of that recommendation is discussed in Section 4 of this report.
- We recommend that the utilities collaborate (or continue to collaborate) with the CPUC and CEC on improving the IEPR forecasts by exchanging information on modelling and assumptions used in the utilities and the CEC's their respective load forecasts. The objective of this collaboration would be to capture all known loads in the CEC IEPR load forecasts.
- We observed that EV customer driven known loads are valuable to planning and that the utilities efforts to engage developers and stakeholders (described in Section 7) will likely increase the visibility of EV known loads in the early years of the planning period. However, we conclude that there is likely a limit in the number of EV known loads in the middle to latter part of the 10-year forecasting horizon due to developer uncertainty regarding the location of their projects. Through their interaction with EV load customers and analytical (adoption) studies, the utilities will be gaining insight into the EV community needs that may not be able to be directly used in the current utility DPP processes because they do not result in a customer request driven known load. For needs that can be met with short term utility upgrade projects this may not be an issue, but for needs that require longer term utility projects (e.g., addition of a new substation) it may not allow sufficient time to construct these longer lead time utility projects.

  To address this issue, we recommend the CPUC and IOUs consider a scenario type planning approach be added to the current DPP methodology to use the additional insights gained through increased utility engagement with developers and additional analysis to assess, for example, if there are some long lead time utility projects that are needed under a range of future EV scenarios.

3. Prioritization Methodology for Pilot Project Selection

3.1. Background

The February 11, 2021 Integrated Distributed Energy Resources (IDER) Decision (D.) 21-02-006 introduced the Partnership Pilot and the Standard Offer Contract (SOC) Pilot and streamlined the Distribution Investment Deferral Framework (DIDF) Request for Offers (RFO). This decision requires IOUs to recommend at least one Tier 1 and two Tier 2/3 projects for the Partnership Pilot, which is only open to behind-the-meter (BTM) DER technologies. In addition, IOUs are required to recommend at least one Tier 1 project for the SOC pilot, which is only open to in-front-of-the-meter (IFOM) DER technologies.

The ALJ's June 16, 2022 DIDF reform required each utility to develop, document, and implement a quantitative ranking method for the Standard-Offer-Contract pilot and Partnership Pilot project selection in their 2022 Grid Needs Assessment/ Distribution Deferral Opportunity Report (GNA/DDOR) filings. The ruling suggests that qualitative measures may also be applied by the utilities as a secondary factor but must be fully documented and described in the GNA/DDOR filing.

In this section, the qualitative and quantitative methods used by the three utilities for identifying and ranking the partnership and SOC pilot projects are summarized and their salient features are highlighted.

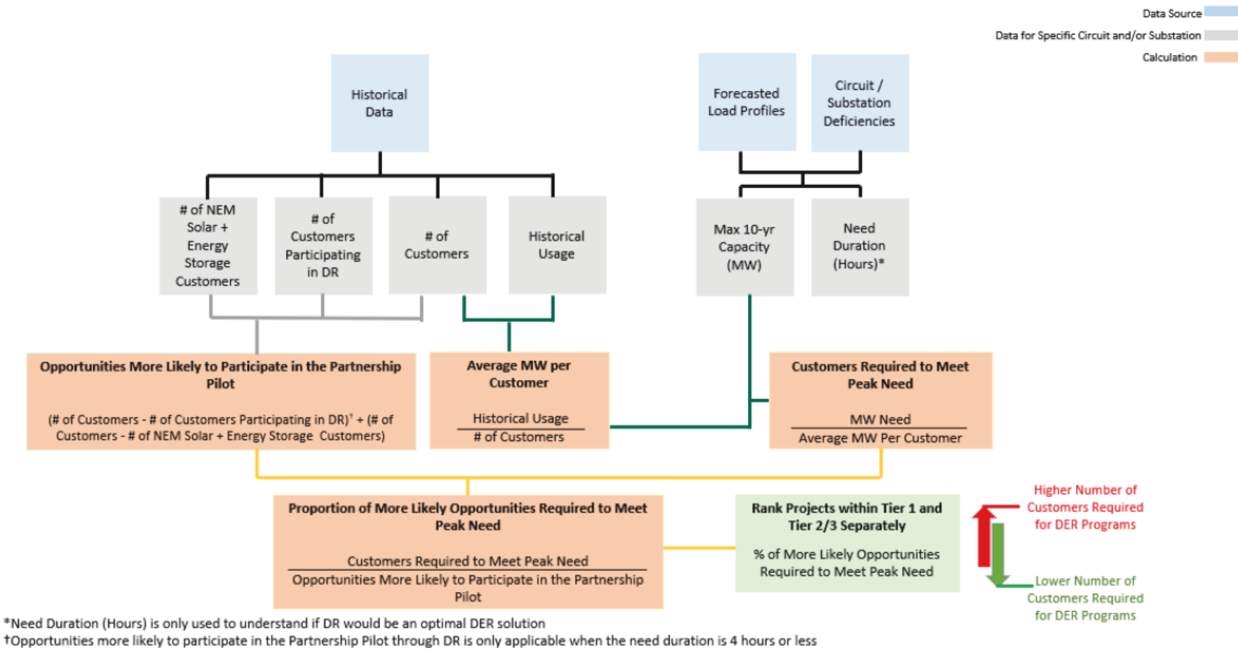
3.2. Pilot Project Prioritization Methodology for the three IOUs

Southern California Edison

<u>Partnership Pilot</u>

SCE has used the same methodology for selecting projects for the three different sourcing mechanisms, i.e., the RFO, the SOC pilot and the partnership pilot, in the past two DIDF cycles. The methodology for Partnership Pilot program selection is detailed in their 2022 GNA-DDOR report and summarized below for convenience. Figure 3-1 is a depiction of the methodology as provided in the report. Overall, the selection methodology calculates a metric as the ratio of the number of customers required to meet a project's needs to the number of customers more likely participate in a program. Projects are then ranked 1 to X based upon these scores with lower scores ranked higher where X is the number of projects being considered for the Partnership Pilot.

Figure 3-1: Partnership Pilot Selection Process used by SCE



- For each CDO, the ratio of "Customers Required to Meet Peak Need" and "Opportunities More Likely to Participate in the Partnership Pilot" is calculated. The CDOs with a lower ratio get a higher rank for the partnership pilot selection.
- The "Customers Required to Meet Peak Need" is calculated as the ratio of the "MW Need" associated with the CDO and "Average MW per Customer".
- The "Average MW per Customer" is calculated as the ratio of "Historical Usage" of energy on the circuit and the "Number of Customers" on the circuit.
- Finally, the "Opportunities More Likely to Participate in the Partnership Pilot" is the number of customers available to participate in the program which is calculated using the following relationship:

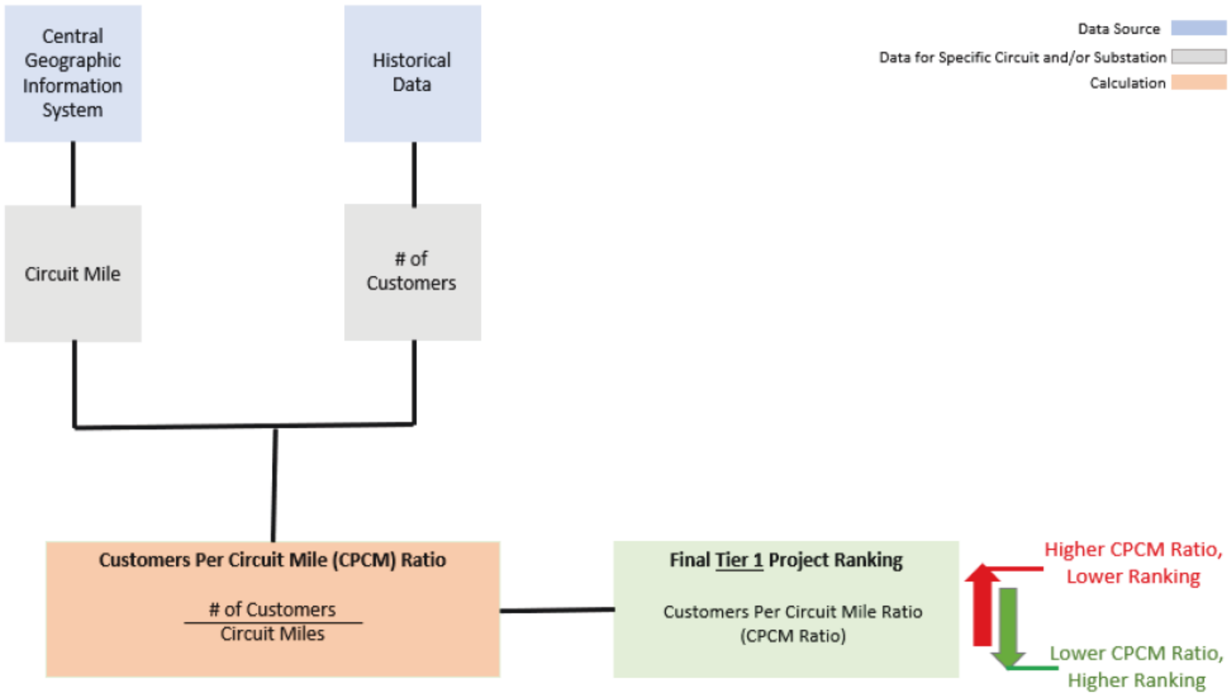
  (Number of Customers – Number of Customers Participating in DR – Number of NEM Solar + Energy Storage Customers)

SCE ranks and selects Tier 1 CDOs separately from Tier 2 and Tier 3 CDOs based on the above methodology.

<u>Standard Offer Contract</u>

Figure 3-2 shows the methodology used by SCE to rank the CDOs for the SOC pilot as provided in their 2022 GNA-DDOR report.

Figure 3-2: SOC Pilot Selection Process used by SCE



The methodology is based the calculation of the Customers Per Circuit Mile (CPCM) ratio, which is the ratio of the number of customers on the circuit with the need and the length of the circuit. A circuit with a lower ratio indicates fewer customers per circuit length which indicates the availability of land along the circuit for the development of a front-of-the-meter project, which tends to be larger and requiring more space than a behind-the-meter project.

Pacific Gas & Electric

Partnership Pilot

PG&E has used the same methodology for selecting projects for the three different sourcing mechanisms, i.e., the RFO, the SOC pilot and the partnership pilot, in the past two DIDF cycles. This methodology described below, uses a combination of qualitative and quantitative factors. The qualitative factors used in the selection of the Candidate Deferral Opportunities for the Partnership Pilot are given below.

1. At least one Tier 1 deferral opportunity and two Tier 2 or Tier 3 deferral opportunities selected consistent with the CPUC requirements.
2. Candidate Deferral Opportunities that could demonstrate Ratable Procurement (e.g., opportunities with low to moderate capacity needs that have incremental procurement goals).

3. Candidate Deferral Opportunities where Ratable Procurement could potentially address the challenge of changing distribution system needs and risk of over and under procurement.
4. Candidate Deferral Opportunities with grid needs occurring within two to five years of Pilot launch.
5. At least one deferral opportunity with a grid need forecast 4 to 5 years out to ensure the subscription period was sufficiently long in duration to test payments.
6. Clusters of deferral opportunities and planned investments.
7. Planned investments that service Disadvantaged Communities (DACs).

The ratable procurement opportunities (discussed in #2 above) are identified using a quantitative methodology where the trend of the need for all the CDOs are plotted and analyzed. Only CDOs that have needs that increase over time are short-listed for the Partnership Pilot. In addition, CDOs that have any flags or have at least one need that spans a 24-hour period are also removed from the list of projects identified for procurement.

<u>Standard Offer Contract</u>

The selection of the CDOs for the SOC Pilot is based on the following qualitative criteria:

1. At least one Tier 1 Candidate Deferral Opportunity selected consistent with the CPUC requirements.
2. A single Grid Need location to defer the Candidate Deferral Opportunity, in order to facilitate a single Point of Interconnection for an In-Front-of-the-Meter (IFOM) DER solution.
3. Indications that there is sufficient capacity at the location of the Grid Need for a DER to charge from the grid, so that IFOM DERs (including energy storage) may be able to charge from the location of need. PG&E notes that this assessment is only indicative, and the DER solution would still need to pursue the interconnection process.
4. Earlier In-Service Dates to test the impact of the SOC pilot on the ability of DERs to meet the In-Service Date.
5. Candidate Deferral Opportunities with larger Grid Needs (MW), as those needs may be most appropriate for Utility-Scale IFOM DER solutions.

The capacity for a DER solution to charge from the grid (#3 above) is identified quantitatively using a charge constraint score for each CDO. This score in percentage informs of the ability of the DER to charge during the hours when it’s not expected to be operated. A high score indicates that there are sufficient hours during which the resource can change. A low score indicates that there may not sufficient hours or capability on the circuit to charge. This might often be the case when the need is driven by underground cable and duct bank temperate constraints which prevents the resource from charging during off-peak hours. As before, CDOs that have any flags or have at least one need that spans a 24-hour period are also removed from the list of projects identified for procurement.

San Diego Gas & Electric

Partnership Pilot and SOC Pilot in the 2020-2021 DIDF

SDG&E had only two Tier 1 CDOs in the 2021 GNA-DDOR cycle, the first year when the utilities were required to propose projects for the two pilots. Since there were only two Tier 1 projects, SDG&E selected one of the projects for an SOC Pilot and the other for a Partnership Pilot based on the geographical location of each grid need and the size of the need. SDG&E chose one of the CDOs for a partnership pilot (i.e., BTM resources) since there were more customers on the circuit with the need, as well as the need was small and growing over time. SDG&E chose the other CDO for the SOC pilot since the circuit with the need served large customers that were spread out on the circuit. The need associated with this CDO was also relatively larger (in MW) than the one that was chosen for the partnership pilot. It appears that SDG&E's selection in the 2021 DIDF cycle was made based on an observation of the geographical location of each grid need and the size of the need and not a strictly quantitative selection methodology since only two CDOs were involved.

Partnership Pilot and SOC Pilot in the 2021-2022 DIDF

The ALJ's June 16, 2022 DIDF Reform order required that each utility develop, document, and implement a quantitative ranking method for the Standard-Offer-Contract pilot and Partnership Pilot project selection in their 2022 Grid Needs Assessment/ Distribution Deferral Opportunity Report.

SDG&E offered a possible methodology for selecting the SOC and Partnership Pilot projects and that methodology is discussed below.

The methodology for selecting the pilot projects involved choosing those CDOs located in areas with comparatively high income, which were at comparatively higher risk of fire-related outages, and which reflect the tiering from the Prioritization Metrics Workbook. This methodology is based on the application of quantitative metrics as well as qualitative criteria. A brief summary of the quantitative process offered by SDG&E is given below.

1. Calculate average annual household income (in thousands of dollars) for the ZIP codes impacted by the CDO.
2. Use SPARC GIS data to match the geographic locations impacted by the CDO to CPUC Fire-Threat codes (threat codes are 1 – 3).
3. Compute a Pilot Assignment Metric for each CDO. Pilot Assignment metric = (Average Income X Risk Score)/(Prioritization Metrics Workbook Tier).
4. CDOs with Pilot Assignment Metric greater than 83 will be subject to deferral through the SOC Pilot or Partnership Pilot.

In the 2022 DIDF cycle, there were no CDOs identified by SDG&E. However, there was one CDO from the 2021 cycle (that was recommended for the SOC pilot in 2021 and received no offers) that was recommended for deferral through the partnership pilot. Since the ALJ's June 16, 2022 DIDF Reform order required that each utility develop a pilot project selection process in their 2022 Grid Needs

Assessment/ Distribution Deferral Opportunity Report, SDG&E offered a process that could be used for selecting the pilot projects. The offered process was not actually used by SDG&E to select among CDOs for the 2022 DIDF cycle since, as mentioned previously, there was only one CDO that was recommended for the partnership pilot.

3.3. Observations, Conclusions, and Recommendations

The three IOUs employ different methodologies for selecting projects for the SOC and partnership pilots. SCE and PG&E have used their methodologies to select pilot projects in the last two DIDF cycles, whereas SDG&E has not used its most recently proposed methodology since they have not had more than two CDOs that have passed the technical and timings screens in the last two DIDF cycles. So, SDG&E has had no experience using of their offered approach.

For a successful Partnership Pilot project, having a sizeable population of residential and commercial customers with a potential for adopting behind-the-meter DERs is one critical element. In this regard, SCE's methodology attempts to rank projects on differences in this critical population by directly estimating the number of potential customers on the circuits with need by calculating the "Opportunities More Likely to Participate in the Partnership Pilot" metric[5], which is the number of customers available to participate in the program. In the 2020-21 DIDF, PG&E's methodology is primarily based on experimenting with various need/project types - i.e., identifying ratable procurement opportunities and identifying projects with low to moderate capacity needs that have needs that increase over time. While this is important, the IPE believes that selecting the projects, at least in part, should be based on supply side, i.e., having a sizeable population of residential and commercial customers with a potential for adopting behind-the-meter DERs is critical to success.

For a successful SOC pilot, having land in the vicinity of the circuit for siting a FTM project is important. SCE's methodology uses the Customers Per Circuit Mile (CPCM) ratio as a proxy for land space available along the circuit. PG&E's methodology is based the ability of the DER (FTM energy storage) to charge during the hours when it's not expected to be operated for load relief. The IPE believes that both these factors (space and ability to charge) should be given consideration in the selection of projects for the SOC pilot. The IPE would also like to suggest that the utilities explore using their GIS data to produce a score for the availability of land in the vicinity of the circuit in addition to using a proxy such as the CPCM ratio.

As mentioned previously, the selection methodology offered by SDG&E has not been tested before. SDG&E has proposed a single methodology for selecting both the SOC and partnership pilot projects which uses an absolute threshold value for selection. As mentioned above, the considerations for a Partnership Pilot project are usually different from those for an SOC pilot. SDG&E's offered

[5] The calculation used by SCE to estimate the number of potential customers, i.e., (Number of Customers – Number of Customers Participating in DR – Number of NEM Solar + Energy Storage Customers, has been discussed in prior DPAGs. SCE excludes the existing NEM solar+storage customers as potential participants in the pilot program since the operation of their storage systems may already be optimized for other services while it might be possible for these existing storage resources to provide NWA service by providing them with the right incentives

methodology would select CDOs for the SOC pilot and Partnership Pilot considering the Tier level of all CDOs; i.e., all things being equal, CDOs in Tier 1 would have a higher score than CDOs in Tier 2 which would have a higher score than CDOs in Tier 3. SDG&E did not offer a separate selection process for Tier 1 CDOs and another for Tier 2/3 CDOs. According to the Commission-adopted staff proposal at least one Tier 1 CDO is to be selected for the Partnership Pilot, and at least two Tier 2 and/or Tier 3 CDOs are to be selected for the Partnership Pilot[6]. The staff proposal does not indicate what should happen if there is only one Tier 1 CDO and no Tier 2/3 CDOs, which was, initially, the situation for cycle 1 of SDG&E's Partnership Pilot. Although not described in SDG&E's August 15, 2022 GNA/DDOR, SDG&E has subsequently indicated to the IPE that if there were multiple Tier 1 and Tier 2/3 CDOs, the Tier 1 CDO with the highest score, and the two Tier 2/3 CDOs with the highest scores among all Tier 2/3 CDOs, could be selected for use in the Partnership Pilot.

Finally, as discussed previously, SDG&E's offered selection process appears to favor pilot projects (SOC and partnership pilots) in high income communities with a high fire threat. The rationale for emphasizing these factors in the selection process for both pilots was not provided by SDG&E in its August 15, 2022 DDOR. SDG&E has since indicated to the IPE that it used (i) customer income under the theory that wealthier customers would be in a better financial position and therefore more likely to invest in DERs, and (ii) fire threat district codes under the theory that customers subject to higher risk of outages due to fires would be more likely to support the addition of DERs since this generating capacity could, in theory, provide customers with electric service during periods when electric service from the utility would not be available

[6] Commission-adopted staff proposal at p. 11. - "All pilot projects will address grid needs identified through the annual GNA/DDOR filings. Within every GNA/DDOR filed during the pilot period, Staff proposes that the IOUs continue to identify at least three deferral opportunities to pilot the CECI [Partnership Pilot] (i.e., one Tier 1 and two Tier 2/Tier 3). All other Tier 1 opportunities should be proposed for DIDF RFO or the SOC. If the IOUs do not identify any deferral opportunities in the GNA/DDOR, the IOUs would be required to select at least three planned investments that pass the technical screen and have grid needs that occur within two to five years."

4. Known Load Tracking Dataset

4.1. Background

The CPUC issued a ruling on June 16, 2022 that set forth a requirement for utilities to report data in their 2022 GNA/DDOR filings that is sufficient to track known load growth projects included in their DPP process. Listed below is an excerpt from the June 16, 2022 ruling related to the tracking data to be provided by the Utilities.

> " It is reasonable to facilitate tracking of known loads year after year to determine if they materialize. It is important to begin such tracking in the 2022 GNA/DDOR filing, with additional improvements in future years. Accordingly, as recommended by the IPE, Utilities shall include a spreadsheet listing of all Known Load Projects with their 2022 GNA/DDOR filing. Unlocked Excel spreadsheets shall be provided to the service list in R.21-06-017. If confidential information is included, a public version shall be provided (also in unlocked Excel files). Further, Utilities shall report data sufficient to track, over time, whether specific known load projects materialize.
>
> The data shall include a unique project identifier, impacted circuit, initial service request date, load amount, current expected in-service date or indication if service request was cancelled, if appropriate, and type/category of load and, if appropriate, the actual date service was initially provided and the amount. For SCE, the spreadsheet shall indicate whether each project was classified as an incremental or embedded known load project as defined by SCE.
>
> The data to track shall be selected by Utilities as appropriate to facilitate an annual review of CEC demand forecast accuracy and planning improvements for the next forecast. The tracked data will be reviewed during the 2022 DPAG and by Energy Division. Stakeholder comments on the data selected for tracking are requested for consideration in the 2023 reform process."

We understand from the ruling that the purpose for requesting the data is to track if known loads that are used in the DPP forecasting process (that are driven by customer requests for service) actually "materialize." We assume that to track whether a known load materializes means to track the status of known loads over time from its initial use in the DPP until 1) the known load is implemented (requested service is provided to the customer) or 2) the request for service is terminated by the customer, or 3) the customer requests a change in the amount or timing of the service.

The status that needs to be tracked once a known load is first used in the annual DPP process (and first included in the annual Tracking Data provided by the utility) includes information that would be included in the Tracking Data submitted in subsequent years. This status data includes:

1. how the known load amount of service requested was increased or decreased by the customer relative to the amount of service reported in the last annual Tracking Data provided by the utility,
2. how the date for service requested by the customer is delayed or accelerated by the customer relative to the date for service reported in the last annual Tracking Data provided by the utility,
3. if the requested service by the customer is cancelled by the customer,
4. if the service has been provided since the last data submittal by the utility and if the amount of service provided is different than the amount reported by the utility in its previous annual Tracking Data report, and
5. any other changes to the data provided by the utility in its Tracking Data (i.e., change in the type/category of load to be served).

Providing the data listed above would allow the following aggregate values to be calculated each year following receipt of the most recent annual Tracking Data – in each case these known load metrics would be calculated for each of the ten years of the DPP forecast horizon unless otherwise noted:

1. Total of all known loads (MW or MVA and number of known loads)
2. Total of all known loads by category and type (MW or MVA and number of known loads)
3. Annual Change (relative to the previous Tracking Data submitted by the utility) in total of all known loads (MW or MVA, %[7] and number of known loads)
4. Annual Change (relative to the previous Tracking Data submitted by the utility) in total of all known loads and also broken out by category and type (MW or MVA, % and number of known loads)
5. Service Amount Deferred (MW or MVA) (MW or MVA, %)
6. Service Deferral Rate Total (%)
7. Service Deferral Rate by Category and type (%)
8. Cancellation Rate Total (%)
9. Cancellation Rate by category and type (%)
10. Service Request Amount Increase Rate Total and Average Amount (%, MW or MVA)
11. Service Request Amount Increase Rate by category/type and Average Amount (%, MW or MVA)
12. Service Request Amount Decrease Rate Total and Average Amount (%, MW or MVA)
13. Service Request Amount Decrease Rate by category/type and Average Amount (%, MW or MVA)

Listed in Appendices A, B and C. are description of the data provided by each of the utilities. Based upon this information, the IPE believes that all of the above aggregate statistics can be calculated for all three utilities except for metrics that that break out the data by category and type because each of the utilities interpreted the requirement to report category and type differently. What would be

[7] The % which is included in a number of these metrics would be developed by taking the percentage of the value (in this case total MW or MVA (depending upon what the IOU reports) has changed)) to the total known load amount. In other words, the % of the total MWs that were changed in the most recent submitted data compared to the previous cycle/years submitted data.

most helpful in the future would be if all utilities reported type of customer (residential, commercial and industrial) as well as the category of the customer load (Agricultural Water Pump, Mega Tract Homes, Cultivation, Medium / Heavy Duty Commercial EV Charger, etc.). This will allow analysis of the above metrics to determine if some categories of new loads are less certain to materialize than others and therefore treated accordingly in the DPP process. Further it would be useful if all three utilities used the same list of potential categories. In the recommendation section we recommend this change be included in the next DIDF reform decision.

The Tracking Data could also potentially be used to develop metrics based upon changes to customer requests as opposed to the aggregate metrics referred to above. These second set of metrics would reflect how customer requests change over time from the initial customer request (defined as year 1 for that request) to subsequent changes in year 2, 3 etc. until the service is provided, or the request is cancelled. The aggregate metrics referred to above, calculate changes that occur on a calendar year basis. To develop the customer request-based metrics would require that there is a way to connect, from year to year, known loads and known load components if there are any[8]. Based upon our understanding, SCE's data will use a unique identifier for all components of a customer load request so this connection will be possible with their data. Based upon our discussion to date it appears that this will also be possible with PG&E and SDG&E even though their customer requests that have multiple load components are not linked together in any given year, because each individual load components can be tracked from year to year (while the load adjustments are active according to PG&E). Calculating metrics on a customer request basis allows tracking when changes are made – i.e., in the first year after service is requested or the second year, etc. Thus, the following metrics could be calculated:

1. Service Deferral Rate (%) in first, second, third and fourth year after initial inclusion as a known load by type and category of known load.
2. Service Cancellation Rate (%) in first, second, third and fourth year after initial inclusion as a known load by type and category or known load.
3. Service Reduction Rate (%) in first, second, third and fourth year after initial inclusion as a known load by type and category or known load.

4.2. Observations, Conclusions, and Recommendations

- We recommend that all utilities include data on customer type (commercial, residential, industrial) and customer load category (Agricultural Water Pump, Mega Tract Homes, Cultivation, Medium / Heavy Duty Commercial EV Charger, etc.).

[8] PG&E and SDG&E's data includes a data record for the customer's basic requested service and will also include an additional data record (with a different unique identifier) for each increase in service that is requested over time. For example, if the service request is for 1 MW in 2026 and grows to 1.5 MW in 2028 there is a second data record that reflects a new load of 0.5 MW in 2028. This is often referred to as phasing of service or as project phases. In addition, if the project is broken down into sub-projects, for example service provided for two housing tracts, the data submitted will include a separate data record with its own unique identifier for both tracts. In this report, the term component is used to describe the secondary data records for growth of service and for multiple sub-projects.

- <u>We recommend</u> that all three utilities use the same customer categories in their tracking data. The list used by SCE (shown in Appendix A) may be a good starting point for discussion among the IOUs to agree on a common set of categories.
- We observe that SCE provided the five-year total amount of service being requested while PG&E and SDG&E provided annual values. Annual values would be needed to calculate almost all of the metrics discussed earlier in this section. Therefore, <u>we recommend</u> that SCE include annual amounts of service requested in future tracking data submittals.
- We observe that PG&E did not provide the actual load amount and the actual in-service date in their known load tracking data. Based on subsequent discussions with PG&E, it is our understanding that PG&E will try to provide this data in future cycles.
- We observe that for the "Initial Service Request Date" field in the known load tracking dataset, SDG&E provided the "date customer made the request" and not the "initial in-service date initially requested by the customer." If possible, we recommend SDG&E provide the "initial in-service date initially requested by the customer" in the next cycle.
- Based upon the information provided, and assuming that all three utilities use the same set of customer categories, we believe that the data provided by the three utilities and the data planned to be provided in the future should allow the metrics listed above to be calculated. We believe this data should allow for tracking known loads over time to help answer the question: "Did known loads incorporated in the DPP materialize, and if not, how many were deferred, cancelled or modified?"
- Initially the IPE had a preliminary recommendation in the 2022 Post DPAG Report that the IOUs develop a report that uses tracking data to develop metrics that could help answer the questions listed in the previous bullet. After some discussion that recommendation was modified to require the IOUs to provide data with the assumption that stakeholders could develop metrics using the data or wait to read the IPE's DPAG and Post DPAG Reports to see the metrics developed by the IPE using the IOUs tracking data. Given the complexity of the tracking data submittals and the fact that all three companies will report the data differently because of differences in their business processes and IT systems, the IPE raised the alternative wherein the IOUs would provide a narrative summary report that includes metrics they calculate based upon their tracking data and the implications of those metrics. The narrative summary could, for example, include the metrics above. Under this alternative, stakeholders would not have to wrestle with the data complexities of three different data sets, instead they would receive the metrics and the implications of those metrics in the IOUs reports. Only the IPE would have to deal with the data complexity in its annual V&V review. This alternative was discussed with the utilities and the Energy Division (ED) and the ED felt that given the role of the IPE is one of verification and validation that it was appropriate for the IOUs to provide a summary report which includes a narrative and metrics developed using the tracking data and that the tracking data would also be provided in the GNA/DDOR filings for those stakeholders who may want to perform their own metric analysis. For this reason, <u>we recommend</u> that the utilities provide the tracking data as discussed in the following section and that they also include a narrative and metrics in their GNA/DDOR reports.

5. Load Forecast Uncertainty Metric in Project Prioritization

5.1. Background

The current Joint Prioritization Metrics Workbook has been in use in its present form for three cycles and before that, utilities used a utility specific methodology to rank candidate deferral opportunities (CDO). To meet CPUC requirements, the various methods used over time by the utilities always included a Forecast Certainty Metric in the prioritization process. Currently, the three utilities use a Forecast Certainty metric in their prioritization process and each is different from the others. The Forecast Certainty Metric is one of three metrics used in the prioritization process. The Joint Prioritization Metrics Workbook Template which places CDOs into three tiers based on a step-by-step process, uses three metrics that in turn are developed using sub-metrics. For the Forecast Certainty Metric, there are two sub-metrics, 1) Grid Need Certainty and 2) Year of Need. These sub-metrics are used to develop a quantitative ranking of the CDOs from 1 to X where X is the maximum number of CDOs. The sub-metric for Year of Need is the same for all three utilities although some of the utilities have chosen not to use it in this cycle. The sub-metric for Grid Need Certainty is unique for each utility.

5.2. Methodology for Developing Forecast Certainty Metric by the three IOUs

Provided below is a high-level summary of the Grid Need Certainty sub-metric used by each utility as part of developing its Forecast Certainty Metric. A review of each approach is also provided.

5.2.1. Pacific Gas & Electric

According to PG&E's GNA/DDOR report, the Grid Need Certainty Score is developed from a forecast questionnaire (a summary of which is included as Appendix F in PG&E's DDOR report), which PG&E revised for this cycle. This questionnaire, completed by local distribution engineers, provides local engineering judgement potentially impacting the certainty of the forecast, such as the health and condition of assets and other activity in the area which may impact the forecast loading. The questionnaire is significantly different from the one used in the previous cycle.

In this revised questionnaire, there are five questions and the responses to these questions are each assigned a score on a 10-point scale. The overall Grid Need Certainty (GNC) score is the negative of the sum of these scores – the more negative the GNC score, the lower a CDO will be ranked and a lower project ranking will reduce the likelihood that a project will be recommended to proceed to competitive procurement through an RFO or an SOC or partnership pilot. The questions listed in PG&E's Appendix F are listed below (Q1 is the name of the project):

Q2: Is the area served by the project within two miles of (select one):

- 0 freeway or highway
- 1 freeway or highway
- 2 freeways or highways
- 3 freeways or highways"

Q3: Have you received an inquiry about new load growth application (e.g., fast charging connection or other loads) in the area that is not yet reflected in the load forecast?

Q4: If you've answered "Yes" in the previous question about new load growth application, please specify the type of load(s) below: (Typical responses that were include in Appendix F were - Commercial; Industrial; Residential; EV (e.g., DC Fast Charging); Cannabis; etc.

Q5a-e: What type of project is planned – a) New Substation, b) New Substation Transformer, c) Replaced Substation Transformer, d) New Circuit Breaker, e) Line Work Creates Tie?

Q6: What is the asset health risk based on condition for the project and all grid need locations

Discussion of PG&E Forecast Certainty Questions

Question Q2: This question is intended to capture the possibility of additional load growth in the area of the need (for the project in question) that could materialize due to new EV charging stations (which are assumed to locate near highways) that are not in the current load forecast. This would be the case if a developer has plans to add a commercial EV charging stations but has not yet applied for service or otherwise has reached the state of customer planning that PG&E requires before it would add the new load as a known load in their DPP process. Of the 18 CDOs in Appendix F of the 2022 GNA-DDOR report, the need "location" for 15 of the needs were close to 1 or more freeways. The scoring for this question was – a score of 10 for 3 freeways, a score of 6 for 2 freeways, a score of 3 for 1 freeway and a score of 0 for zero freeways.

What is not stated but implied is that if a DER were procured and new un-forecasted EV load developed such additional load could impact the need and possibly adversely impact the cost-effectiveness of the DER under contract.

Questions Q3 and Q4: These questions are intended to capture the potential for new load interconnecting in the area of "need". Scoring is 10 if the answer is Yes to Q3 and 0 if the answer is No. Q4 does not impact scoring directly instead it provides insight into the specific type of inquiry about new load growth application and is a follow up question to Q3. It is not clear what constitutes an "inquiry" that is referenced in the question or if the inquiry should exceed some threshold amount of new load. Again, what is implied is that if a DER solution were procured and this new un-forecasted EV load developed, such additional load could impact the need and possibly adversely impact the cost-effectiveness of the DER contract.

Question Q5: This question is intended to capture the correlation between the scope of the planned CDO project and the likelihood that it would be able to accommodate un-forecasted load increases in the future. From the entries in Appendix F, larger projects (i.e., projects that provide a larger increase in capacity) such as the addition of a new substation gets a higher certainty score since it's most likely to provide the largest amount of margin (capacity in excess of identified need) and thus be able to accommodate the largest un-forecasted increase in load. Scoring is as follows: – a score of 10 for a new substation, a score of 8 for a new substation transformer, a score of 6 for replacement of a substation transformer, a score of 4 for a new circuit breaker and a score of 2 for line work to create a circuit tie.

Question 6: This question is intended to capture the difference in asset health risk for assets in the area between the proposed project and a DER solution. We assume that the asset risk that is being considered is for assets that have a high risk of failure prior to the conclusion of the DER contract period.

Question 6: This question is intended to capture the difference in asset health risk for assets in the area between the proposed planned investment project and a DER solution. We assume that the asset risk that is being considered is for assets that have a high risk of failure prior to the conclusion of the DER contract period. We assume that because if the risk is beyond the DER contracting period that there is no difference in the risk of failure .

We believe that the rationale behind this question is that if there are assets with a high risk of failure that are being replaced by the proposed planned investment project and are continued to be relied upon under the DER solution, then under the DER solution if the asset fails during the DER contract period the failed equipment would need to be replaced, which could potentially make the DER project solution moot or less cost-effective. Scoring is as follows in the projects listed in Appendix F: A score of 10 is given to an asset if it's at high risk, 6 for medium risk, and 3 for low risk.

It would seem that if a planned investment project is not removing a piece of equipment from service as part of the project, then both the planned investment and DER solutions are relying on the same existing set of equipment. So based upon the description of the project listed in Appendix F (Q5a-Q5e, columns E – I) they would suggest that of the five types of planned investments only Replace Substation Transformer has a different risk since a transformer is being replaced with a new one as part of the planned investment project. For the other four types of projects (New Substation, New Substation Transformer, New Circuit Breaker and Line work to Create Tie) it would seem that both solutions are relying on the same existing set of equipment since nothing is being replace and therefore there is no difference in risk between the planned investment project and the DER solution for these types of projects. It does not appear that the scoring of risk used in Appendix F makes this distinction between planned projects that add equipment which do not change the equipment being relied upon and planned replacements that may remove a transformer that has a high risk of failure.

Observations, Conclusions and Recommendations Related to PG&E's Forecast Certainty Metric

- We observe that the Q2-Q5 questions appear to address capturing the potential for additional load materializing in the area of the need that is not currently in the load forecast.
- We observe that Q3 and Q4 are about inquiries for new load prior to an application for new service. We observe that there is no definition of what constitutes an inquiry or if there is a threshold level of new load (MW) referred to in the inquiry prior to answering Yes for this question. In the interest of transparency, <u>we recommend</u> that if they do not already exist that both of these (inquiry definition and threshold) are documented as part of the process used by planning engineers and are included in the GNA/DDOR.
- We observe that Q5a through Q5e which gives higher uncertainty scores to larger planned projects is not really a load uncertainty score but is a comparison of the ability of the planned project to accommodate new un-forecasted load without further upgrades compared to a DER solution's ability to accommodate new un-forecasted load with additional actions (DER additions or infrastructure additions).
- We observe that the scoring for question Q6 (asset failure risk) is not clear from the CDO scores in Appendix F in the PG&E GNA/DDOR. Based upon what we think the intent is of this question, it appears that only planned projects that replace equipment (i.e., substation transformer replacement) should be considered less risky than a DER solution. <u>We recommend</u> that if PG&E retains this question that it makes it clear how the question applies to each type of planned project and why.
- We observe that Q6 deals with risk of failure of equipment, and it seems that should be considering the risk of failure during the DER contracting period. If that is the case, <u>we recommend</u> that this should be made clear in the use of this question and also made clear that only equipment with a high risk of failure in the DER contracting period should be considered of having a high risk with respect to applying this question to develop uncertainty metrics.
- We observe that the five questions seem to be aimed overall to protect against the possibility of the need (kW deficiency) that drove the planned project in the first place increasing due to new customer service requests resulting in a need to take additional action (infrastructure and/or DERs) that may reduce the cost-effectiveness of the original DER solution. To reduce the chance of such a reduction in DER cost-effectiveness one would rank projects (Tier ranking) lower with higher uncertainty scores and thus reduce the potential for recommending a DER deferral for certain types of projects. This action (higher load uncertainty and lower tier ranking) here seems to be guarding against the possibility of a DER solution ending up being more expensive than the planned investment due to changed circumstances that could potentially occur after the DER contract is put in place.
- As a result of applying questions Q2-Q6 the following types of planned projects would be ranked lower and therefore have a lower chance of proceeding to procurement and ultimately having the project deferred by a DER:
    - Projects within 2 miles of a freeway
    - Projects in areas where there have been a customer inquiry for additional service (not necessarily EV service)

- Projects that add larger amounts of additional capacity which also tend to be the most expensive projects (i.e., new substations)
- Projects that replace equipment that has a higher risk of failure during the roughly next ten-year period

- We observe an un-intended outcome of the application of Q5 is the potential for projects that may have the highest Cost-Effectiveness Metric Scores would be given lower Forecast Certainty scores.

5.2.2. Southern California Edison

According to SCE's GNA/DDOR report, the Forecast Certainty metric methodology includes two sub-metrics - a quantitative sub-metric and a qualitative sub-metric. The quantitative sub-metric, Grid Need Certainty, is developed using a Level of Certainty questionnaire completed by planning engineers for each planned project. The qualitative sub-metric is Year of Need which is a flag that would be set if the project's operational date is after the threshold year set by utility. While this flag capability is included in the Joint Prioritization Workbook, SCE did not use this flag in this current cycle. As a result, the Forecast Certainty Score is equivalent to the Grid Need Certainty Score.

SCE Grid Need Certainty Metric

SCE bases the Grid Need Certainty Score on the numerical values developed using the Level Of Certainty questionnaire. The LOC questionnaire as shown in Table 5-1, includes seven sub-scores (rows in the table) and guidelines as to what status or stage a customer's project must complete to get higher sub-scores. The weight each sub-score has in the development of the overall score is shown in the far-right column. The overall Grid Need Certainty Score is the weighted sum of the seven sub-scores. The higher the Grid Need Certainty Score, the more certain that project is considered in SCE's prioritization of CDOs in its Joint Project Prioritization Metric Workbook.

Discussion of SCE Grid Need Certainty LOC Questionnaire

SCE's questionnaire is intended to capture the progress of a customer's project (new housing tract, commercial charging station, new cultivation site, etc.) toward completion by the customer for actions that it must complete and by SCE for actions it must complete. The customer actions are related to completion of an application for service, construction progress, permitting progress, provision of a load schedule and status of switchgear needed if any. The SCE actions are related to the status of the project design and whether the customer has agreed to the necessary additional equipment.

Observations, Conclusions and Recommendations Related to SCE's Forecast Certainty Metric

- We observe that each of the sub-scores in the LOC is intended to capture the progress of steps by the customer or by SCE that are necessary to complete the customer's project.

- We observe that as a result of the nature of the sub-scores that the overall Grid Need Certainty Score is a measure of what state of progress the project is at relative to completion and SCE being capable of providing service to the customer. In other words, we conclude that the SCE Grid Need Certainty Score can be considered as a measure of how likely the requested additional service (load) is to materialize.
- We have no recommendations at this time.

Table 5-1: LOC Questionnaire used by SCE

	Score	0	1	2	3	Weight
Customer Information	SCE Application for Service	N/A	Received	N/A	N/A	1
	Construction Status	Not Started	Grading	Constructi on Started/Exi sting Building	Construction Complete	3
	Low/High Voltage Switchgear	None	Design / Drawings Received	Approved	Authority Having Jurisdiction (AHJ) signoff / Installed on-site	2
	Load Schedule	None	Range Provided but no firm values	Received but not validated	Data Confirmed	1
	Status of Environmental Review or other Regulatory efforts	Not Started	In Progress / Not Required	Filed	Approved	1
SCE Information	Added Facilities	None	Customer Moving Forward	N/A	Added Facilities Agreement Complete	2
	Design Status	Not Started	In Preliminary Design	Final Design Approved	Customer Invoiced	1

5.2.3. San Diego Gas and Electric

According to SDG&E's GNA/DDOR report, the Forecast Certainty Score methodology includes a quantitative sub-metric and a qualitative sub-metric. The quantitative sub-metric, Grid Need Certainty is developed using a questionnaire completed by planning engineers for each planned project. The qualitative sub-metric is Year of Need which is a flag that would be set if the operational date of the planned distribution upgrade is after the threshold year set by utility.

Discussion of SDG&E Grid Need Certainty

According to SDG&E's GNA/DDOR report, the Forecast Certainty Metric is intended to give a relative indication of the certainty of forecast grid needs. SDG&E uses a Grid Need Certainty metric which is an SDG&E-specific, maximum grid need certainty score associated with a project. The quantitative sub-metrics are:

- Weather factor adjustment: SDG&E indicated that significant weather events can have a large effect on load. There is more forecast certainty in areas that have loads that are less weather sensitive.
- Customer-Specific Development: The need for the planned distribution upgrade project is a result of general or specific ("known loads") customer load growth.
- Historical Load: Compares forecast peak load to recent years' actual peak load.

SDG&E also included a qualitative metric which is used as a flag in the Joint Prioritization Metric Workbook:

- Year of Need: The earliest starting year among all assets associated with a project

Shown in the table below is how SDG&E scored its quantitative and qualitative sub-metrics:

Table 5-2: SDG&E Scoring and Ranking for Grid Need Certainty

Criteria	Higher Ranking	Lower Ranking
Weather factor adjustment	Average weather factor applied compared to overall system	Above-average weather factor applied compared to overall system
Customer-specific development	Numerous customer requests for new load	Fewer customer requests for new load
Historical load	Forecast peak with minimal variation from recent years' peak	Forecast peak with significant variation from recent years' peak
Year of Need	2025 needs	2026 needs

We can see that SDG&E's overall approach focuses on the uncertainty of the load that is driving the need for a project. That includes weather impacts, the number of customer requests driving the load, and historical load variability as part of the quantitative sub-metric and Year of Need for the qualitative sub-metric.

Observations, Conclusions and Recommendations Related to SDG&E Forecast Certainty Metric

- We observe that SDG&E considers both quantitative and qualitative factors that could impact if and when forecasted load will materialize.
- We observe that SDG&E does not consider the potential for un-forecast new load to materialize which might result in a DER solution's cost-effectiveness to be adversely impacted.
- We have no recommendations at this time.

5.3. Comparison of PG&E, SDG&E and SCE's Grid Need Certainty Metrics

Based upon the prior discussion we note that:

- PG&E's multi-question approach focuses primarily on the potential risk of new un-forecasted load developing, and secondarily, equipment failing after a DER contract is signed that might result in increasing overall cost for ratepayers. PG&E's approach does not appear to consider the risk of the load that is driving the need for a project not materializing and the potential for an unneeded upgrade being built resulting in increased ratepayer costs.
- SCE's LOC approach focuses on the risk of load that is driving a planned investment not materializing by ranking projects with low scores to reduce the potential for building an unneeded upgrade and as a result increasing ratepayer costs. SCE's approach does not include consideration of the potential risk of new un-forecasted load developing that might change the cost-effectiveness of a DER solution.
- SDG&E's questionnaire approach focuses on the risk of load that is driving a planned investment not materializing. To do that, it ranks projects lower that have low scores to reduce the potential for building an unneeded upgrade and as a result increasing ratepayer costs. SDG&E's approach does not include consideration of the potential risk of new un-forecasted load developing that might change the cost-effective of a DER solution. We note that all three approaches do not treat any reliability analysis or planning function differently, so we see no difference in the different approaches regarding the reliability of the service provided to its customers. What is different is how the approaches view the risk of increasing ratepayer cost.
- PG&E's approach focuses primarily on the risk that something un-forecasted might happen after a DER solution is put in place to make it less cost-effective (or not cost-effective); this could include a number of possible outcomes which are likely to be dependent upon each planned investment and the nature of the new load that materializes. Conceptually this could include the need to build the proposed planned investment or to procure additional cost-effective DERs, or a combination.

  PG&E's approach does not consider the potential of building a project that may turn out not to be needed because the load did not materialize.
- SCE and SDG&E's approaches focus on the risk that the load(s) that is driving the need for the project may not materialize and therefore the project may not be needed; their approach

does not consider if changes after a DER solution is put in place might adversely affect the DER solution's cost-effectiveness.

- It seems that the risk of customer load not materializing is present for each planned investment and should be considered especially for needs driven by one or just a few customers' new loads. Such customers plans could suddenly change with the economy or other factors resulting in deferral or cancellation of the service request which could potentially result in an upgrade been unneeded and an unnecessary increase in rates if not considered. This form of ratepayer risk can be somewhat reduced by monitoring the progress of developing the loads for which customers are requesting distribution service to ensure that those loads are still likely to timely materialize. .

6. Results of Load Forecasting Comparison

6.1. Background

Starting with the 2019-2020 DIDF cycle, based on the IPE's recommendations from the 2019 IPE report, all three IOUs were required to provide data for comparing the actual loads against the forecasts, adjusted to the same basis (1-in10) for a selected number of circuits. The provision of this data is intended to gauge the accuracy of the load forecasts (Step 19 of the IPE verification and validation process). Starting in the 2020-21 cycle, the utilities were required to provide this data for a statistically meaningful number of circuits (roughly 10% of all circuits) selected randomly. The analysis and recommendations presented here is based on two years of data gathered from the 2020-21 and 2021-22 DIDF cycles.

6.2. Actual Versus Forecast Load Comparison for the three IOUs

As mentioned earlier, as a part of Step 19 of the IPE V&V process, the utilities are required to provide the actual peak loads for selected circuits as determined in the current year's GNA (adjusted to 1-in-10) and a forecast of those peak loads from the prior cycle, also adjusted to 1-in-10. The sections below show a comparison of the actual versus forecasted loads for SCE and PG&E. While this data was provided by SDG&E as a part of Step 19, the actual peak load data provided was not adjusted for 1-in-10 weather conditions due to the normalization requirement not being clearly stated in the IPE's V&V plan. SDG&E will provide this normalized data in the next DIDF cycle.

Southern California Edison

A comparison of the actual and forecast load ((actual load-forecast load) expressed as a percentage of actual load) from the 2020-21 and 2021-22 DIDF cycles for SCE are shown in Figures Figure 6-1 and Figure 6-2 respectively. In both cycles, roughly 300 circuits were randomly chosen for this analysis.

The bars on the right side of the histogram plot show the number of circuits where the actual load is higher than the forecast load. Conversely, the bars on the left side of the plot show the number of occurrences where the actual load is lower than forecast. It can be seen that roughly 80% of the forecast errors (for example, 272 out of 335 circuits for the year 2021-2022 shown in Figure 2) have forecast errors in the range of -30% to +30%. It can also be seen that there is a slight bias to the right, i.e., there are more circuits with positive errors than negative errors. This means that the actual load is higher than the forecast more times than when it is lower than the forecast – of the 333 circuits, 227 or 68% had positive errors indicating that the forecast was lower than the actual.

Reviewing the data for the previous cycle (2020/2021), we also see a similar bias to the right (actuals greater than forecast) – of the 292 circuits, 166 or 56% have actuals greater than forecast. This shows a slight increase in the % of error bias from the 2020/2021 cycle to the 2021/2022 cycle.

Figure 6-1: Histogram of Load Forecasting Error for First Year Forecast – SCE 2020-21 DIDF

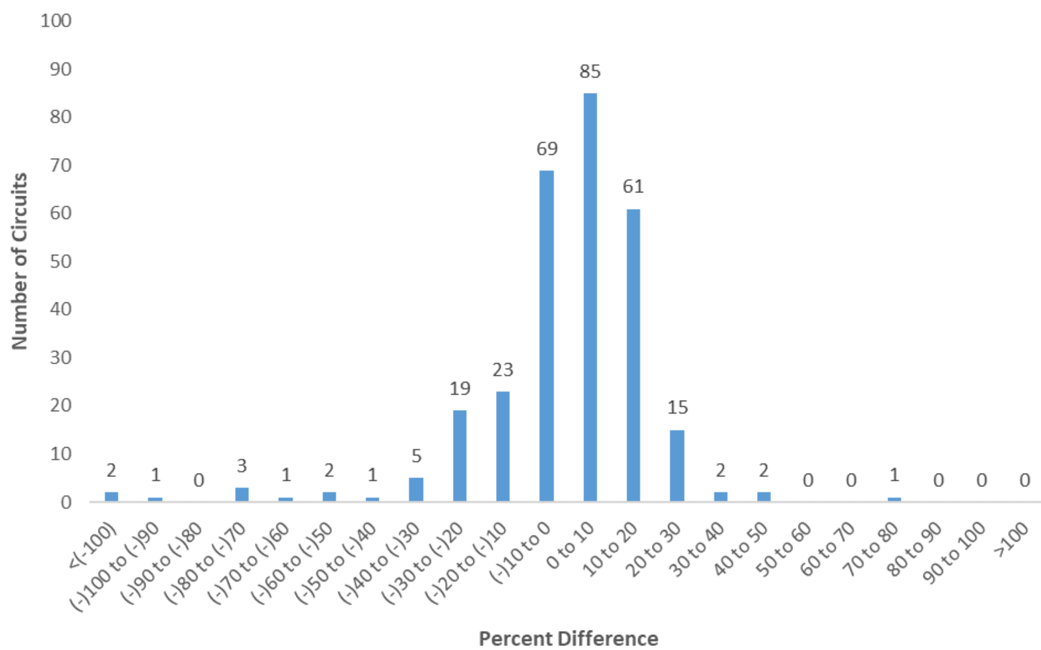
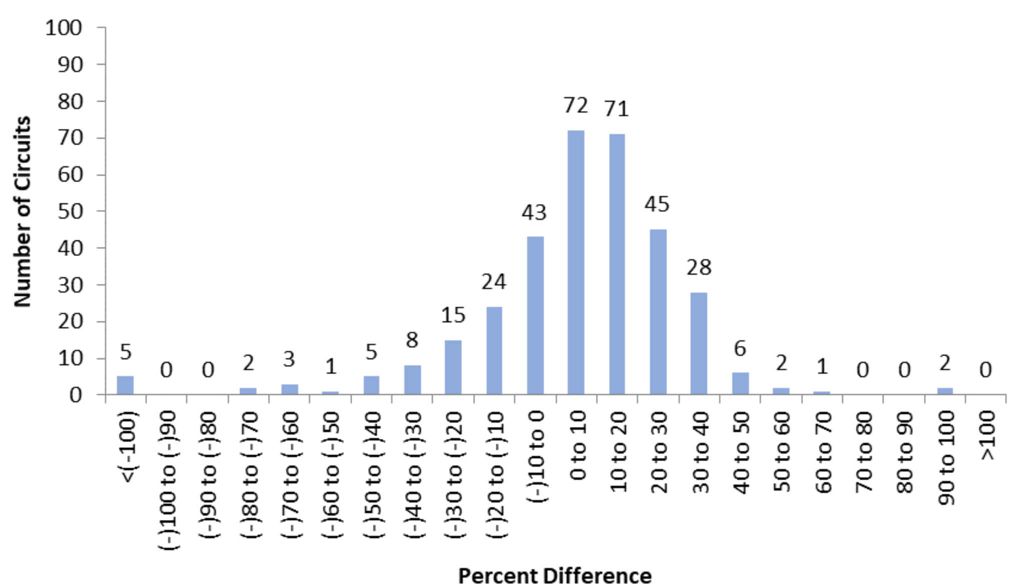


Figure 6-2: Histogram of Load Forecasting Error for First Year Forecast – SCE 2021-22 DIDF



Pacific Gas & Electric

A comparison of the actual and forecast load ((actual load-forecast load) expressed as a percentage of actual load) from the 2020-21 and 2021-22 DIDF cycles for PG&E are shown in Figures Figure 6-3 and Figure 6-4 respectively. In both cycles, as in the case of SCE, roughly 300 circuits were randomly chosen for this analysis.

Similar to the plots for SCE, the bars on the right side of the histogram plot show the number of circuits where the actual load is higher than the forecast load. Conversely, the bars on the left side of the plot show the number of occurrences where the actual load is lower than forecast. It can be seen that 85-90% of the forecast errors (282 out of 317 circuits in 2020-21 DIDF and 246 out of 291 circuits in 2021-22 DIDF cycles) have forecast errors in the range of -30% to +30%. It can also be seen that there is a slight bias to the left, i.e., there are more circuits with negative errors than positive errors. This means that the actual load is lower than the forecast more times than when it is higher than the forecast. Of the 317 circuits, 189 or approximately 60% of the circuits had negative errors in the 2020-21 DIDF cycle and of the 291 circuits, 219 circuits or approximately 75% of the circuits had negative errors in the 2021-22 DIDF cycle. As before, while the sample data size is sizeable (approximately 10% of circuits), it may not be sufficient to draw any conclusions on the inherent bias in the forecasting process.

Figure 6-3: Histogram of Load Forecasting Error for First Year Forecast – PG&E 2020-21 DIDF

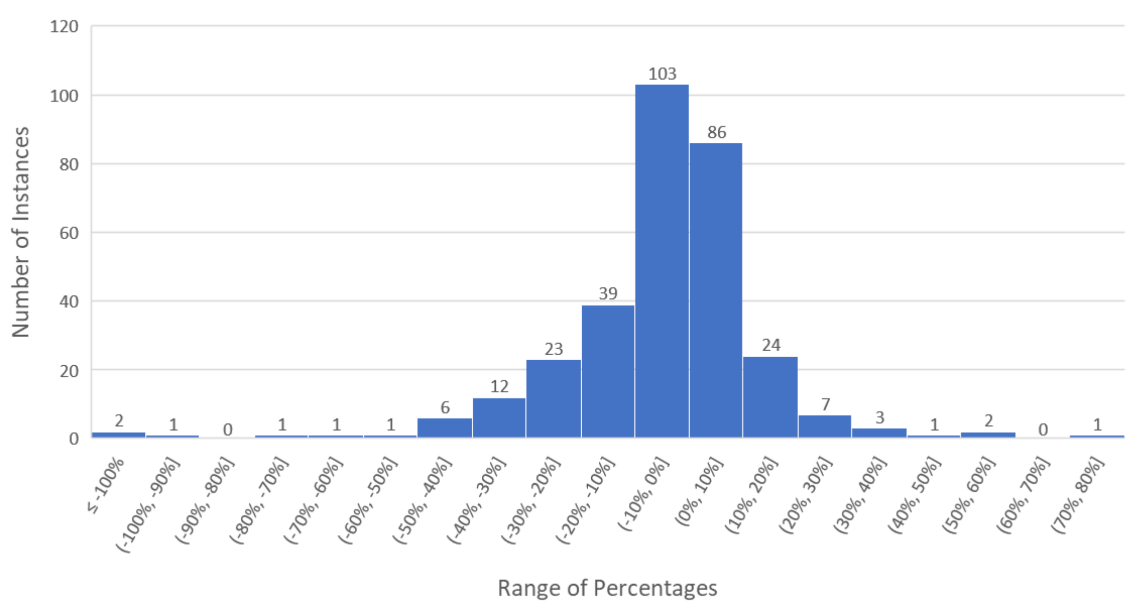
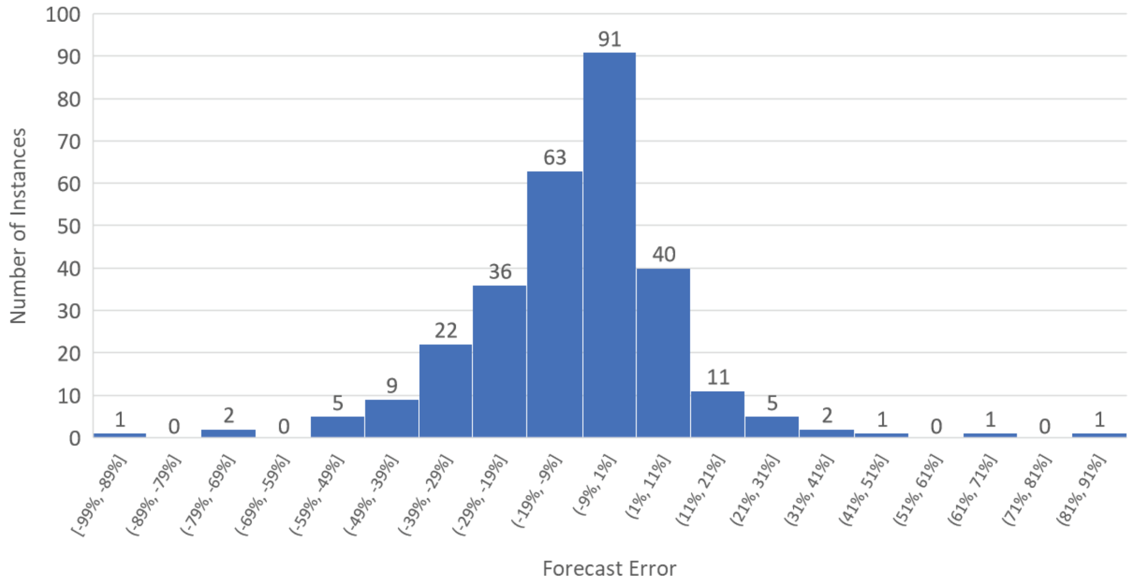


Figure 6-4: Histogram of Load Forecasting Error for First Year Forecast – PG&E 2021-22 DIDF



6.3. Observations, Conclusions, and Recommendations

- We observe that approximately 80% of sampled circuits for SCE and 85-90% of the sampled circuits for PG&E had forecasting errors that are within the range of -30% to +30%.
- We observe that there was a slight bias in the forecasting error for PG&E and SCE. In the case of SCE, the actual load was higher than the forecast for about 68% of the circuits sampled in the 2021-22 DIDF cycle. In the case of PG&E, the load forecast was higher than the actual load for about 75% of the circuits sampled for the same cycle. While the sample data size is sizeable (approximately 10% of circuits), it may not be sufficient to draw any conclusions as to whether there is any statistically significant bias in the forecasting process. Therefore, we recommend that the utilities review their forecast error data results to determine if there is something in their load forecasting processes that might be causing the bias in their forecasts and we recommend that the IPE review this area with the utilities in the upcoming cycle.

7. Electric Vehicle Known Load Growth Projects

7.1. Background

The known load tracking dataset discussed in Section 4 is meant to track the status of known load growth projects (known loads) over time from its initial use in the DPP until the known load is either 1) implemented (requested service is provided to the customer) or 2) the request for service is terminated by the customer. This dataset can then be used to perform some quantitative assessments regarding the known loads as discussed in Section 4. The IPE had discussions with all three IOUs to better understand specifically how known loads related to EV charging stations (electric vehicle known loads) are captured in the planning process and the possibility of these known loads changing in quantity and timing due to delays by the customer or the utility. The IPE gathered information from the IOUs in the areas listed below:

- Are there any corridors where the utility is seeing EV load growth now or expects significant growth in the future?
- How does the utility engage with the Electric Vehicle Service Providers (EVSPs) and EV fleet operators and whether the utility is aware of future projects prior to receipt of the customer's application?
- What triggers the creation of an electric vehicle known load project in the planning process?
- What programs and tools are available to support the interconnection and planning process?

7.2. Electric Vehicle Known Loads in three IOU's Distribution Planning Process

The responses provided by the three IOUs related to electric vehicle known loads are summarized below.

Southern California Edison

Electric Vehicle Load Growth Corridors

SCE is expecting EV load growth near the Port of Long Beach, along I-710 corridor, I-10 & I-15 intersections, and along the freeways to Las Vegas and Arizona. The expectation that these corridors will see high EV growth is based on historical pattern of requests as well as forward looking transport electrification (TE) potential studies conducted by the utility. The proactive identification of EV corridors using TE potential studies is something that SCE is continuously working on to enhance the current forecasting and planning process.

Engagement with EVSPs and Fleet Operators

SCE has a dedicated TE Project Management team to support EV customers. SCE also has dedicated personnel for their Charge Ready Program (https://www.sce.com/evbusiness/overview) that assists business and property owners with deploying the infrastructure and equipment necessary to support electric vehicle (EV) charging stations at the owner's locations.

SCE encourages EVSPs and fleet operators to provide information about their projects to SCE as early as possible. While SCE is able to gather high-level plans for future projects from some of its large EV customers, specific project-related information is typically known to them only when the customer applies for service, and no project submitted beyond 3 years. .

<u>EV Known Load Development Process</u>

SCE's customers have three options for determining if there is capacity to serve their desired load and to proceed to get service. The process for getting service can be found using the link below. https://www.sce.com/partners/consulting-services/localplanning

1. If a customer is interested in obtaining an estimate of capacity available on a circuit, they can do so by accessing maps that show the forecast loading of circuits as documented in SCE's GNA. These maps are provided in SCE's distribution resource plan external portal (https://drpep.sce.com/drpep/). Customers can proceed to options 2 or 3 below if they are interested in obtaining more information or applying for service The estimate obtained this way is non- binding and could be based upon year old data since the GNA is an annual process.

2. If the customer wants to know if there is sufficient capacity (with more precision) prior to submitting an application for service, they can have a detailed planning study performed by SCE for a fee. The study is focused on determining if there is sufficient distribution capacity available to provide the requested service. The results of study can point to one of three possible outcomes – (i) there is sufficient capacity available to provide the desired service, (ii) some capacity is available but not 100% of what is desired and how long it will take provide 100% of what is desired, or (iii) there is no capacity and how long it will take get the desired capacity.
   Whenever a customer provides several key pieces of information required for this study, the project is entered into the forecast as a known load by SCE. Key information includes customer name, address, service date, detailed demand schedule, site plan, etc.

3. If the customer wants to proceed to an application (and not use options 1 or 2), the customer must submit sufficient data (described below) for performing a capacity planning study. If a customer provides all documents for a complete design submittal, then no fee is required to perform the detailed engineering study. The three possible outcomes are similar to the outcomes of the results listed above for option 2. For the application (and full design study), the customer must submit AutoCAD drawings, property survey and signed copies of two SCE contractual documents (design and tariff - Rule 29/45 or Rule 15/16). Then a full design

study is performed that will calculate distribution capacity availability and performing any necessary design work.

EV Programs and Tools

SCE Distribution Resource Planning External Portal (DRPEP) (https://drpep.sce.com/drpep/) provides ICA and GNA layers that show the available capacity for uniform load on all the circuits. As mentioned before, customers can use the portal to get an estimate of the capacity available for their project. In addition, SCE offers the following programs, tools and workshops to educate EVSPs and fleet operators to support them on their projects.

- Quarterly industry group meetings to share information related to EVs by the eMobility team.
- Calculators and guides available on SCE's site
- Fleet workshop as a part of Power Service Availability Initiative
- Advisory services for customers that need help such as the EV Readiness Study
- Charge Ready program specific to customers that purchase and own vehicles.

Pacific Gas and Electric

Electric Vehicle Load Growth Corridors

PG&E indicated that it has received numerous and large applications along I-5 (San Francisco to Los Angeles) for Direct Current Fast Charging (DCFC) public charging. It has also received some applications to date along Highway 99 and anticipates Medium Duty/Heavy Duty (MD/HD) fleet charging load to develop based on volume of truck transportation of agricultural and manufacturing products originating within the San Joaquin Valley. PG&E also mentioned that I-80 (San Francisco to Lake Tahoe) is likely to see applications, and I-5 north of the Bay Area is likely to be a growth area, although possibly at a slower pace than I-5 San Francisco-Los Angeles segment.

Engagement with EVSPs and Fleet Operators

PG&E has teams that are dedicated to supporting EVSPs and fleet operators via both PG&E's EV customer programs and Service Planning & Design. The nature of the engagement with customers is based upon applications for service or program eligibility.

In addition to the standard New Business intake process, PG&E's Clean Energy Transportation (CET) team receives applications from customers who are looking for the support of its "turnkey" EV programs which include Level 2, DCFC and MDHD Fleets. The CET team supports the design and construction of both new service upgrades required and in some cases behind the meter "make ready" infrastructure. The DCFC program has a set of qualified EVSPs who are eligible to submit applications on behalf of customers through periodic site solicitations.

Recognizing the importance of collecting forecasting information earlier to better inform long lead-time capacity projects that can result in energization delays when conventionally planned based on applications received, PG&E is reaching out to large EVSPs and fleet owners to understand their longer-term electrification plans and better inform capacity planning.

PG&E is working on seeking feedback from customers that may not have specific sites or immediate applications to find out their long-term plans. PG&E also works with EV Service Providers (EVSPs) and fleet owners on their expansion outlook for existing sites, early investigation sites that are likely to materialized into requests for service. This work is being performed so that these third-party plans can ultimately be incorporated into long-term forecasting and planning.

Although general plans of developers are known, these developer plans are not always concrete and not for specific projects. Developers of large charging stations may know their future demand for charging infrastructure, but not have specific sites identified where chargers will be located. Major developers are aware of the challenges and are accustomed to the pre-assessment process.

EV Known Load Development Process

PG&E offers a "preliminary assessment" ("PA")to determine available capacity based on a customer's forecast load. An engineering advance is required before work begins, and a customer needs to provide supporting documentation. A checklist for the supporting documentation for the preliminary assessment can be found at www.pge.com/pge_global/common/pdfs/solar-and-vehicles/clean-vehicles/ev-fleet-program/EV-Customer-Application-Requirements.pdf. This website also provides details required to produce a PG&E Design (Estimate). The PA provides the following valuable information to assist an EVSP in continuing to develop a site:

i. Available capacity to serve the site
ii. Proposed location of utility equipment and approximate route to serve
iii. Required customer equipment

The PA is valid for 90 days upon issuance due to the dynamic nature of the electric distribution system. PG&E arrived at this timeline via benchmarking with other IOUs that perform similar preliminary evaluation services.

For forecasted loads that are >2MW, PG&E would typically perform a Large Load Study (LLS) due to the complexity of serving large loads, which would identify the most economically efficient method to serve the proposed load at a specific site. General timelines to deliver an LLS are 90-120 days and require an engineering advance before work begins. The service planning and design roadmap for EV customers can be found using the link below.

https://www.pge.com/pge_global/common/pdfs/solar-and-vehicles/your-options/clean-vehicles/charging-stations/ev-fleet-program/PGE-EV-Fleet-Customer-Roadmap.pdf

At the pre-assessment stage, the requested load service is added to bank and feeder load forecasts. If the application/planned load addition does not proceed to final design within 90 days of pre-assessment results, the new load will be removed from bank and feeder forecasts, allowing that capacity to be available for other potential new customers. Customer can opt to skip pre-assessment and instead move straight to final design. “Final design” can be considered as a milestone for maintaining the new load (“known load”) in the forecast. A larger engineering advance amount may be required if capacity work is required.

EV Programs and Tools

Currently, PG&E does not have a standalone informational program aimed at educating customers on the interconnection process. However, PG&E has developed educational resources, including customer journey maps that explain the process for seeking new service and/or adding to existing service through Service Planning or as part of their participation in an EV program. These reference materials include expected timelines, roles and responsibilities between the customers and PG&E, and an overview of the tools and systems involved.

San Diego Gas and Electric

Electric Vehicle Load Growth Corridors

SDG&E mentioned that a study performed by a coalition of 8 utilities in the west identified potential for mobile EV charging station development along the I-5 corridor. SDG&E expects to receive request for service from EVSPs this year in the I-5 and I-8 corridor driven by Federal grants. SDG&E also mentioned that new efforts (studies) are underway to forecast MD/HD EV loads in the future.

SDG&E pointed out that the cumulative system-level EV load growth forecasts in the DPP are limited to the cumulative CEC IEPR system-level forecast values for the 10-year forecast horizon. SDG&E indicated to the IPE that if it has good insight to future EV load growth projects, the use of this information would be limited to disaggregating the IEPR’s system-level load forecast to the circuit- and substation-level because of the requirement to adhere to the CEC IEPR forecast overall. The methodology used to disaggregate the IEPR’s electric transportation load components is described in SDG&E’s GNA report.

Engagement with EVSPs and Fleet Operators

SDG&E’s Clean Transportation team engages with fleet operators, school bus operators, transportation agencies and actively markets SDG&E’s programs. In addition, SDG&E’s Clean Transportation team conducts industry sponsored webinars, public events such as EV Fleet Day, as well as works with trade associations, chambers of commerce and advocacy groups to educate EV customers on fleet electrification and the EV-related programs that are available.

The New Business team typically assigns a single point of contact for large EVSPs. SDG&E mentioned that most of the work with EVSPs tends to be transactional. In a few cases, the customers may provide information on future projects, but this information is usually at a higher level (for example, number of projects for next year, city where they expect to install a charging station etc.).

EV Known Load Development Process

The service request process starts with the customer providing detailed information about load. The list of information that SDG&E needs to perform a load study is given in the link below.

https://www.sdge.com/sites/default/files/2022-08/BSP-Fact-Sheet-for-Documents-August-2022.pdf

SDG&E then engages with the customer and performs a load study. Once the planning engineer approves the load study, the load is added to the forecast that will be used in SDG&E's DPP, i.e., a "known load" is created and incorporated in the forecast.

An SDG&E Builder Guidebook explains the load study will be submitted in phase 2 after the customer has paid an engineering fee and submitted all documents required to begin a preliminary design.

https://www.sdge.com/sites/default/files/documents/SDG%26E%20Builder%20Guidebook%20v11.4.pdf

For customers that participate in an EV program, the programs group does the design and engineering, and submits a request for a load study only after the customer signs an agreement to participate in the program and obtains necessary easements for the project.

EV Programs and Tools

SDG&E's website contains program FAQs, timelines, online tools, grant information, etc. which is available for program participants. A link to EV programs is provided below.

https://www.sdge.com/business/electric-vehicles/lovelectric

Program participants don't have much visibility into the interconnection process and don't need it since the clean transportation group does the upfront work including moving the EV load addition request through the interconnection process.

There are resources on SDGE's website to guide new business customers through the application and interconnection process as discussed above. SDG&E also provides ICA maps that can be used to get an estimate of available capacity on specific circuits.

https://www.sdge.com/more-information/customer-generation/enhanced-integration-capacity-analysis-ica

7.3. Observations, Conclusions and Recommendations

- Utilities are gaining good insight into corridors where EVs are likely to request service based upon interaction with developers and analytical studies. This information on where potential EV load growth could occur is used for disaggregating the CEC IEPR EV load forecasts in the annual distribution planning process. As discussed in more detail in Section 2, some of this additional insight is not fully incorporated in the current DIDF/DPP processes since the forecasts used in the DPP process are capped by the IEPR forecast. As a result, we recommended in Section 2 including some scenario planning in the DIDF to consider the need to construct long lead time infrastructure.
- Most utilities have a new business team that handles service requests from all customers including EV customers. Within the new business team, most utilities appear to have a team that focusses on EV customers or assigns a single point-of-contact to large EV customers. In addition, all the utilities appear to have dedicated teams that run EV-related programs.
- All three IOUs engage closely with EVSPs and fleet operators. All three utilities have programs to install make-ready charging infrastructure for medium- and heavy-duty electric vehicles, working with fleets from the initial infrastructure planning stage through to design, construction, and ongoing site maintenance. The utilities offer workshops and industry group meetings to share information related to EVs obtaining service. The utilities also reach out to large EV charging developers and fleet owners to understand their longer-term electrification plans and better inform the utility's capacity planning.
  Although the general plans of developers are often known, these plans are not always concrete and not specific enough to use in the DPP process as a known load for example. Developers of large charging stations may know their future requirements for charging infrastructure, but not have specific sites identified where chargers will be located.
- All three utilities have a streamlined process for service requests. Some utilities also offer a pre-assessment study for EV customers. The utilities only include a service request as a known load project when the customer has met certain milestones such as submitting an application. The utilities also prevent customers from easily "locking up" capacity by charging a fee, although small, for the pre-assessment and by requiring an application or supporting information be provided within a pre-defined time period (for example within 90 days) or lose one's place in the capacity queue.
- Utilities provide ICA maps and may offer pre-assessment studies. Most EVSPs seem to be very familiar with the interconnection process at this point.

8. Resiliency Needs in the GNA

8.1. Background

CPUC Decision D.16-12-036 issued on December 22, 2016 defined the services to be procured from DERs through the competitive solicitation framework to defer distribution infrastructure. The services included "distribution capacity, voltage support, reliability (back-tie) and resiliency (microgrid)". Decision D.16-12-036 also provided definitions of these services provided by DERs.

Thus far, only PG&E has identified planned investments for deferral by DERs using the resiliency service in past DIDFs. SCE and SDG&E have not identified any needs for resiliency service. In its August 15, 2022 GNA report, SDG&E recommended that the Commission modify Decision 16-12-036 to eliminate "resiliency (microgrids)" as a planned investment that is deferable by DERs.

In this section, the IPE will review the approach taken by the three IOUs regarding the resiliency (microgrid) service under the DIDF.

8.2. Resiliency Service Provided by DERs

The competitive solicitation framework working group final report dated August 1, 2016 referenced in Decision D.16-12-036 provides the following definition for Resiliency Service.

> "Resiliency (Microgrid) services are defined as load modifying or supply service capable of improving local distribution reliability and/or resiliency. Specifically, this service provides a fast reconnection and availability of excess reserves to reduce demand when restoring customers during abnormal configurations. <u>In addition, this service will also provide power to islanded end use customers when central power is not supplied and reduce duration of outages.</u> These resiliency services can be provided by a single DER resource and/or an aggregated set of DER resources that are able to reduce the net loading on specific distribution infrastructure coincident with the identified operational need in response to a control signal from the utility. In a microgrid application it is necessary for a system to match generation to load while maintaining voltage, frequency, power factor and power quality within appropriate limits. This requires an isochronous supply resource."
>
> "Examples of traditional "Wires" equipment that currently support providing this type of service include, but are not limited to are, circuit breakers and relays, reclosers and recloser controllers, switches, sectionalizers, fault interrupters, SCADA, FLISR, and Distributed Energy Resource Management Systems (DERMS)."

The key difference between the resiliency service (microgrid) and the reliability service (back-tie) is that the resiliency service requires the DERs to operate in islanded mode.

8.3. Needs Identified for Resiliency Service by the three IOUs

Southern California Edison

SCE mentioned that it typically does not identify any resiliency needs as a part of the annual DPP process. SCE also did not propose any specific resiliency projects as a part of the CPUC microgrid proceeding[9]. SCE has not identified any needs for resiliency services in any of the previous DIDF cycles.

Pacific Gas & Electric

PG&E has designated two types of projects for resiliency (microgrid) services by DERs in past DIDF cycles.

- One of PG&E's planning criteria requires limiting the total number of customers served on a feeder to 6,000 customers. The reason is that these feeders serve a large number of customers which poses two issues: (1) a large number of customers are affected when an outage occurs; (2) typical loading on adjacent circuits could limit the ability to reconfigure the system in a manner to serve some or all of these customers during an outage. These issues negatively affect both customer outage frequency and duration. The planned investment in the DDOR report that is proposed to address these needs is adding a new distribution circuit and splitting the customers more or less evenly on the two circuits (new and existing). PG&E has identified these projects for deferral by resiliency (microgrid) service by DERs in the last two cycles (2021 and 2022). In years prior, these needs were categorized as reliability needs. PG&E justified this change by stating "In order for a DER solution to provide a reliability benefit in the same manner as reducing customer count on a circuit, a set of customers on the circuit would need to be immediately served by other means during an outage. This can be accomplished by forming an island that includes a part of the circuit so that those customers are not affected by the outage."
- PG&E also designates emergency bank loss projects as resiliency projects. According to PG&E they are resiliency projects since to defer the planned investment (typically addition of transformation capacity) would require DERs to operate as a microgrid to serve customers who would have otherwise been served by the new transformer. For example, PG&E identified the Pueblo Bank 1 project for deferral by resiliency (microgrid) service in the 2022 DIDF. This project addresses an overload on Pueblo Bank 1 as well as an existing Pueblo Substation emergency bank loss deficiency. In the advent of a loss of Pueblo bank 1, after all

[9] A Ruling under Track 4 of the Microgrids proceeding (R.19-09-009) issued on August 23, 2021 directed parties to submit microgrid and resiliency proposals to address Governor Gavin Newsom's July 30, 2021 Proclamation of a State of Emergency.

available transfers have been exhausted, there would remain load unserved for 24-48 hours, until a mobile transformer could be deployed and placed in service. PG&E has classified the Pueblo Bank 1 need as a resiliency (microgrid) need because the DER solution would require a microgrid to provide service until the mobile transformer is interconnected. In this case it appears that a solution is a microgrid and that microgrid could operate interconnected to PG&E's distribution system.

It appears that PG&E identified the planned projects for the above two mentioned types of needs for resiliency service because they believe the DER solution would be required to operate in islanded mode to be comparable with the wired solution as discussed above.

San Diego Gas & Electric

SDG&E indicated that it does not identify any resiliency needs as a part of the annual DPP process. However, as part of the Microgrid OIR, SDG&E received Commission approval for four utility-owned circuit-level energy storage microgrid projects in order to provide local grid reliability and to help address overall system generation shortfalls, as well as islanding and resiliency capabilities pursuant to Decision (D).21-12-004 issued on December 2, 2021.

SDG&E included these four multi-premise microgrid projects in its 2022 GNA and DDOR report as required by the ALJ's May 11, 2020 ruling which states "In the DDOR list of planned investments, the IOUs shall identify all DER solutions planned for IOU ownership or otherwise planned for procurement but not prioritized as deferral opportunities." In the DDOR report, SDG&E stated that while third party DERs can be included and used within the microgrid, the utilities have an obligation to serve and to operate their facilities safely and reliably. Therefore SDG&E will own and operate the equipment necessary to (i) isolate/reconnect the microgrid from/to the remainder of the system, and (ii) control frequency and voltages within the microgrid boundary during island mode. SDG&E stated that for this reason they believe it no longer makes sense to consider "resiliency" as a service that third party DERs can provide to defer utility investments that are necessary to form and operate a multi-customer/premises microgrid. SDG&E therefore recommended that the Commission modify Decision 16-12-036 to remove "resiliency (microgrid)" as a service that can be provided by DERs to defer investments that a utility is planning in order to provide resiliency.

8.4. Observations, Conclusions, and Recommendations

- All three IOUs don't seem to identify resiliency projects as a part of their annual distribution planning process. Here, resiliency projects refer to projects that enable the distribution system to anticipate, survive, sustain, recover from, and adapt to high impact low frequency events.
- PG&E is the only utility to identify planned projects for deferral by resiliency service. PG&E has considered two types of planned projects for resiliency service related to: 1) their planning criteria that requires limiting the total number of customers served on a feeder to 6,000 customers and 2) avoiding extended customer outages due to an emergency bank loss. Both of these projects are proposed for resiliency service because this service requires the DERs to

be able to operate in an islanded mode which is required for the DER solution to be comparable with the wired solution.

- SDG&E has received Commission approval for four utility-owned circuit-level energy storage microgrid projects to solve reliability and resiliency needs as a part of the Microgrid OIR. SDG&E stated that while third party DERs can be included and used within the microgrid, it would need to operate the equipment necessary to isolate/reconnect the microgrid and control frequency and voltages for safety and reliability reasons. SDG&E further stated that for this reason they believe it no longer makes sense to consider "resiliency" as a service that third party DERs can provide to defer utility investments that are necessary to form and operate a multi-customer/premises microgrid.
- The IPE is of the opinion that the resiliency service (microgrid) should be retained in the DIDF since PG&E has identified planned projects for deferral using this service in the past few DIDF cycles and may do so in the future.
- We note that the Energy Division has encouraged the IOUs to propose utility owned DERs. We assume that would also include microgrids including utility-controlled multi-premise microgrids that use utility distribution facilities. The IPE recommends that a CPUC policy needs to be developed regarding whether a multi-premise microgrid project that is not a pilot project, or a project approved in another proceeding should be considered for resiliency service by DERs. The policy also needs to address which specific types of microgrids (substation-level/multi-premise, renewable generation-based/fossil generation-based etc.), if any, should be considered for resiliency service by DERs in the DIDF.

Appendix A SCE Known Load Tracking Data

Listed below is information describing the data elements included in SCE's Known Load Tracking Data.

1. **Circuit Name:** Normal name used for the circuit that the known load will be served on.
2. **Unique identifier**:
    1) Unique Identifier is a source key in SCE's database. It is assigned automatically when a new known load is added. The numbers sequence such that the larger numbers are more recent entries.
    2) Typically, a load growth project would have one unique identifier even if the load is on multiple feeders and grows over time. However, according to SCE very large LGPs may need to be broken up to provide sufficiently granular data. Example of such a known load is a mega tract home construction with 21,000 homes - 1 identifier for 5 circuits - broke it up in the data submitted this year by project phases. SCE indicated that it may go back and breakup and assign additional unique identifiers for older large known loads in its data submittal in the next cycle.
    3) 300 KVA is the cutoff for including known loads (SCE calls them Load Growth Projects or LGP) in the forecast (smaller projects are not considered for known load accounting treatment).
3. **Sector**: Customer class – Agriculture, Commercial, Residential, Industrial
4. **Category:** Based on types of customers. For example, cultivation, Ag Water Pump, Industrial Plant or Mega Tract Homes. SCE has 32 categories and others may be added. Categories used in the tracking data submitted by SCE this year are listed below.
    1) Agricultural Water Pump
    2) Agriculture / Food Processing
    3) Apartments
    4) Business Park (Office Buildings)
    5) Commercial Water Pump
    6) Cultivation
    7) Custom Homes
    8) Data Centers
    9) Distribution/Fulfillment Centers
    10) Industrial Plant

11) Load WDAT
12) Lodging
13) Low Duty Commercial EV Charger
14) Medical
15) Medium / Heavy Duty Commercial EV Charger
16) Mega Tract Homes
17) Metro and Train Lines
18) Mixed Use
19) Other
20) Refineries
21) Reservation-related
22) Schools (including universities and colleges)
23) Shopping Centers
24) Speculative Building
25) Sports Facilities
26) Temporary Power
27) Tract Homes
28) Zero Net Energy (ZNE)

5. **Requested load amount:**

    1) Based on equipment and load schedule provided by the customer (if a load schedule is provided)

    2) Some customers may provide a single value (example, IEEE standard panel rating) and others may provide a detailed load schedule

    3) Discount factor (DF) of 75% (standard) is applied to the requested load to capture the customer's expected peak load consumption compared to its requested load amount (sometimes referred to as "load diversification"). If the customer provides a detailed load schedule, then the DF may be set at 1 for that customers request.

    4) The value provided for a known load in the data submitted with their DDOR is the sum of the MVA values for the five-year planning period. The IPE notes that the other IOUs were providing annual values and interpreted the ruling as requesting annual values similar to ones analyzed in the DDOR prior to the ruling. The IPE has since confirmed that the other IOUs are providing information on an annual basis.

6. **Initial service request date**: the date customer's service request was entered into MDI

7. **Current expected in-service date**:

1) For multi-year project, the first year the load is expected to materialize (example - 2023 is entered into the SCE data base if the known load has 1 MW increase in 2023 and another 0.5 MW in 2024. The SCE data base automatically populates a specific (example 12/31/2023) using the earliest year of the known load (2023).

2) Items marked as N/A is equivalent to a year of 2022 for this cycle.

8. **Status:**

1) Cancelled, ongoing or completed

2) SCE plans to retain the completed and canceled projects in the following year's report and remove in the subsequent year.

9. **Actual service date**:

1) This is the year in which service is provided. SCE mentioned that it's getting complicated to track this for mega tract projects that have separate meters for each phase. This may have to be revisited in the future.

10. **Actual load amount**:

1) The IPE clarified that this is not the meter read, but an entry is made if the customer requested amount is changed from the previously requested amount of service by the customer in the year service is provided (service actually commences).

Appendix B PG&E Known Load Tracking Data

Listed below is information describing the data elements included in PG&E's Known Load Tracking Data.

1. **Circuit:** Name of the Feeder that the unique load adjustment is applied to. Note that the same feeder exclusion list used in the GNA applies to the known load adjustment list.
2. **Unique Identifier:** Unique identifier for individual load adjustments. A single customer application for service may result in more than one load adjustment, depending on whether multiple types of load are applied for and whether the load will increase across multiple years.
3. **Sector:** New Residential, New Industrial, New Agricultural, New Commercial, New Cannabis, and EV are the available categories.
4. **Category:** PG&E does not currently break the sectors down into finer categories.
5. **Load Amount (MVA):** Engineering-approved load amount for each unique adjustment. This amount is usually based on customer usage for other, similar customers and does not necessarily represent the load amount provided by the customer on their application for service.
6. **Initial Service Request Date:** Data not currently available. PG&E is developing tools to track this data for future DIDF Cycles.
7. **Current Expected In-Service Date:** Forecast year in which the adjustment is expected to come online.
8. **Status:** Data not currently available. PG&E is developing tools to track this data for future DIDF Cycles.
9. **Actual In-Service:** Data not currently available. No adjustments in the 2022 GNA were in-service when the 2022 GNA forecasts were created. PG&E is developing tools to track this data for future DIDF Cycles.
10. **Actual Load Amount:** Data not currently available. No adjustments in the 2022 GNA were in-service when the 2022 GNA forecasts were created. PG&E is developing tools to track this data for future DIDF Cycles.

Appendix C SDG&E Known Load Tracking Data

1. **Unique Identifier**: An identifier associated with each load adjustment. If a service request is for a load that increases over time (for example, tract home construction in phases (1MW in year 1, 5 MW in Year2, 3.3 MW in year 3 etc.), there will be a unique identifier for each incremental change in load.
2. **Initial Service Request Date**: SDG&E's interpretation from the ruling is that this is the "date customer made the request" and not the in-service date initially requested by the customer. The in-service date initially requested by the customer was not provided by SDG&E in the 2022 cycle. SDG&E mentioned that it will consider the in-service date initially requested by the customer in the next cycle based on SDG&E's interpretation of the ALJ ruling.
3. **Current in-service date**: This is the most up to date in-service date requested by the customer updated at the time of the report, it could be the same as the original in-service date requested.
4. **Load amount**: This is the load amount (MW) **at the time of the feeder peak** estimated by SDG&E based on working with the customer.
5. **Customer type/category**: SDG&E provided customer category (residential, commercial etc.) based on SDG&E's interpretation of the ruling.
6. **Actual in-service date**: This is the date the load is placed in customer is energized. SDGE already provided an explanation in the GNA-DDOR report on why the actual in-service date was earlier than current in-service date in many cases.
7. **Actual load amount**: This data was not provided. SDG&E interprets that the actual load amount represents the actual capacity that SDG&E provided to the customer at the time they are energized. SDG&E stated that this value will always match the load amount identified in #4.
8. **Status**: SDG&E provided this information in the in-service column sine the Ruling asked for "current expected in-service date or indication if service request was cancelled".

2022 Independent Professional Engineer

Post DPAG Report

Public Version

Submitted to Energy Division, PG&E, SCE, and SDG&E

Date: March 17, 2022

Resource Innovations

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Half Moon Bay, CA 94019

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Statement of Confidentiality

The CPUC made provision for the Investor-Owned Utilities to request confidentiality treatment for certain data submitted in their GNA/DDOR reports or other material provided to the IPE that is contained in this report. The utilities have indicated that no data in this report is confidential. Thus, this PUBLIC VERSION of the report can be distributed to any interested party.

Contents

1. Introduction and Background

Summary of CPUC April 13, 2020 and May 7, 2020 Rulemaking

The paragraphs that follow summarize the parts of the April 13, 2020 CPUC Ruling (14-08-013) that directly impact the role of the IPE and/or this report.

The Ruling modified the Distribution Investment Deferral Framework (DIDF) process and filings with respect to the Independent Professional Engineer (IPE) scope of work and provided the updated 2020-2021 DIDF cycle schedule. Attachments A and B of the Ruling include a listing of the IPE-specific reforms discussed in the Ruling and the updated IPE scope of work. These Attachments of the Ruling are attached as Appendix A of this report.

In Decision 18-02-004, the Commission adopted the DIDF. Building upon the Competitive Solicitation Framework developed in the companion Integration of Distributed Energy Resources proceeding, the DIDF established an ongoing annual process to identify, review, and select opportunities for third party-owned distributed energy resources (DERs) to defer or avoid traditional capital investments by the investor-owned utilities (IOUs) on their electric distribution systems. Decision 18-02-004 ordered the IOUs to implement the DIDF as an annual planning cycle that would potentially result in the selection of distribution upgrades for deferral through the competitive solicitation of DERs.

The DIDF was implemented in 2018 and 2019 with the expectation that it would be evaluated and revised after each cycle to improve the process. To that end, the assigned Administrative Law Judge (ALJ) issued a Ruling Requesting Answers to Questions to Improve the Distribution Investment Deferral Framework Process on February 25, 2019 (February 25, 2019 Ruling). Based on comments received in response to the questions, the ALJ issued a Ruling Modifying the Distribution Investment Deferral Framework Process on May 7, 2019 (May 7, 2019 Ruling). Stakeholders proposed additional recommendations for DIDF reform throughout the 2019 DIDF cycle. A Ruling Requesting Comments on Possible Improvements to the 2020 Distribution Investment Deferral Framework Process was subsequently issued on November 8, 2019 (November 8, 2019 Ruling), and the contents of this Ruling further modify the DIDF. A Ruling on May 11. 2020 modified the DIDF filing and process requirements including proposing a number of possible reforms to the DIDF.

The CPUC issued Decision 21-02-006 on February 12, 2021 titled Decision Adopting Pilots to Test Two Frameworks for Procuring Distributed Energy Resources that Avoid or Defer Utility Capital Investments. In that ruling the CPUC added two additional procurement mechanisms to the DIDF cycle and spelled out how pilots of these two mechanisms are to be implemented over the next few DIDF cycles. The two new mechanisms are called the Standard Offer Contract (SOC) pilot, which applies to in front of the meter (IFOM) DERs, and the Partnership Pilot (PP), which applies to behind the meter (BTM) DERs. The ruling also includes some revisions to the DIDF process and timing which are followed in this cycle's IPE review and in this report.

This decision requires IOUs to recommend at least one Tier 1 and two Tier 2/3 projects for the Partnership Pilot, which is only open to behind-the-meter (BTM) DER technologies. In addition, IOUs are required to recommend at least one Tier 1 project for the SOC pilot, which is only open to in-front-of-the-meter (IFOM) DER technologies. The IPE scope of work outlined in Appendix A provides for improvement to the IPE review process based on comments received and clarifies that IPE's work for each IOU will be overseen and approved by Energy Division. According to the Ruling, it is important that the IPE has sufficient time to prepare the IPE Plans in advance of the GNA/DDOR filings and that after the filings, the IPE has the cooperation and coordination of the IOUs necessary to collect the data needed for review in time to prepare the IPE Preliminary Analysis of GNA/DDOR Data Adequacy and IPE DPAG Report.

The revised IPE scope reflected in Ruling 14-08-013 includes the requirement to develop an IPE Plan that will cover most if not all of the IPE activities.

According to the Ruling, planning standards that lead to the identification of reliability needs need not be reviewed during this cycle. Instead, the IOUs should provide the IPE with planning documentation that supports the identification of all reliability needs. At this time, a formal review of IOU planning standards is not required as it could be a significant undertaking. However, the Ruling states that the Energy Division should discuss the GNA/DDOR filings with the IPE to determine if inconsistencies and shortcomings in the IOU planning standards exist and whether further review should be prioritized for future DIDF cycles.

The Ruling goes on to state that to further assist the IPE with DPAG Report completion, a new IPE Post-DPAG Report deliverable is included within the IPE scope of work. The IPE Post-DPAG Report should review and compare overall IOU DIDF compliance and make recommendations for process improvements and DIDF reform.

As stated in the May 7, 2019 Ruling, the IPE shall report directly to the Energy Division while preparing its deliverables and conducting its analyses for DIDF implementation. The April 13, 2020 Ruling states the term of the IPE scope of work shall be the entire DIDF cycle, which starts on January 1 each year to plan for Pre-DPAG and DPAG implementation and concludes on July 31 the following year after all RFOs are concluded and all DIDF reforms are implemented. As a result, IPE scopes of work for each DIDF cycle will overlap.

The schedule and milestones established by the April 13, 2020 Ruling and since updated are shown below.

Table 1-1: DPAG Schedule for 2021-2022 DIDF Cycle

Activity	Date
Pre-DPAG 2021	
Pre-DPAG meetings and workshops, including Draft IPE Plans review	May 2021
DPAG 2021	
IOU GNA/DDOR filings, Final IPE Plans circulated	August 16, 2021
IOUs update DRP Data Portals with GNA/DDOR data	August 30, 2021
IPE Preliminary Analysis of GNA/DDOR data adequacy circulated	September 5, 2021
DPAG meetings with each IOU	September 15, 2021 (week of)
Participants provide questions and comments to IOUs and IPE	September 25, 2021
IOU responses to questions	October 5, 2021
Follow-up IOU meetings via webinar	October 18, 2021 (week of)
IPE DPAG Reports	November 15, 2021
DIDF Advice Letters submitted (Tier 2 Advice Letter to not launch RFOs for any additional deferral opportunities Tier 2 Advice Letter to launch Partnership Pilot	November 15, 2021
Post-DPAG 2021 and 2022	
Launch RFOs for DERs	September 15, 2021 for Tier 1 candidates January 15, 2022 for Tier 2/3 candidates identified after September 15
IPE Post DPAG Report	March 15, 2022 (revised by Energy Division)

Independent Professional Engineer

The California Public Utilities Commission (Commission) rulings direct Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities or IOUs) to enter into a contract with an Independent Professional Engineer (IPE). The role of the IPE is as previously described.

Through a contract with Nexant, Inc. (now Resource Innovations), the three utilities separately engaged Mr. Barney Speckman[1], PE, to serve as their advisory engineer (referred to as the Independent Professional Engineer (IPE)) for the scope described in the April 13, 2020 CPUC Ruling.

1.1. IPE Plan

As required by the April 13, 2020 Ruling, the IPE developed an IPE Plan that served to guide the IPE's steps to implement its 2021 DIDF cycle work scope. The plan was developed using a three-step process:

1. In step 1 the IPE developed a draft IPE Plan working with the Energy Division and each utility by mid-May 2021.
2. The Plan was distributed to the service list and also discussed at the CPUC Distribution Forecasting Working Group meeting - both in an attempt to obtain stakeholder feedback on the plan.
3. Based upon stakeholder feedback received and under the direction of the Energy Division, the IPE revised the plan and made its IPE Final Plan available on August 15, 2021.

A copy of the Final IPE Plan was included in the three DPAG Reports completed by the IPE which were included in the utilities' Advice Letters.

The IPE Plan covers the business processes that the IOUs use to identify which distribution and/or subtransmission projects are recommended to proceed to an RFO (or the SOC or PP) seeking DER offers to determine if there is a cost-effective non-wires alternative. One of the core purposes of the plan is answer the question – Are the IOUs identifying every project that could feasibly and cost effectively be deferred by DERs?

The business processes in the Plan are organized generally in the order that they are performed. Starting with capturing the peak load values for each circuit for 2021, using the CEC IEPR forecasts to develop utility specific system level values which are then disaggregated to the circuit level

[1] Consistent with the CPUC decision, the contract with Resource Innovations, the firm where Mr. Speckman is employed, provides for other individuals within the organization to assist Mr. Speckman to perform the work in the IPE contract provided that these other individuals are also bound by the same confidentiality and conflict of interest requirements that Mr. Speckman is required to meet.

adjusted for known loads and then used to determine if there is an overload or any other issue during the planning period. For circuits that have a need, a planned investment is selected, capital costs developed for that project, and the planned investments are screened to develop a list of candidate deferral projects. These candidate deferral projects are then prioritized into tiers using several metrics and then considered for solicitation through an RFO, or through the SOC pilot or Partnership pilot.

This report covers a number of follow up items as well as several Steps in the IPE plans that were not completed prior to the development of the IPE DPAG Reports – namely Steps 21 and 23. These steps are identical in the three utility IPE plans and are summarized below for the reader's convenience.

Table 1-2: Steps of the IPE Plan Addressed

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle
21	Review list of internally approved capital projects	Review areas described as warranting further discussion with the IOUs in the 2021 IPE Post DPAG Report.
23	Track solicitation results to inform next cycle	Part of IPE Post-DPAG Report in coordination with the IE. (Note, since the utilities are submitting a report every six months per Reform # 41, there is no further discussion of this Step in the remainder of the report.

1.2. Definitions of Verification and Validation

As part of the development and implementation of the IPE Plan, detailed definitions were developed to clarify the meaning of Verification and Validation as applied to the IPE scope of work. These definitions which are used and applied in all IPE deliverables, are listed below:

Verification – Is a review performed by the IPE during which an independent check is performed to determine if the results produced were developed using data assumptions and business processes that were defined and described by the utility or are based upon standard industry approaches that do not have to be defined and described. In other words, "Did the IOU follow their own processes correctly as defined by the IOU?"

Validation – Is a review performed by the IPE during which an independent assessment is performed of the appropriateness of the approach taken by the utility to perform a task from an engineering, economics and business perspective. In other words, “Are the processes implemented by the IOU the best way to identify all planned investments that could feasibly be deferred by DERs cost effectively? And to what extent were the IOU methodologies appropriate and effective?”

1.3. Approach to Data Collection

The information reflected in this report was obtained through a number of methods including:

- The GNA and DDOR Reports and associated data reviewed were the confidential version of those documents that were filed in August 2021.
- The data that was used to complete Step 21 was provided by the utilities in response to IPE data requests in 2022.
- The remainder of the information used to complete this report was data provided in response to IPE requests for information in 2021 and 2022.

1.4. Report Contents

The remainder of this report includes the following sections:

- Section 2 – Comparison of Utility GNA/DDOR Reports and Accompanying Data
- Section 3 – Load Forecasting – Known Project Load Growth
- Section 4 – Candidate Deferral Project Prioritization Methodology including Forecast Certainty and Use of Flags and Operational Requirements
- Section 5 – Capital Project Review
- Section 6 – Selection of SOC and PP Pilots
- Section 7 – Miscellaneous Review Results including Back-tie planning
- Section 8 – DIDF Reform Items
- Appendix A – CPUC Ruling Excerpts of IPE Scope

2. Comparison of Utility GNA/DDOR Reports and Accompanying Data

This section includes a high-level comparison of the GNA and DDOR Reports and accompanying data filed by the three utilities in the 2021/2022 DIDF cycle. It includes a table comparing the three filings which also includes reference as appropriate to the fifty-six DIDF cycle related reforms that were included in the CPUC's May 7, 2020 Ruling. Following this comparison table is a second table that lists the full text of all fifty-six reforms for easy reference. This second table also includes an indication of whether this reform is "Included in this report" or "Not included in this report" or is an item that will be addressed in the "Future".

2.1. Comparison of Utility GNA and DDOR Reports

Table 2-1 includes a comparison of the GNA and DDOR filings of the three utilities. The table lists an aspect of the filing or one of the requested reforms in the first column, then it lists whether the utility included such material in its filing (e.g., Yes or No) and in some cases provides details on the utilities' response. The order of the rows included in the table generally follow the order of the business processes or content covered in the GNA and DDOR Reports.

Table 2-1: Comparison of GNA and DDOR Reports

Item	Description	PG&E	SCE	SDG&E
1	Includes a list and brief description of process changes since last GNA Report	Yes, PG&E filed segment level results after the GNA/DDOR filing date with CPUC approval of the revised date.	N/A. There were no major changes between 2020 and 2021 DIDF.	There are no changes in data formats between SDG&E's 2021 GNA and SDG&E's 2020 GNA.
2	Includes an Executive Summary of GNA/DDOR and results	Yes	Yes	Yes
3	IOU to provide indication of the accuracy of their planned investment cost estimates using the AACE expected range of accuracy classification system. Part of Reform #33	Yes, all projects are identified as AACE classification Class 5.	Yes, AACE classification provided for all planned investments (including candidate deferral projects).	Yes, all projects are identified as indicative of AACE classification Class 5.
4	The same IEPR datasets shall be used by all three IOUs in the preparation of their GNA/DDORs. The IOUs shall meet and confer to establish which IEPR datasets are used for forecasting and dis-aggregation and present a listing of	Yes, data sets approved by ED.	Yes, data sets approved by ED. Used 2019 IEPR Mid case for all DERs except EE which used Low.	Yes, data sets approved by ED. Used 2019 IEPR Mid-Mid case for all DERs except EE which used Mid-Low.

	the selected datasets to Energy Division for approval. Reform #3			
5	The IOUs shall also discuss the requirements that would enable forecasts of circuit segment and voltage and/or reactive power needs beyond three years. Reform #16	Yes, Per PG&E, completed in 2020 and does not have to be repeated.	N/A, Reform #16 was addressed in 2020 Narrative Sections 3.5 and 3.7.	Yes, SDG&E contends that there is no benefit in forecasting these needs beyond year 3 of the planning horizon given (i) the high level of uncertainty of these needs, and (ii) that if such needs were in fact to arise, they can be addressed with projects having relatively short lead times.
6	Utilities should consider IOU Ownership Reform #45	Yes, PG&E encourages bids for all forms of resource ownership (e.g., utility-owned, third-party owned, customer-owned, joint ownership) in their DIDF RFOs, allowing for bid participation and evaluation without any bias towards a specific ownership model.	Yes, SCE intends to evaluate it as methods, software, processes are further developed.	Yes, in the 2020 GNA/DDOR report, SDG&E stated that they were not aware of any issues related to IOU ownership, cost recovery, and procurement of DERs. This is in compliance with the Attachment B of the May 11, 2020 Ruling which states this recommendation is to be included within the 2020 GNA/DDOR filings.
7	Value stacking within Joint Prioritization Workbook Template. Reform #28	PG&E only solicited for the deferral service and each deferral opportunity provided an opportunity for the DER developer to value stack other revenue streams and reflect that it their bid price.	N/A, Reform #28 was addressed in 2020 Narrative Section 3.8.	Yes, SDG&E indicated support for value-stacking through existing processes where DER providers can monetize the resource's various value streams.
8	Results of Day-Ahead Dispatch and SCE's Local Resource Constrained	N/A	No, Reform 47 was addressed in 2020	N/A

	Day (LRCD) Provision of Pro Forma Contract Reform #47 (SCE Only)		Narrative Section 3.9	
9	Provides Summary of Distribution Planning Process with some detail description	Yes	Yes	Yes
10	Includes description of historical peak data capture, normalizing and adjusting to extreme weather conditions	Yes	Yes	Yes
11	Includes description of process used to develop year net load forecasts	Yes, for 10 years.	Yes, for 10 years.	Yes
12	Includes description of load disaggregation description	Yes	Yes	Yes
13	Identifies Electric System Needs (for 10-year horizon for Pre- and Post-Application Projects)	Yes, however there were no Pre- or Post-Application Projects.	Yes	Yes, however there were no Pre- or Post-Application Projects.
14	Includes description of process to develop projects solving Electric system needs	Yes	Yes	Yes
15	Includes description of method used to accommodate case when local known loads exceed CEC forecast growth for a given year	Yes, in GNA Section 2.5.	Yes, Whirlpool method described in Report.	No
16	Includes description of adjustments to achieve extreme weather adjusted historical loads	Yes	Yes	Yes.
17	Includes illustrative examples of each step in the process	No	Yes. SCE included a number of numerical examples.	No
18	Includes GNA Overview Summary Tables, Reform #4 DER Driven needs, Reform #6 Segment level reporting, Reform #14	Yes – Reform #4 Yes – Reform #6 Yes, PG&E requested and received a Motion for Extension of time for the line section analysis. This was provided as a supplement filing on Oct.15, 2021. PG&E reported the supplemental filing did not identify any additional Candidate Deferral projects.	Yes • Reform #4 Yes, (Provided – by service type and region, by service type and asset) • Reform #6 Yes, there are none in this cycle • Reform #14b Yes, described that segment level reporting not included in this cycle - Tools not ready, planned for future.	Yes, SDG&E did not identify any specific DER Driven projects in their GNA/DDOR Report – for Reform #6. Yes - for Reform #14 Yes - for Reform #4
19	Pre-Application Projects shall be identified as Tier 1, 2, or 3 in the GNA/DDOR filings and ranked using the same prioritization metrics and	No, there are no pre-application projects	Yes, SCE included two Pre-Application projects in the Tier 1, 2, and 3 table	N/A. There are no pre-application projects included

	methods applied to all other deferral opportunities Reform # 35		without values for the Forecast Certainty since this metric is not included for these two projects per CPUC requirement Reform #24 of the 2020 May ALJ Ruling.	in the GNA/DDOR.
20	The IOUs shall identify to Energy Division's CEQA Unit all projects that are expected to require General Order 131-D compliance within the 10-year planning horizon and have subtransmission or distribution components included in the DIDF on a quarterly basis. (Note: Reform 36 was updated to a semi-annual submission instead of quarterly, per ALJ ruling in June 2021) Reform # 36	PG&E has no projects that are expected to require GO 131-D compliance during this time horizon.	Yes, SCE has provided this report to Energy Division's CEQA Unit for Q2 and Q4 2021.	For the 10-year planning horizon, SDG&E has not identified projects with distribution components that are included in the DIDF.
21	The IOUs shall include information about the approval status of Pre-Application and Post-Application projects in the GNA/DDOR narrative and spreadsheets (i.e., DDOR planned investment and deferral opportunities spreadsheet lists) and prioritization metrics workbook of deferral opportunities. Reform # 37	PG&E has no Pre-application or Post-application projects.	SCE provided the requested information in its DDOR planned investment and deferral candidate sheets, its prioritization metrics workbook, and its Narrative.	SDG&E has no Pre-application or Post-application projects in this cycle.
22	The IOUs shall clearly identify conflicts (if any) between the DIDF and General Order 131-D in their recommendations for DIDF reform in the 2020 GNA/DDOR filings. Where conflicts are identified, the IOUs shall also recommend solutions. Reform # 38	PG&E has no projects that are expected to require General Order 131-D compliance within the 10-year planning horizon.	N/A, Reform 38 was addressed in 2020 Narrative Section. 3.4.	Yes, SDG&E indicated that there are potential conflicts that could impact customer reliability and increase customer costs. An example was provided wherein an amendment could be needed due to changes in the middle of the process that could require starting/redoing previously started environmental processes.

				Please also refer to the response for Item #20 in this table.
23	The IOUs shall identify DERs as the first contingency in their contingency planning process, and where third-party procurement is unsuccessful, shall consider full or partial IOU-ownership of a DER solution. Reform # 49	PG&Es contingency plan does consider DER as an initial option.	SCE indicated that DERs are considered in each of its contingency planning process.	SDG&E indicated that DERs would be considered when contingencies occurred. SDG&E mentioned that they will consider full or partial utility ownership, along with other options, to determine the most cost-effective and feasible contingency solution.
24	Includes discussion of IOU ownership option Reform # 2	Yes, PG&E discussed IOU ownership. Reform #2 – in PG&E's 2021 DDOR; there was one DER solution planned for IOU ownership: DDOR028 (Renz Energy Storage). PG&E also sought bids for IOU ownership for DDOR109 (Blackwell Bank 1) during its 2020-2021 DIDF RFO cycle, although no cost-effective bids were received.	Yes, SCE discussed IOU ownership. SCE did not evaluate SCE-owned DERs as solution alternatives in conjunction with traditional wires solutions as part of its 2021 annual planning process. SCE is still working through internal processes, software capabilities, technical training, and evaluation methodologies to enable engineers to evaluate SCE owned and operated DERs within its annual planning process. SCE described several DER pilots owned by SCE.	Yes, SDG&E discussed IOU ownership in the 2021 DDOR via consideration in SDG&E's Distribution Planning Process. No new IOU-owned DER projects were identified during the 2021 GNA/DDOR cycle.
25	Includes identification of any equipment necessary to integrate DERs with the grid that could feasibly be owned by a third party	Yes, PG&E is current evaluating if third party owned telemetry equipment could	Yes, proposed a 3rd party approach to communication equipment between	No equipment identified. SDG&E plans to address

	and discuss the pros and cons of third-party ownership. Reform #17	potentially replace IOU required reclosers or mini-RTUs for larger DER installations (I MW or larger).	SCE and DER as part of ongoing Rule 21 proceeding.	this in a future GRC.
26	Includes summary of planned investment	Yes, by project type, planning area, Distribution Service, service date, and LNBA range.	Yes, table of project type (Subtrans Line, Subtrans Sub and Line, Subtrans Substation, Dist. Substation, Dist. Sub & Dist. Feeder, Dist. Feeder, DER) and region Listed by service type, operating date, LNBA Range.	Yes
27	Data provided – structure/indices	Yes, Facility ID, GNA Need ID, DDOR ID, and Candidate Deferral Name also called Project Name.	DDOR Project ID, DDOR ID, and GNA ID	GNA ID, DDOR ID, Facility ID, Substation, Bank or Circuit.
28	Includes description of timing screen	Yes	Yes	Yes
29	Includes description of technical screen	Yes	Yes	Yes
30	Includes list of Candidate Deferral Projects	Yes, including associated Tier, In-Service Date, and Deficiency (MW)	Yes, tabulated by project type and region, by service, by operating date, and by LNBA range	Yes
31	Includes information for Candidate Deferral opportunities including: • Unit Cost of Traditional Mitigation, Contingency Plan, • DER Operational Requirements • Basis for Prioritization Metrics, and • LNBA values denominated in both MW and MWh.	Yes, Unit cost information is provided; DER operating requires include Real Time/Day Ahead, Calls/Year, and Duration; Prioritization metrics are described; and LNBA values are provided.	Yes, DER operating requirements including capacity needs, energy needs, hour of day, time of year, duration, monthly frequency, and yearly frequency.	Yes. The prioritization table included the listed information.
32	Includes DER Operating Requirements for Candidate Deferral projects?	Yes, for all potential Candidate Deferral Opportunities	Yes, SCE provided for all candidate deferral projects in the DDOR spreadsheet.	Yes. DER operating requirements including capacity needs, energy needs, hour of day, time of year, duration, and yearly frequency.
33	Includes Pre- and Post-Application Projects	Yes, general discussion of topic but no projects identified for ten-year planning horizon	Yes, provided table with 4 Pre and Post Application Projects (two each) and included in the prioritization	Yes, general discussion of topic but no projects identified for the ten-year planning horizon

			workbook discussed below.	
34	Includes list, description and explanation of Prioritization Metrics described Reform #31 (Approach) and #32 (Absolute ranking in the future)	Yes, prioritization metric information described. In response to stakeholder questions, PG&E stated "…is not opposed to moving to an absolute approach in the future, assuming all of the relevant information is included, and thresholds are set based on lessons learned from past DIDF cycles."	Reform #31Yes, SCE considered recommendation Reform #32 Yes, discussed. Indicated some advantages and pointed out that currently they are required to select 4 projects for SOC and PP pilots. SCE indicated that they believe the current Joint Prioritization Workbook Template includes the "best" of both absolute thresholds (via "flags" defined using engineering judgment and prior competitive solicitation experience) and relative ranking metrics.	Yes, the 2021 GNA/DDOR report includes a list, description and explanation of Prioritization Metrics. Reform #31: Yes, this was discussed in the 2020 GNA/DDOR, as required by the May 11, 2020 ruling. Reform #32: No. However, this was verbally addressed during the Joint IOU Pre-DPAG meeting. GPI was given an opportunity to discuss their proposal at a DPAG meeting, but GPI did not respond.
35	Includes description of Cost Effectiveness Metric and explanation of use Reform # 30 (Include LNBA/MWh-day for information)	Yes, description included. Includes LNBA/MWh-day value for informational purposes for each Candidate Deferral Project.	Yes, includes description and explanation of use of the new Joint IOU Prioritization Workbook Template. Reform # 30 - included for info LNBA/MWh-day values.	Yes. Includes description of Cost Effectiveness Metric and explanation of use. Reform: 30: Yes. LNBA/MWh-day is included in the prioritization workbook.
36	Includes description of Forecast Certainty Metric and explanation of use Reform #24B (describe weightings) and #24C (year of need)	Yes, the information is provided and explained.	Yes, as part of the new Joint IOU Prioritization Workbook. SCE also included description of 150% weighting of the cost effectiveness and market assessment	Yes. Includes description of Forecast Certainty Metric and explanation of use. Reform #24B. While the

			metrics for Pre-Application projects.	components of the Grid Need Certainty metric are described in the report, the weighting factors and the exact calculation methodology is not described. Reform #24C. Yes, the need date and operational date of the CDOs are included in the prioritization workbook.
37	Includes description of Market Assessment Metric and explanation of use	Yes, the information is explained.	Yes, as part of the new Joint IOU Prioritization Workbook.	Yes.
38	Includes description and explanation of use of the approach to place candidate deferral projects into tiers	Yes, description provided of how metrics are developed, and their scores are used in the Joint Prioritization Metric Workbook to develop a relative ranking of Candidate Deferral projects	Yes, as part of the new Joint IOU Prioritization Workbook.	Yes, SDG&E had two candidate deferral projects, and both were determined to be Tier 1 projects. Since there were only two Tier 1 projects in the 2021 GNA/DDOR, SDG&E provided the following explanation: “Commission-adopted staff proposal requires that at least one Tier 1 candidate deferral project be offered for the Partnership Pilot and at least one Tier 1 candidate deferral project be offered for the Standard Offer Contract pilot.”
39	Includes description of methodology to develop LNBA values and LNBA indices ($/kW, $/MWh, etc.)	Yes	Yes	Yes

40	Includes LNBA values calculated on 10-year basis - Reform #5	Yes	Yes	Yes
41	Includes description of Contingency Plan Approach and Methodology	Yes	Yes	No. However, SDG&E states that it reaffirms its commitment to considering whether DERs not selected in the RFO would be a cost-effective solution in the event the selected DER fails to perform.
42	Includes Data Redaction explanation for GNA, DDOR reports, and associated data	Yes, PG&E followed aggregation and anonymization rules. The primary component of these rules is the "15/15" rule which was explained.	Yes, explained 15/15 rule. SCE redacted Equipment Rating, Deficiency Percentage, Cumulative Demand, and Facility Loading Limit to the extent it could be used to derive customer energy usage or demand, and because it cannot be aggregated due to the location-specific nature of the reports.	Yes, explained use of 15/15 rule.
43	Data includes LNBA workbooks to be fully unlocked and functional with formulas in place and operable Reform #22	Yes	Yes	Yes
44	Includes DIDF Projects from Most Recent Cycle	Yes, Column B in DDOR Appendices A&B indicates if the project was included in a previous DDOR.	Yes, summarized results from previous solicitation.	N/A, SDG&E has not had any candidate deferral projects in previous cycles.
45	Includes description of how procurement process satisfies multiple procurement objectives. Reform #26	There is a discussion of sourcing by DIDF RFO, Partnership Pilot, and Standard Offer Contract Pilot	Yes, procured RA plus DER services. SCE does value stack when evaluating offers to defer selected projects as described in Reform #26.	Yes, SDG&E asserts that pursuant to Reform #26, it is not feasible to satisfy multiple procurement objectives given varying regulatory timelines and

				complications with the offer selection process. (See SDG&E reply comments to proposed improvements to the 2021 DIDF process, p. 3.)
46	Includes application of a 10-year planning horizon for Pre-Application Project needs included in the GNA but continue to apply a 5-year planning horizon for all other needs presented in the GNA. Reform #7	PG&E does not have or expect to have any Pre-application or Post-application projects within the 10-year horizon.	SCE has included Pre-Application projects within 10-year planning horizon in its GNA and DDOR. All other needs and projects within 5-year planning horizon were included in GNA/DDOR.	Yes, SDG&E did not have any Pre- or Post-Application projects; therefore, none were included in SDG&E's GNA/DDOR Report.
47	All grid needs are presented separately for the purpose of identifying planned investment and candidate deferral projects and applying the prioritization metrics to determine which projects to include in the DIDF RFO. Reform #12	Yes	Yes, different grid needs are presented separately in SCE's 2021 GNA and 2021 DDOR.	Yes
48	Includes forecast loading data for all feeders, not just feeders with deficiencies and be careful to follow the GNA/DDOR requirements specified in Appendix A to the May 7, 2019 Ruling unless refined by a subsequent ruling. Reform #13	Yes, load forecast for all distribution banks and feeders are included.	SCE provided forecast loading data for all feeders and for their corresponding distribution substations with low side voltage levels 33 kV and below.	Yes, load forecasts for all feeders included.
49	Circuit-segment level, line segments with needs, are included in the GNA. Reform #14	Circuit level analysis was included in the GNA. PG&E requested and received a Motion for Extension of time for the line section analysis. This was provided as a supplement filing on Oct.15, 2021 and not part of the IPE report. PG&E reported the supplemental filing did not identify any	SCE does not yet have the software tool capability to run line segment analysis and is currently developing this capability so that distribution planners can run load flows to identify line segment needs. Therefore, SCE did not include line segment level data	Yes

		additional Candidate Deferral projects.	within its 2021 GNA. Until SCE has this capability, SCE will continue to perform and document circuit level analyses for the GNA and DDOR.	
50	GNA/DDOR filing includes clear explanation for the removal of any grid needs due to phase balancing, transfer of loads, or the correction of modeling issues. Applies to SDG&E	GNA/DDOR discusses the elimination of any grid needs as a result of load transfers. No load balancing nor modeling issues were identified in the report.	N/A	Yes
51	The IOUs shall discuss a timeframe for adding detailed historical PSPS outage data to the maps and datasets hosted on the DRP Data Portals. Reform #11	No, per PG&E, the reform specified was done in 2021/2022 and need not be repeated.	N/A. The PSPS outage data was added to the maps on DRP Data Portals on August 31, 2021.	Yes, this was discussed in the 2020 GNA/DDOR filings.
52	All LNBA calculations to be included in the Joint Prioritization Workbook (Reform #21) which should be functioning and unlocked. Reform #20 to be approved by ED.	Yes	Reform #21 – Yes Reform #20 – Yes, approved by ED.	Yes
53	DRP Data Portal is to be updated with GNA/DDOR data by August 30.	PG&E reported the DRP Data Portal was updated with GNA/DDOR data by August 30, 2021.	Yes	Yes, SDG&E indicated that its DRP portal was updated on August 16, 2021 the same day that SDG&E filed their GNA/DDOR report.

2.2. CPUC DIDF Reforms

The following table lists the fifty-six CPUC DIDF Reforms including the description of the reform. The information in the Status column indicates whether the reform is 1) Included in the Report - meaning that it is discussed in the previous table, 2) Not included in this report - meaning that it is not discussed anywhere in this report, 3) Future - meaning the utilities implementation is expected in the future, or 4) An item covered by the Independent Evaluator (IE).

Table 2-2: List of Fifty-Six CPUC DIDF Reforms

Proceeding Status	Status
2. In the DDOR list of planned investments, the IOUs shall identify all DER solutions planned for IOU ownership or otherwise planned for procurement but not prioritized as deferral opportunities. In addition to including the same data provided for every other planned investment, the types of DER selected for IOU ownership (*e.g.*, storage, energy efficiency, etc.) and indicator that the project is excluded from prioritization shall be defined in sortable columns. If no IOU-owned DER solutions are listed in compliance with this reform, the IOUs shall explain why in their GNA/DDOR filing.	Included in this report.
Common Comparable Datasets	
3. The same IEPR datasets shall be used by all three IOUs in the preparation of their GNA/DDORs. The IOUs shall meet and confer to establish which IEPR datasets are used for forecasting and disaggregation and present a listing of the selected datasets to Energy Division for approval. In all cases, IEPR datasets shall be used where feasible for disaggregation and forecasting and the IOUs shall clearly state in the GNA/DDORs which datasets where used, including whether the draft or updated IEPR datasets.	Included in this report.
4. The IOUs shall provide tabulated summary tables showing the types and numbers of grid needs, planned investments, and candidate deferrals identified each cycle similar to the ones PG&E provided in their 2019 GNA/DDOR. Energy Division, in consultation with the IPE, will identify improvements and standards for the GNA/DDOR summary tables as needed for future DIDF cycles to support preparation of the IPE Post-DPAG Report.	Included in this report.
5. The IOUs shall calculate LNBA values for both planned investments and candidate deferrals based on a 10-year timeframe. If a project need (*i.e.*, peak MW shortfall) is not identified for the entire 10-year period, the largest forecast need identified may be used (*i.e.*, peak MW shortfall for year 5). If the IOUs would prefer to use LNBA ranges for planned investments, then the ranges shall be tighter than those provided in 2019, and the use of ranges shall be subject to approval by Energy Division prior to implementation.	Included in this report.
6. The GNA/DDOR filings shall include a description and listing of any DER-driven needs and the required equipment and steps taken by the IOU to develop any non-DER solutions to address the DER-driven needs. Steps planned or taken by the IOUs to upgrade monitoring and control systems to allow DERs to meet such needs shall also be described.	Included in this report.
7. The IOUs shall apply a 10-year planning horizon for Pre-Application Project needs included in the GNA but continue to apply a 5-year planning horizon for all other needs presented in the GNA.	Included in this report.
DRP Data Portals	
8. The IOUs shall identify the location of all planned investments on their DRP Data Portal maps and in the attribute data and other data provided on the portals.	Not included in this report.

9. The IOUs shall identify the location of all approved transmission projects on the DRP Data Portal maps such that they can be viewed at the same time as Grid Needs Assessment, Distribution Deferral Opportunity Report, ICA, and other data layers provided. The transmission projects shall be sortable (by layer) for CAISO approved, Commission approved, and internally approved by IOU/CAISO and Commission approval not required. Among the attribute data provided shall be the approval date and expected operational date. Additional projects or attribute data may be requested by Energy Division for posting based on the IOU's quarterly Assembly Bill 970 transmission reports, successor reports, or other sources. Where the precise alignment or location is not yet known, an estimate should be provided with a note that siting is not yet complete.	Not included in this report.
10. The IOUs shall include the fire threat and tree mortality data from the online Commission Fire Map as layers on the DRP Data Portal online maps and ensure the added data layers remain current.	Not included in this report.
11. In their recommendations for DIDF reform submitted in the 2020 GNA/DDOR filings, the IOUs shall discuss a timeframe for adding detailed historical PSPS outage data to the maps and datasets hosted on the DRP Data Portals.	Not included in this report.
Grid Needs and Deferral Screens	
12. The IOUs shall present all grid needs separately for the purpose of identifying planned investment and candidate deferral projects and applying the prioritization metrics to determine which projects to include in the DIDF RFO. For comparative purposes, the IOUs may also present prioritization results from combining grid needs for a deferral opportunity accompanied by an explanation of why the IOU believes the grid needs must be combined into a single deferral opportunity.	Included in this report.
13. The IOUs shall continue to provide forecast loading data for all feeders, not just feeders with deficiencies and be careful to follow the GNA/DDOR requirements specified in Appendix A to the *May 7, 2019 Ruling* unless refined by this *Ruling*.	Included in this report.
14. Specific to circuit-segment level (line segment) needs, the IOUs shall continue to perform and document the analyses as part of the GNA but may choose to list only the circuit segments for which needs are identified rather than listing all line segments in the GNA/DDOR filings. The IPE and Energy Division may request the entire listing of line segments as needed.	Included in this report.
15. SDG&E shall include clear explanations in their GNA/DDOR filing for the removal of any grid needs due to phase balancing, transfer of loads, or the correction of SDG&E modeling issues.	Included in this report.
Grid Modernization Plans and GRCs	
16. In their recommendations for DIDF reform filed in the 2020 GNA/DDORs, the IOUs shall describe projects that may be feasible to defer by DER, but do not meet the three-year timing screen, and discuss the possibility of a shorter timing screen for implementation in the 2020-2021 DIDF cycle. The IOUs shall also discuss the requirements that would enable forecasts of circuit-segment and voltage and/or reactive power needs beyond three years.	Included in this report.

17. The IOUs shall identify any equipment necessary to integrate DERs with the grid that could feasibly be owned by a third party and discuss the pros and cons of third-party ownership in their DIDF reform recommendations provided with the GNA/DDOR filings. High-level costs estimates shall be provided with any equipment identified including estimates for the amount of equipment to be required within the next 10 years.	Included in this report.
18. The IOUs shall apply to their 2020 GNA/DDOR filings a grid needs ID, facility ID, and project ID numbering system similar to the one in SCE's 2019 GNA/DDOR. All DIDF project ID numbers shall be unique and directly link to specific projects in an IOU GRC. Where the IOUs require differences in numbering approach due to internal organizational or database systems, they shall implement the custom approach for 2020 with an explanation in their recommendations for DIDF reform. Energy Division shall review the numbering approaches applied for the 2020 filings and approve the numbering systems to be used for the 2021 GNA/DDOR and future filings.	Included in this report.
Prioritization Metrics	
Prioritization Metrics Workbooks and Joint Template	
19. The IOUs shall develop a common prioritization metrics spreadsheet template based on SCE's 2019 prioritization metrics workbook. It shall be called the ***Joint Prioritization Metrics Workbook Template***.	Included in this report.
20. The IOUs will reach a common understanding of each label, heading, and formula used in SCE's 2019 prioritization metrics workbook and apply the same labels and formulas in the template or document any improvements to SCE's labels, headings, and formulas. The IOUs shall present their final, 2020 Joint Prioritization Metrics Workbook Template to Energy Division for approval on or before **June 1, 2020** or as determined by Energy Division.	Included in this report.
21. All LNBA calculations shall be included in the IOU's 2020 prioritization metrics workbooks.	Included in this report.
22. The Excel prioritization metric workbooks and LNBA data filed with the GNA/DDORs shall be fully unlocked and functional with all formulas in place and operable. Regardless of whether the IOUs believe the workbooks contain confidential data, they shall be provided to Energy Division. In parallel, the IOUs shall file a motion requesting confidential treatment if they believe specific data to be confidential. To the extent fully operable Prioritization Metric Workbooks with all LNBA data included cannot immediately be made public upon filing, a complete PDF of all worksheets shall be filed in addition to the Excel workbooks with only the necessary redactions made.	Included in this report.
23. At such time as Energy Division determines that further improvements to the prioritization metrics template, IOU-specific workbooks, or underlying metrics or data are to be made, Energy Division shall make this determination and require the IOUs to implement them, as time allows, for the current DIDF cycle or future ones.	Future
Forecast Certainty Metric and Qualitative Assumptions	
24. The IOUs shall include in the Joint Prioritization Metrics Workbook Template a ***table of guidelines*** to direct Forecast Certainty metric application. The table of guidelines will clarify factors that could delay or accelerate project need and establish "Likelihood of Project" numerical values. In addition:	Included in this report.

a. The IOUs shall review the design of the Year of Need and Likelihood assumptions of the metric to ensure one does not inadvertently dominate or override the other component and document the results of this review in the annotated Joint Prioritization Metrics Workbook Template. It may be that only one or the other assumptions should be applied to the metric.	Included in this report.
b. The IOUs shall describe all weightings they apply to combine the components of the Forecast Certainty metric into a single score.	Included in this report.
c. The need date shall be used for Forecast Certainty metric calculations. The expected operational date shall also be identified in the workbooks for informational purposes.	Included in this report.
d. For Pre-Application Projects, the IOUs shall still provide the Forecast Certainty metric data but shall not apply the calculated Forecast Certainty metric results to the prioritization ranking of these projects.	Included in this report.
25. To further improve on SCE's 2019 prioritization metrics workbook, the IOUs shall:	
a. Annotate their 2020 workbooks to ensure all labels, headings, and formulas used are described and that each spreadsheet column has a defined heading.	Included in this report.
b. Seek to quantify all qualitative values and fully define such values within the workbooks. The quantification of qualitative values shall be based on ***scoring rubrics*** (*i.e.*, a table of guidelines) and include explanatory narratives.	Included in this report.
c. Fully describe and document all qualitative values that the IOUs determine not to be quantifiable, including the reason the values cannot be quantified.	Not included in this report.
Consideration of Value Stacking	
26. The IOUs shall seek to satisfy multiple procurement objectives where feasible. In such instances, this may result in deferral projects that exceed the cost cap because the procurement also satisfies other regulatory procurement objectives.	Included in this report.
27. The IOUs shall provide narratives about expected value stacking opportunities for each candidate deferral in their GNA/DDOR filings and any requested by Energy Division. Among the concepts to discuss shall be compatible participation in various wholesale markets and other value streams from which the utilities would otherwise have spent capital.	Included in this report.
28. To the extent PG&E already included value stacking within its 2019 prioritization metrics, this shall be discussed with the other IOUs as they complete their Joint Prioritization Metrics Workbook Template for Energy Division approval and the outcomes shared with the DPAG stakeholders as recommendations for potential future DIDF reform.	Included in this report.
LNBA Data	
29. The underlying LNBA data shall be provided, including discount rate, revenue requirement multiplier, inflation assumptions, O&M factor, and book life. These and any other key assumptions shall be included in the 2020 prioritization metrics workbooks filed by the IOUs. The IOUs shall tabulate all assumptions they used in the LNBA model, as well as provide the sources/basis behind these assumptions in their GNA/DDOR reports.	Included in this report.

30. The IOUs shall include, for informational purposes, the LNBA/MWh-day value for each candidate deferral project in their 2020 prioritization metrics workbooks.	Included in this report.
Cost Effectiveness Metric and Project Cost	
31. The IOUs shall discuss in the 2020 GNA/DDORs the potential for 2021-2022 DIDF cycle reforms related to the IPE's recommendation about the general importance of the Cost Effectiveness metric.	Included in this report.
32. In their recommendations for potential 2021-2022 DIDF cycle reforms, the IOUs shall consider GPI's comments about prioritization changing from a relative ranking among the candidate deferral projects identified each year to a ranking based on baseline/absolute threshold values that would carry over each year.	Included in this report.
33. The cost of planned investments and deferral opportunities (unit cost) reported in the GNA/DDOR and applied to prioritization calculations shall include all deferrable (unspent) costs, including regulatory and permitting costs. The cost shall reflect the total project cost based on the latest, most accurate information at the time of filing. Upon request, the IOUs shall be prepared to itemize regulatory, permitting, or other costs that are already spent or otherwise not deferrable.	Included in this report.
34. If the cost of a planned investment or deferral opportunity conflicts with the corresponding project cost reported in an IOU's same-year GRC filing, the IOU shall, in the GNA/DDOR, identify the GRC-specific cost and explain the discrepancy. Pursuant to D.18-02-004, Ordering Paragraph 2h., the discrepancy must also be presented in the GRC testimony.	Future
Pre-Application Projects	
35. Pre-Application Projects shall be identified as Tier 1, 2, or 3 in the GNA/DDOR filings and ranked using the same prioritization metrics and methods applied to all other deferral opportunities (except as otherwise noted in this *Ruling*, *e.g.*, Forecast Certainty metric, Reform No. 24d). Once filed with the Commission in the form of an application pursuant to General Order 131-D, all Post-Application Projects will continue to be evaluated like any other deferral opportunity in the GNA/DDORs unless otherwise directed by the proceeding opened for the Post-Application Project.	Included in this report.
36. The IOUs shall identify to Energy Division's CEQA Unit all projects that are expected to require General Order 131-D compliance within the 10-year planning horizon and have subtransmission or distribution components included in the DIDF on a quarterly basis (or as requested by Energy Division) and include data found in the Assembly Bill (AB) 970 or successor reports (*e.g.*, confidential cost, approvals required, and approval status). For each project identified, the IOUs shall indicate which approvals are required (*e.g.*, internal to IOU, CAISO, Commission) and, if the approvals have not yet been attained, when they are expected to be attained. Similarly, projects listed in the IOU's quarterly, AB 970 reports (or successor to the reports) with components included in the DIDF shall be identified to Energy Division at the time of AB 970 report or successor filing.	Included in this report.
37. The IOUs shall include information about the approval status of Pre-Application and Post-Application projects in the GNA/DDOR narrative and spreadsheets (i.e., DDOR planned investment and deferral opportunities spreadsheet lists) and prioritization metrics workbook of deferral opportunities. For example: CAISO approval on, expected on [year or N/A]; Commission GO 131-D application (and type) filed on, expected on [year or N/A]; and internally approved by IOU on [year or TBD].	Included in this report.

38. The IOUs shall clearly identify conflicts (if any) between the DIDF and General Order 131-D in their recommendations for DIDF reform in the 2020 GNA/DDOR filings. Where conflicts are identified, the IOUs shall also recommend solutions.	Included in this report.
Requests for Offers	
Procurement Process Review, Monitoring, and Reporting	
39. At the request of Energy Division, the IOUs shall present new or alternate deferral opportunities for analyses during the DPAG review process.	Not included in this report.
40. The IOUs shall continue to file a Tier 2 Advice Letter recommending distribution deferral projects to be included in the DIDF RFO process. In addition, the IOUs shall file a separate Tier 2 Advice Letter on November 15th requesting approval to not include in the DIDF RFO process any remaining candidate deferral opportunities identified in their GNA/DDOR filings or by DPAG stakeholders or Energy Division.	Not included in this report.
41. The IOUs are required to file a Tier 2 Advice Letter for contract approval. If the forecast and operational requirements do not change, however, the IOUs need not file the Advice Letter for contract approval. Instead, an Information-Only Submittal (*see* General Order 96-B) may be filed with Energy Division upon contract execution that includes a project description, summary of bid and procurement outcomes, the executed contract (in full and without redactions), and any other information as required by the Energy Division.	Not included in this report.
42. The *May 7, 2019 Ruling* requires the IOUs to file a Tier 2 Advice Letter to explain changes to DIDF project forecast and operational requirements subsequent to the November 15 filing date. This *Ruling* clarifies that a Tier 2 Advice Letter is also required for changes to cost caps (deferral values) and planned investment costs subsequent to the November 15 filing date.	Not included in this report.
a. An Advice Letter need not be filed, however, for minor changes to forecasts, operational requirements, or cost caps that do not impact deferral viability. Energy Division staff shall still be notified of the minor changes.	Not included in this report.
43. When DIDF project contract execution is delayed, the IOUs may request an extension from the Energy Division Director rather than the Commission's Executive Director. The extension request shall explain the reason for the request, propose an extension timeframe, and provide a rationale for the requested timeframe.	Not included in this report.
IOU Ownership	
44. The IOUs shall encourage bids for all forms of resource ownership (e.g., utility-owned, third-party owned, customer-owned, joint ownership) in their DIDF RFOs, allowing for bid participation and evaluation without any bias towards a specific ownership model. Procurement outcomes of the 2020-2021 DIDF cycle shall be reviewed during the 2021-2022 DIDF cycle at the discretion of Energy Division in coordination with the IPE and IE to determine if policies are required to ensure fairness among bidders.	Not fully included in this report. Future.
45. The IOUs shall identify issues (if any) related to IOU ownership, Energy Resource Recovery Account cost recovery, and IOU procurement on behalf of bundled customers in their recommendations for DIDF reform in the 2020 GNA/DDOR filings.	Included in this report.

Incrementality and Multiple-Use Applications	
46. The IOUs shall adopt PG&E's February 7, 2020 clarifying text or develop similar text to clarify SGIP, NEM, end Energy Efficiency incrementality, and include the text in their 2020-2021 DIDF RFO materials. The draft text shall be included in each IOUs GNA/DDOR as reform recommendations and then presented during the 2020 DPAG to receive feedback. The text shall be reviewed by Energy Division prior to RFO launch.	Not included in this report.
Day-Ahead Dispatch Requirements	
47. SCE shall report the results of their event-driven projects included in their RFO for the 2019-2020 DIDF cycle to Energy Division, the IPE, and participants of the 2020 DPAG and include a discussion in their recommendations for potential DIDF reforms in their 2020 GNA/DDOR filing. The discussion shall focus on how the approach taken by SCE impacts the desirability of DER solutions and the calculation of prioritization metrics (especially where LNBA/MWh-year is applied). PG&E and SDG&E shall also consider SCE's day-ahead dispatch requirement in their recommendations for potential DIDF reforms.	Included in this report.
Contingency Planning and Contingency Cost Recovery	
48. The IOUs shall include options in DIDF RFO contracts for the procurement of DER resources above minimum performance and/or operational requirements to the extent it remains cost effective. It follows that where forecast or operational requirements changes occur post RFO launch, the IOUs shall seek to address the changes within the solicitation framework to the maximum extent possible rather than relaunching the RFO.	Future
49. The IOUs shall identify DERs as the first contingency in their contingency planning process, and where third-party procurement is unsuccessful, shall consider full or partial IOU-ownership of a DER solution.	Included in this report.
50. With each GNA/DDOR filing, the IOUs shall append or separately provide to Energy Division a report organized by deferral opportunity that contains itemized data on any payments made to contracted deferral projects and all spending on contingency plans for each deferral opportunity. The reporting shall include any modifications or additional details required by Energy Division. The reporting shall include all candidate deferral projects launched in a DIDF RFO since 2018 and will continue to cover this timeframe unless modified by Energy Division. Additional reporting guidelines apply on GRC filing years pursuant to D.18-02-004, Ordering Paragraph 2.dd.	Future
51. The IOUs are allowed to track contingency plan spending in their Distribution Deferral Balancing Account and seek recovery for costs reasonably incurred in their General Rate Case. Approval of any costs tracked shall occur in the General Rate Case. All contingency plan spending shall be itemized by DIDF RFO project for General Rate Case filings rather than summarized and aggregated.	Not included in this report.
52. The IOUs shall not request pre-approval of cost recovery for contingency plans in Advice Letters requesting approval of DIDF RFO contracts or otherwise make the approval of such requests a requirement for the Energy Division to approve DIDF RFO contracts.	Not included in this report.

IE Scope of Work	
53. IE-specific reforms for the 2020-2021 DIDF cycle are implemented within the IPE Scope of Work presented in Attachment C. The IE shall report to Energy Division to prepare its deliverables and conduct its analyses for DIDF implementation.	IE
54. IOU contracts with the IE for the full scope of work identified in Attachment C shall be executed by the IOUs to allow for IE participation in DPAG activities as soon as possible, ideally on or before June 1, 2020 and as defined in Attachment C for all subsequent years.	IE
55. The IE scope of work may be modified by Energy Division as needed for the IE to successfully complete each assignment. The IOUs will promptly submit a Tier 1 Advice Letter to notice changes in scope should a scope change differ significantly from the scope described in Attachment C. Minor changes should not necessitate an Advice Letter filing.	IE
56. Any IOU additions to the IE scope of work for DIDF RFOs shall be presented to Energy Division for approval at least 10 days before IE contract execution.	IE

2.3. Observations, Conclusions, and Recommendations

None at this time.

3. Load Forecasting – Known Project Load Growth

In this section we discuss the method that the three utilities used to include known load growth projects into their distribution circuit load forecasts.

3.1. Background

The three IOUs use known load projects in conjunction with the CEC IEPR forecasts to forecast the load growth for the GNA planning period. The term Known Load Projects is used in general by all three utilities to mean load growth for new or additional load that is based upon customer request for new service. As such, known load projects are site specific and provide insight into the circuits on which load growth is likely to occur.

While all the three utilities use known load projects to reflect load increases in their circuit-level load forecasts, they use different approaches in accounting for these projects. The purpose of this section is to review the approaches used by the utilities for including known load projects in their load forecasts and to develop recommendations for possible improvement.

Definitions Used in This Report

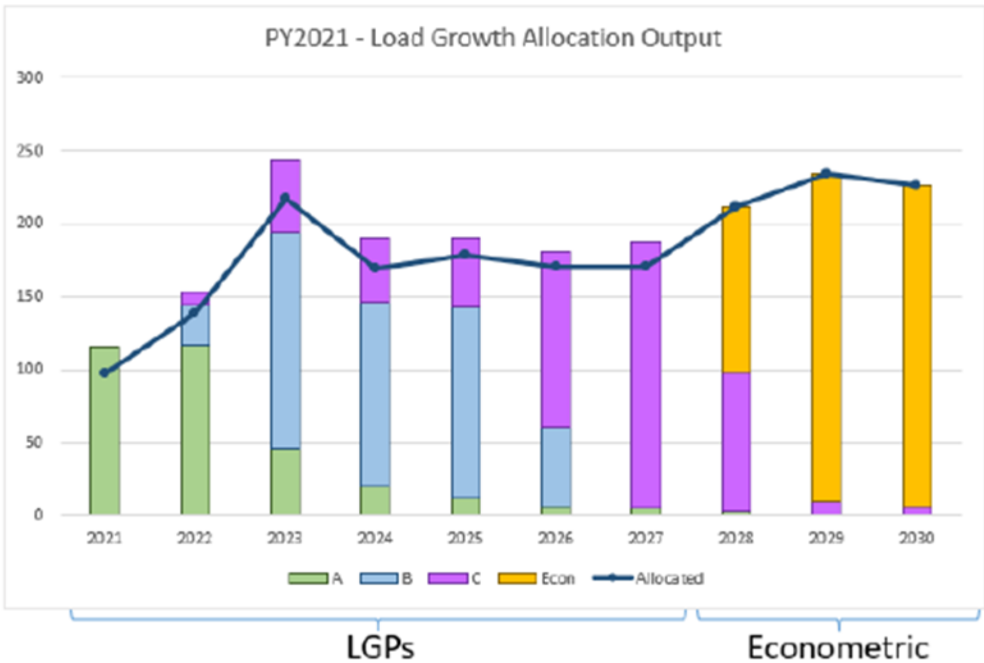
- **Known Load Projects** – "Known load projects" or "known load" additions, or simply "known loads" are forecasts of load growth that are based upon the requests for service from residential, commercial and industrial customers received by the utility. This is a term that is used by all three utilities in their reports in one form or another.
- **Embedded Known Loads** – Embedded known loads are those loads that are already accounted for in the CEC IEPR forecasts. This is a term that is currently used primarily by SCE to apply on a year-by-year basis.
- **Incremental Known Loads** – Incremental known loads are those loads that are in addition to the load growth forecasted in the CEC IEPR forecast. This is a term that is currently only used by SCE to apply on a year-by-year basis.

3.2. Treatment of Known Loads in the Grid Needs Assessment

Southern California Edison

SCE uses both embedded and incremental known load projects in their GNA. SCE developed a methodology, the "Whirlpool" method, to ensure that embedded known loads and economically driven load growth included in any year 1) do not exceed the CEC growth forecast for that year, 2) embedded known loads that are included first are ones that have the highest Level of Certainty (LOC), and 3) all embedded known loads are in fact included in the forecast over the planning period and therefore none are "lost" in the process. The Whirlpool method is described in detail in the 2021 IPE DPAG Report (Public Version) on Page 17. The net result of the application of the Whirlpool method in the 2021/2022 DIDF cycle is that individual embedded known loads made up all of the load growth for 7 years (2021-2027) in the CEC IEPR forecast after which load growth at the circuit level was determined by using econometric disaggregation of the remaining CEC load growth at the system level. Econometric variables are used in years eight and beyond to allocate to the circuit level the remining load growth in the CEC IEPR forecasts. This result can be seen in Figure 3-1 where the CEC annual load growth is represented by the blue line. It should be pointed out that this figure does not include the incremental load growth projects which are added on top of the loads shown.

Figure 3-1: Embedded and Economic Load Growth (SCE Provided Chart)



SCE also includes incremental load growth projects which are incremental to the loads forecasted in the CEC IEPR. These incremental loads fall into four categories in the 2021/2022 DIDF cycle (shown in largest to smallest order) – 1) Cultivation operations, 2) EV supercharging stations, 3) Load WDAT, and 4) Temporary Power and Customer Substations. SCE has been working with the CEC toward including all known loads in the CEC IEPR which would eliminate the need for SCE to utilize incremental known loads at all.

The incremental known loads in the 2021/2022 DIDF for the first five years were 450 MW, 200 MW, 180 MW, 60 MW, and 50 MW respectively. Thus, for the first five years, the load forecast used by SCE is higher than the CEC IEPR forecast by the amount of these annual incremental loads.

To make it easier to compare the SCE data with the data plotted for PG&E and SDG&E later in this section, the following two plots were created which show annual known loads and cumulative known loads for both embedded and incremental known loads.[2]

Figure 3-2: SCE Annual Load Growth 2021 DIDF

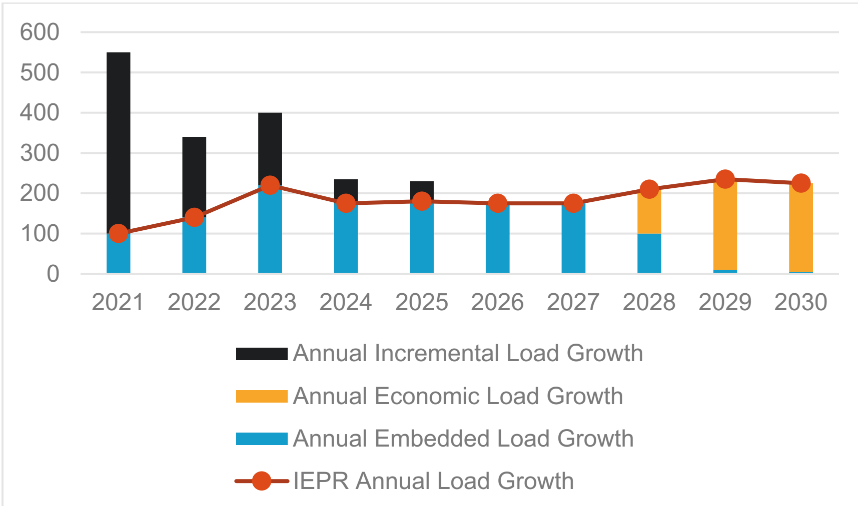
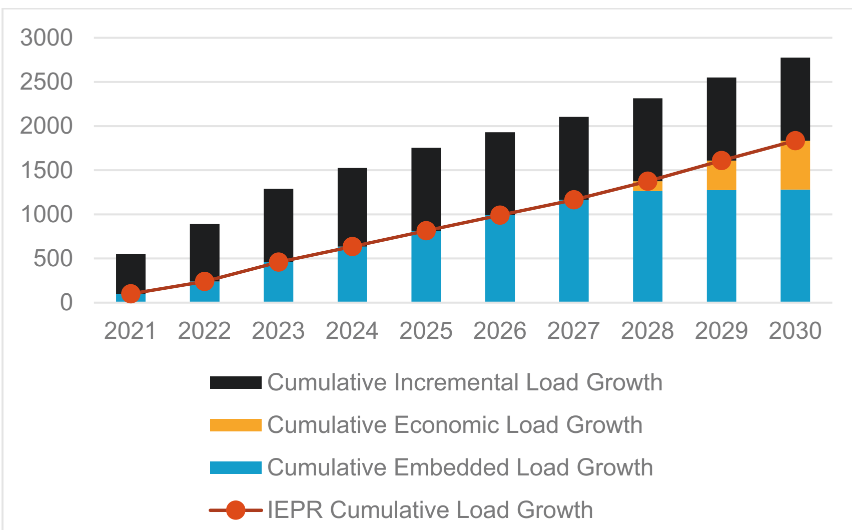


Figure 3-3: SCE Cumulative Load Growth 2021 DIDF



Pacific Gas & Electric

PG&E also uses known load projects in their GNA. However, they do not separate their known load projects into embedded and incremental like SCE. PG&E considers all of their known loads as being

[2] These two plots were developed, in part, with data that was pulled from SCE's chart. As a result, the data plotted should be accurate to within 10MW.

included in the CEC IEPR when considering the entire 10-year planning period as explained below. PG&E's methodology to determine how many of the known load projects to place into individual years and to complete the 10-year forecasting process is as follows:

- PG&E includes 100%, 90%, and 80% of the first three-year average known load projects (by customer class) in year 1, 2, and 3 respectively of the forecast period (i.e., 2021, 2022, and 2023). This is to reflect the fact that the loads associated with new service requests for the years 2022 and 2023 are less likely to materialize than those for the year 2021.
- For the remaining years (i.e., 2024-2030), PG&E uses the actual known load projects for those years.
- PG&E does not make any adjustments to the known load growths calculated as shown above, if they happen to exceed the CEC IEPR forecast in any given year. This can be seen occurring in the years 2021-2023 in Figure 3-4.
- PG&E also includes economic load growth in their load growth forecasts. PG&E includes economic growth in years up to the point that the total load growth over the 10-year planning period (known load and economic growth) is equal to the total load growth over the 10-year planning period in the IEPR as shown in Figure 3-4. As a result, PG&E's total load growth over the planning period is the same as the IEPR total value but its load growth forecasts in specific years can and do exceed the CEC annual values as seen in Figure 3-4. From Figure 3-4 it is evident that the load growth PG&E uses in the distribution needs determination in all years from 2024 to 2029 is less than the CEC IEPR load growth in those years. This is a result of PG&E ensuring that the total load growth it uses over the 10-year planning period is equal to the total load over that same period for the CEC – annual load growth above the CEC values in 2021-2023 must be offset by annual load growth below the CEC values for 2024-2029.

The annual and cumulative load growths due to known load projects and economic load additions, as well as the IEPR forecasts are shown in Figure 3-4 and Figure 3-5 respectively. As seen in Figure 3-4, the annual load growth modeled in the GNA is higher than the values in the IEPR forecasts for the first three years of the study. On a cumulative basis, the loads used in the GNA are higher than those from the IEPR until the very last year (i.e., 2030) of the study. The known load projects in the first few years are primarily from EV chargers and cannabis cultivation.

Figure 3-4: Annual known load growth, economic load growth and IEPR forecast

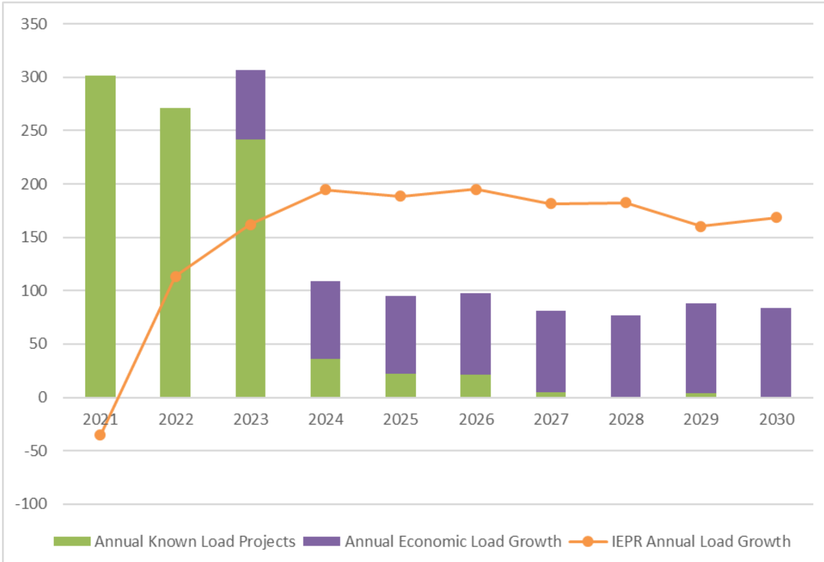
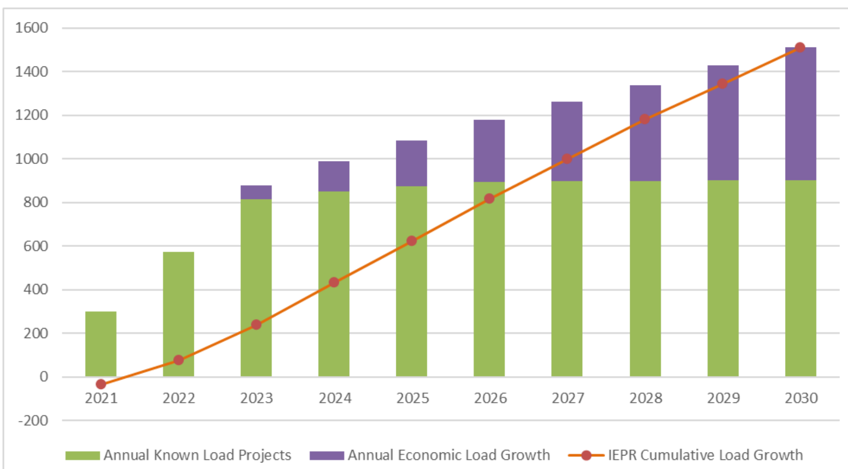


Figure 3-5: Cumulative known load growth, economic load growth and IEPR forecast



San Diego Gas & Electric

SDG&E's approach for treating known load projects is similar to PG&E's. However, unlike PG&E, SDG&E does not average or discount the known load projects. SDG&E models 100% of the known load projects in the year in which they are forecasted to occur. SDG&E also adds economic load growth projects to their forecast when the cumulative known loads is less than the cumulative IEPR forecast for any given year. The process that SDG&E uses for handling known loads is discussed in detail in Section 7.1.2 of the SDG&E 2021 IPE DPAG report.

The annual and cumulative load growths due to known load projects and economic load additions, as well as the IEPR forecasts are shown in Figures 3-6 and 3-7 respectively. As seen in Figure 3-6, the annual load growth modeled in the GNA is higher than the values in the IEPR forecasts for only the first year of the study. On a cumulative basis, the loads used in the GNA are higher than those from the IEPR until the third year (i.e., 2023) of the study. The known load projects in the first few years are primarily from new commercial loads including business, transportation, hospitals, parking, military, and farming. A breakdown of the known load projects can be found in Section 7.1.4 of the SDG&E 2021 IPE DPAG report.

Figure 3-6: Annual known load growth, economic load growth and IEPR forecast

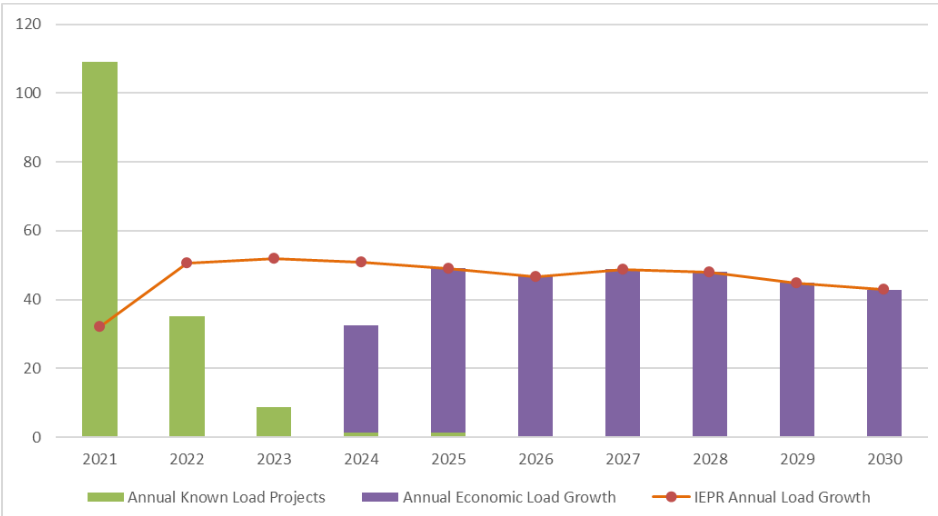
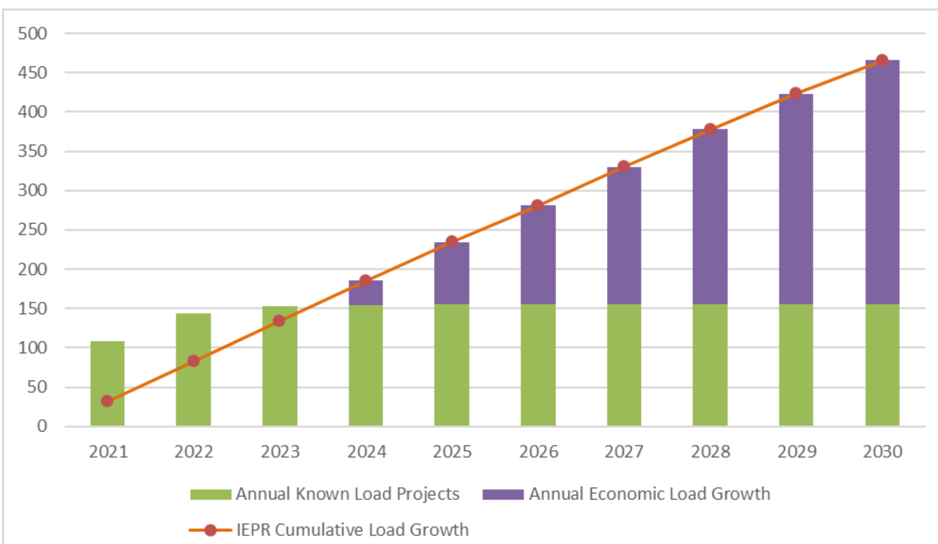


Figure 3-7: Cumulative known load growth, economic load growth and IEPR forecast



3.3. Observations, Conclusions, and Recommendations

The IPE makes the following observations regarding the methodology used by the three utilities in the treatment of known load projects in the GNA.

- SCE uses both embedded and incremental known load growth projects in their GNA which resulted in load growth that exceeds CEC IEPR load growth in some early years and over the 10-year planning horizon.
- PG&E and SDG&E use known load projects in their GNA that are accounted for in the CEC IEPR over the 10-year planning period but exceed the annual CEC values in the early years.
- SCE spreads the embedded known loads such that the IEPR annual load growth forecasts are not exceeded. However, since SCE models the incremental known loads on top of the embedded loads, the forecasts that they use in their GNA will always be higher than the IEPR forecasts as long as there are incremental loads. As mentioned earlier, SCE has been working with the CEC toward including all local known loads in the CEC IEPR which would eliminate the need for SCE to utilize incremental known loads.
- PG&E averages and discounts (by applying factors of 100%, 90%, and 80% for years 1, 2, and 3 of the forecast) PG&E known load projects, whereas SCE and SDG&E don't appear to be averaging or discounting their known load projects.
- PG&E and SDG&E do not adjust their known loads projects down if they are higher than the IEPR annual load growth forecasts. As such, the forecasts that they use in their GNA will be higher than the IEPR forecasts as long as there are known loads (adjusted in the case of PG&E) that are higher than the IEPR annual load growth forecasts.
- As a result of including known loads, in the 2021 GNA, the annual load growth is higher than the IEPR annual forecast value for the first 5 years for SCE, for the first 3 years for PG&E, and for the first year for SDG&E.
- We observe that for PG&E and SDG&E placing the known loads in years 1-3 would seem to improve the accuracy of the forecasts for those years since they are based upon customer service requests. We further observe that reducing the load growth in the years after this initial period in order to match the IEPR forecast loads over the planning period, has the result that forecast loads used in PG&E's and SDG&E's Distribution Planning Process in those later years are below the levels that the CEC expects will actually exist.
- In the 2021 GNA for all three utilities, the cumulative load growth in the first three years (2021-2023) is higher than the cumulative IEPR forecast for the same period. For SCE and SDG&E, the cumulative load growth in the first five years (GNA study period) is higher than the cumulative IEPR forecast for the same period.
- For the PG&E and SDG&E approach, the higher load growth in the first three years (or less) of the study tend to push the needs into these years at the expense of fewer needs in years 4 and 5. Since Candidate Deferral Opportunities (CDOs) are driven by needs primarily in years 4 and 5, this will result in fewer CDOs when compared to a case where the actual annual IEPR forecasts for years 4 and 5 are used.
- The IPE also observed that many of the known load projects are due to transportation electrification. Since the load due to EV chargers and other DERs are modeled explicitly by all three utilities, there is a possibility for double counting, i.e., including transportation

related loads as known load projects, as well as modeling them explicitly as Electric Vehicle Supply Equipment (EVSE) loads.

The IPE has the following recommendations regarding the treatment of known load projects in the GNA.

- We recommend that an approach similar to what is being employed by SCE be considered by PG&E and SDG&E. This recommendation goes along with the next recommendation. As mentioned, with SCE's approach, the sum of the embedded annual known load projects and economic loads do not exceed the annual IEPR forecast. As long as the utilities' coordination with the CEC results in the CEC accounting for/agreeing with the incremental known load projects in future IEPR forecasts, the result will be all three utilities using the same process to reflect embedded and incremental loads.
  One other area that we recommend should be considered is whether the embedded and incremental known loads are discounted in some fashion similar to PG&E's approach to reflect that some customer requests may be delayed, reduced or cancelled. Based on the level of incremental known load growth identified by SCE for the 2021/2022 DPP cycle, it seems possible that the CEC's IEPR forecast for the early years of the forecast period will be higher than what the CEC is currently estimating if this incremental known load growth is accounted for in the CEC's IEPR forecast. Thus, accounting for incremental known load growth within the CEC's IEPR forecast would be a critical part of the load growth forecasting process.
- Given the importance of how known loads are implemented in the future, especially incremental loads, we recommend that in addition to maintaining up-to-date known load project databases and sharing them with the CEC, the IOUs report data sufficient for someone to track whether specific known load projects materialize (e.g., unique project identifier, impacted circuit, initial service request date, load amount, and expected online date). The data to track should be selected as appropriate to facilitate an annual review of forecast accuracy as well as planning for the next forecast. Among the data tracked could include whether the project was considered an embedded or incremental known load and type of load (e.g., agricultural pump, cultivation, housing development, WDAT). Most of these data are already being tracked by the IOUs, but it is recognized that implementing a historical data tracking and reporting system could require database updates and be time intensive. The level of complexity required for this effort should be considered by the IOUs in coordination with the CEC and CPUC. This information could be useful in developing discounting factors (discounting known loads that have a lower probability of materializing) as appropriate and provide additional transparency in the process.
- In addition, the utilities should include a detailed review of their use of embedded and incremental known loads in their GNA/DDOR filings including but not limited to types of loads, number, amounts, timing, summary of embedded and incremental loads, etc.
- We recommend that the utilities collaborate (or continue to collaborate) with the CEC on improving the IEPR forecasts by exchanging information on modelling and assumptions used in the utilities and the CEC's their respective load forecasts.

- We recommend that the utilities document how they handle known load projects related to transport electrification. In particular, whether these transport electrification-related loads are modeled as known load projects or explicitly as EV (DER) load adjustments.

4. Candidate Deferral Project Prioritization Methodology

In this section we will review four aspects of the methodology used by the utilities to rank/prioritize candidate deferral project opportunities (CDO). The utilities used for the first time in the 2021/2022 DIDF cycle a (for the most part) common prioritization methodology. This methodology was implemented using an Excel Workbook. The workbook is known as the Joint Prioritization Metrics Workbook Template.

4.1. Forecast Certainty Metric

In this subsection we discuss the Forecast Certainty Metric (one of three used in the ranking of projects) and the Grid Need Certainty sub-metric. The purpose of this metric is to provide a relative indication of the certainty of the forecasted need(s) for candidate deferral projects.

In their DDOR Reports, each of the IOUs state this purpose slightly different.

- PG&E states the Forecast Certainty Metric is intended to give a relative indication of the certainty of the forecasted grid need,
- SCE states the Forecast Certainty Metric provides a relative indication of the likelihood of the grid needs driving a candidate deferral project materializing, and
- SDG&E states the Forecast Certainty Metric is intended to give a relative indication of the certainty of forecast grid needs.

The Forecast Certainty Metric which is included in the Prioritization Workbook consists of two sub-metrics, Grid Need Certainty and Year of Need. All three IOUs utilize these same two sub-metrics, but how they develop them is different.

The Year of Need sub-metric is used as a qualitative sub-metric (Flag) that if set would result in a project being placed into Tier 3. Also, since it is a qualitative sub-metric, it does not impact the Forecast Certainty numerical score used to rank projects. This Flag is set if the project need date is later than a threshold year.

The Grid Need Certainty is a quantitative sub-metric determined from a questionnaire completed by subject matter experts. The questionnaires used vary considerably by utility.

Review of PG&E Approach

- PG&E uses a Forecast Questionnaire completed by Planning Engineers for each CDO. It consists of 13 components that we have grouped into four logical groupings. The four groups are:
  - the risk of failure of a transformer bank for projects that rely on the continued operation of a substation transformer if a DER solution is implemented,
  - the likelihood that the area served by the asset forecasted to overload will connect new specific large energy loads in the near future for load that has not yet been requested by customers,
  - the potential impact of water allocation, temperature, and Covid, and
  - the type of operational benefit the traditional project would provide if constructed.

The 13 components are listed in the Table below.

Table 4-1: PG&E Forecast Questionnaire

Group	Component Number	PG&E Forecast Questionnaire
Risk of Bank Failure	1	If bank is being replaced by capacity project, what is risk of asset failure based on condition?
Likelihood of Connection of New High Energy Load	2	What is the likelihood that the area served by asset will need to connect new EV charging stations?
	3	What is the likelihood that the area served by asset will connect new cannabis cultivation?
	4	What is the likelihood that the area served by asset will need to connect new agricultural pumps?
	5	What is the likelihood that the area served by asset will need to connect high tech growth including campuses and data centers?
Potential Impact of External Factors	6	How strongly does the load on the asset forecast to overload correlate to State and Federal water allocation each year?
	7	How strongly does load on the asset forecast to overload correlate to temperature?

	8	What is the impact on load in this area based on Covid adjustments?
Operational Benefit Provided by Project	9	What kind of operational benefit does the project provide? OP Flex 1 - New Substation
	10	What kind of operational benefit does the project provide? OP Flex 2 - New Substation Transformer
	11	What kind of operational benefit does the project provide? OP Flex 3 - Replaced Substation Transformer
	12	What kind of operational benefit does the project provide? OP Flex 4 - New Circuit Breaker
	13	What kind of operational benefit does the project provide? OP Flex 5 - Line Work Creates Tie

The responses to the questions that are allowed in the questionnaire for the first three groups are - High, Medium, Low, or None. These scores are assigned to each response as shown in the following table. We can see that the scores increase with uncertainty – the larger the number the less certain the load forecast.

Table 4-2: Forecast Questionnaire Scoring for Bank Failure and Connections of New Load

Forecast Questionnaire Scoring for Bank Failure and Connections of New Load		
Response	**Scores for Bank Failure Question (Score for component 1)**	**Scores for Questions Regarding Potential Connections to High Energy Loads and Impact of External Factors (Scores for components 2 - 8)**
High	10	5
Medium	6	3
Low	3	2
None	0	0

The scores for the fourth group, Operational Benefit questions, are based on the equipment being proposed as part of the traditional mitigation project. If more than one piece of equipment is proposed, for example a new bank and feeder, only the equipment with the largest score is used in the evaluation. The scores are shown in Table 4-3 below for Operational Benefit. These scores increase to reflect that some projects (new substations) have built-in flexibility to accommodate load growth that could exceed that which is included in the current forecast.

Table 4-3: Forecast Questionnaire Scoring for Operational Benefit Questions

Forecast Questionnaire Scoring for Operational Benefit Questions (Score for components 9-13)	
Equipment	**Score**
New Substation	10
New Substation Transformer	8
Replaced Substation Transformer	6
New Circuit Breaker	4
New Tie	2

The scores for the individual first 8 components are added together for each CDO along with the single appropriate score for components 9-13 (Operational Benefit). To obtain a measure of certainty for the Joint Prioritization Metrics Workbook Template, these aggregate scores for each CDO are converted to a negative value after they are summed. These summed values are then normalized and used to develop rankings for all of the CDOs which are used in the overall ranking of the projects. The larger negative values represent the projects with the least certainty. The scores range from -12 to -40.

Discussion of PG&E Forecast Questionnaire

- Potential of Bank Failure Question
  - This component seems geared more to capturing the potential for implementing a DER solution in lieu of a transformer bank replacement and then having the transformer fail during the DER contract period resulting in the potential of having to replace the transformer and as a result no longer need the ER solution. This is, in effect an economic risk to ratepayers.
  - Of the nineteen banks proposed to be replaced by a capacity project on the CDO list, 7 were rated as having a high risk of bank failure based on condition, 7 were rated as having a medium risk, and 5 were rated as having a low risk.
  - The risk was based on the oil and dissolved gas scores from the most recent substation transformer test. How the test results were converted into a risk score is unknown.
- Potential Connections of Large Energy Loads Questions
  - This group addresses the potential for new un-forecasted and un-requested new load that if it materialized could potentially result in the DER, if implemented, being too small for the load that ultimately materializes. It includes four types of loads - new EV charging stations, new cannabis cultivation, new agriculture load, and new High-Tech campuses.
  - The likelihood of additional EV charging stations was predicated on a) number of existing EV charging stations/number of new EV applications for service, and b) proximity to attractive EV fast charging locations (highway, especially intersection of two major highways, availability of good lease sites with public amenities, etc.). Scores for other potential loads (cannabis cultivation, new agricultural pumps, and high-tech growth) were based on similar criteria.

- Based upon a review of the summary of the questionnaires included as Appendix G in PG&E's GNA/DDOR Report, each CDO was identified as having the potential of at least one of these large un-forecasted energy loads connected.
- All CDOs in the summary were designated as having the potential for un-forecasted EV charging load to be connected.
- Seventeen of the CDOs in the summary were designated as having the potential for all four types of the un-forecasted loads being connected.
- The scores for this group ranged from 6 to 17.

- Potential for the Impact of External Factors Questions
    - Each CDO was identified to have the potential for impact of at least one external factors (water allocation, temperature sensitivity, or Covid-19 impact).
    - It is not clear how the temperature and water allocation factors (included in the Potential Impact of External Factors) relate to the factors already incorporated in the 1-in-10 forecasts used to determine need that already capture temperature and water allocation impacts.
    - Some CDOs were designated as having the potential impact of all three external factors.
    - The score for this group ranged from 2 to 10.
- Operational Benefit Provided Questions
    - The score for this benefit was based on the type of project proposed to address the need as shown in Table 4-3.
    - Each CDO had a benefit score which ranged from 2 to 10.
    - This group seems to capture the amount of load forecast risk that the proposed project can cover by nature of its design and/or based upon the lumpiness of traditional infrastructure projects.

The Forecast Questionnaire did not have a separate documented set of instructions for planners to use in responding to the questions. However, PG&E indicated that there was a calibration meeting among the planning engineers to discuss the results and make sure questions were answered consistently across the PG&E system.

Few, if any, of the questions in PG&E's questionnaire address the certainty of the forecasted need but rather ask about the potential for additional un-forecasted load to materialize or the ability of the proposed project to accommodate un-forecasted load growth (through margin that comes with the project). In addition, there is a real potential that the two questions (Components 6 and 7) are duplicative to the types of factors considered during the load forecast process itself. They don't appear to provide any new information that should not already be reflected in the load forecast.

Review of SCE Approach

SCE uses a Level of Certainty Questionnaire completed by Planning Engineers to evaluate the certainty of each CDO. It consists of 7 components covering both customer and SCE information regarding the project. Because a single traditional wires solution can be developed to address multiple load growth drivers, the grid need certainty score is the weighted average of the size (MW) and Level of Certainty (LOC) scores of all of the customer projects driving the need for the traditional wire's solution. LOC scores are the output of a matrix used by SCE to quantify the status of the customer projects and installation timelines. The table below illustrates the guidelines used in the LOC matrix to generate the LOC score.

Table 4.4: SCE LOC Matrix Form with Scoring Guidelines

	Score	0	1	2	3	Weight
Customer Information	SCE Application for Service	N/A	Received	N/A	N/A	1
	Construction Status	Not Started	Grading	Construction Started/Existing Building	Construction Complete	3
	High/Low Voltage Switchgear	None	Design/ Drawings Received	Approved	Authority Having Jurisdiction (AHJ) Signoff/Installed On-Site	2
	Load Schedule	None	Range Provided but no firm Values	Received but not validated	Data Confirmed	1
	Status of Environmental Review or other Regulatory efforts	Not Started	In Progress/Not Required	Filed	Approved	1
SCE Information	Added Facilities	None	Customer Moving Forward	N/A	Added Facilities Agreement Complete	2
	Design Status	Not Started	Preliminary Design	Final Design Approved	Customer Invoiced	1

Scores are developed for each project with the highest scores representing the projects with the most certainty.

Discussion of SCE Questionnaire

The SCE questionnaire addresses the issues they deem important to tracking and monitoring new load development that has been requested by their existing and new customers. The questionnaire focuses on the certainty that the forecast load is likely to materialize by examining the various aspects of project development for projects that are driving forecasted load growth that results in needs. This is consistent with the purpose statement provided by SCE listed in the first part of this section.

Review of SDG&E Approach

SD&E uses three components or factors to evaluate the forecast certainty – a weather factor adjustment, a customer specific development, and a historical load comparison to the forecast.

Table 4-5: SDG&E Certainty Matrix

Criteria	Higher Ranking	Lower Ranking
Weather Factor Adjustment	Average weather factor applied compared to overall system	Above-average weather factor applied compared to overall system
Customer-Specific Development	Numerous customer requests for new load	Fewer customer requests for new load
Historical Load	Forecast peak with minimal variation from recent years' peak	Forecast peak with significant variation from recent years' peak

The scores for Weather Factor Adjustment and Historical Load are based on statistical analysis of the past three years of circuit peak loads. The score for Customer-Specific Development is based on the number of customer requests. Scores are assigned on a relative basis, i.e., if there are only two CDOs and one of them has a larger number of customer requests than the other, the CDO with the larger number of customer requests will get a higher Customer-Specific Development score of 2 (the project with fewer customer requests will get a score of 1). Scores are developed for each project with the highest scores representing the most certainty. Scores are developed for each project with the highest scores representing the most certainty.

Discussion of SDG&E Questionnaire

Since SDG&E had only two CDOs, their questionnaire did not have to handle a range of projects. While the questionnaire may have been adequate to rank two projects it will likely have to be modified to be used to rank more CDOs.

4.1.1. Observations, Conclusions, and Recommendations

- We observe that the three utilities use a common Joint Prioritization Workbook Template based upon three Metrics and multiple sub-metrics. The Forecast Certainty Metric has one quantitative sub-metric (Grid Need Certainty) which is used to develop Forecast Certainty Scores which are then used along with the other two Metrics to rank projects into three Tiers. The Grid Need Certainty quantitative sub-metric is driven by responses to a set of questions that are significantly different among the three utilities.
- We observe that SCE's questions are aimed at assessing the likelihood that load growth which is driving need for a project will materialize as forecasted.

- The PG&E focus is to identify the likelihood the load will exceed the forecast and the DER solution will then be insufficient for the final resulting load. The SCE and SDG&E focus is to identify the likelihood the load will not develop, and the DER solution will not be needed.
- We observe that PG&E's questions for the most part do not address the likelihood of forecasted load materializing that drives need. Instead, they address 1) the likelihood that needed assets for DER solutions will fail, 2) the likelihood that the load is driven by external factors, 3) the likelihood that additional un-forecasted load that has not been requested by a customer will materialize, and 4) how much flexibility the proposed traditional project provides to accommodate unanticipated increases in load.
- We observe/recommend that SDG&E's questions:
    - May have the potential to overlap considerations of load forecast temperature sensitivity that is included in the load forecasting process (similar to PG&E).
    - We recommend that in modifying the questionnaire to accommodate more projects, SDG&E should ensure the questions are focused on issues related to load materializing.
- There may be valid reasons why the focus of the IOUs is different. For example, PG&E and SCE have different average circuit load by design, which could be one rationale for differences. <u>We recommend</u> the utilities review and understand why the focus is different and communicate the reason to stakeholders.
- <u>We recommend</u> that the Grid Need Certainty Sub-metric be addressed in a Reform Workshop.
- We observe that the issue of operational flexibility is a real-world issue for those having to operate a distribution system. Utilities have made that point a number of times in the DIDF proceeding. We believe that while it is something of importance, operational flexibility does not logically fit into the Grid Need Certainty Sub-metric.
- <u>We recommend</u> that the issue of system operational flexibility and how it could be impacted by DERs be discussed in a Reform Workshop.

4.2. Use of Flags in the Prioritization of Candidate Deferral Opportunities

The three IOUs used, for the first time, the Joint Prioritization Metrics Workbook Template they jointly developed which was approved by the Energy Division on May 14, 2021. As in prior years, three prioritization metrics – Cost Effectiveness, Forecast Certainty, and Market Assessment were used in the prioritization process and in the final placement of CDOs into Tiers. The use of a standard workbook in this current cycle has been successful in making the process more transparent and more easily understood by stakeholders.

In 2021, some of the sub-metrics which make up the prioritization metrics were changed. Currently each of the three prioritization metrics has two to four sub-metrics for a total of nine. There are five quantitative sub-metrics that are normalized and summed to create an overall score, and four qualitative sub-metrics used to flag CDOs that are unlikely to be successful for DER sourcing as identified by each utility. These four sub-metrics are flagged if the CDO does not meet a specific requirement or threshold. The sum of the five quantitative sub-metric scores determines the relative rank of each CDO. CDOs are tiered, in part, based on their aggregate quartile performance across the three prioritization metrics using the red-amber-green (RAG) score. A RAG score of +1 is assigned to first quartile projects, a 0 to second/third quartile projects, and a -1 to bottom quartile projects across each prioritization metric. Projects with a total RAG score >0 are assigned to Tier 1, projects with a total RAG score equal to 0 are assigned to Tier 2, and projects with a total RAG score <0 are assigned to Tier 3. If one of the four qualitative sub-metrics for a given Prioritization Metric is flagged, the Prioritization Metric itself is also flagged, and the Candidate Deferral Opportunity is automatically placed into Tier 3.

While each IOU used the approved Prioritization Metrics Workbook Template and had the opportunity to use Flags, they were not used consistently by PG&E and SCE as identified in the following table. SDG&E did not adopt any Flag values so there was no way to assess SDG&E's use of Flags.

Table 4.6: Use of Flags by Utility

Use of Flags by Utility				
Metric	Cost Effectiveness	Forecast Certainty	Market Assessment	
Sub-metric	Unit Cost of Traditional Mitigation ($)	Year of Need	Operational Requirement	Number of Grid Needs
PG&E	Less than $1M	2025 or later	Real Time	More than 3
SCE	Did not adopt a flag value	Did not adopt a flag value	Islanding	Did not adopt a flag value
SDG&E	Did not adopt a flag value	Did not adopt a flag value	Did not adopt a flag value	Did not adopt a flag value

4.2.1. Development of Sub-metric Flags

PG&E

Unit cost of Traditional Mitigation Sub-metric - The Cost Effectiveness metrics are intended to provide a relative indication of how likely distributed energy resources (DERs) can cost effectively defer a Planned Investment. Based on PG&E's experience it is difficult for DER to be cost effective against a low-cost wires project. PG&E adopted a Unit Cost of Traditional Mitigation Flag minimum of $1M which effectively eliminates projects whose cost is less than $1M from further consideration by placing it in Tier 3.

Year of Need Sub-metric - the experience of the IOUs indicates projects with need dates further out in the future have less certainty and are likely to be assessed in a future cycle. Based on this, PG&E adopted 2025 as the latest date for a project without flagging the Year of Need Sub-metric. Thus, projects that have need dates in 2026 or later are placed in Tier 3.

Operational Requirements Sub-metric – PG&E's experience is projects requiring real time dispatch are less likely to be sourced via DERs than projects with operational requirements that only require day ahead dispatch. Therefore PG&E adopted a Flag for projects requiring real time dispatch.

Number of Grid Needs Sub-metric - Lessons learned by PG&E from prior RFOs have indicated it can be difficult to source DERs from multiple locations to meet a single Candidate Deferral Opportunity (CDO). Therefore PG&E adopted a Flag for projects that have more than three grid needs.

SCE

Unit Cost of Traditional Mitigation Sub-metric – SCE believes it is very difficult for DER to be cost effective in comparison to a low-cost wires project. However, SCE did not adopt a Flag threshold for SCE's 2021 Prioritization Metrics to be more inclusive with its 2021 candidate deferral projects. SCE plans to develop reasonable Flag thresholds for this sub-metric in the future based on their experience with varying DER deferral costs along with the different procurement mechanisms established in 2021.

Year of Need Sub-metric – Projects with a year of need beyond the established threshold would be assigned to Tier 3 and not be recommended for the competitive solicitation framework. SCE did not adopt a Flag threshold for this sub-metric but will continue to evaluate DER deferral experience with varying project timelines to set a reasonable year of need threshold in the future.

Operational Requirements – SCE's prior competitive solicitation experience has illustrated that DERs are more successful when they are notified day ahead to support distribution reliability needs. Irrespective of its market assessment score, projects with grid needs that require DERs to operate in real time or in an islanded mode have low deferral viability. Therefore, projects that require islanding are flagged by SCE.

Number of Grid Needs – SCE did not adopt a Flag threshold for this sub-metric to be more inclusive with its 2021 candidate deferral projects in the various procurement mechanisms established for 2021. To set future Flag thresholds, SCE will continue to evaluate if a set number of grid needs significantly impacts DER deferral success for specific procurement mechanisms.

SDG&E

Per SDG&E, for the 2021/2022 procurement cycle, when there are less than three CDOs, candidate deferral opportunities are deemed Tier 1 projects unless there are "red flags" associated with a project in which case the project will be deemed Tier 3.

4.2.2. Use of Flags

As expected, the results from Flag usage varied since the intent of the Flags was to give utilities the opportunity to consider their experience in the prioritization process. PG&E assigned a total of 22 Flags to 16 CDOs (six CDOs had two flags) while SCE assigned Flags to only one project and SDG&E did not assign any Flags.

As can be observed from the Table below, the Flags for PG&E split between the Unit Cost of Traditional Mitigation, Operational Requirement, and Number of Grid Needs while SCE had only one Flag for Operational Requirement.

Table 4-7: Usage of Flags by Utility

Usage of Flags by Sub-metric				
Metric	Cost Effectiveness	Forecast Certainty	Market Assessment	
Sub-metric	Unit Cost of Traditional Mitigation ($)	Year of Need	Operational Requirement	Number of Grid Needs
PG&E	8	0	8	6
SCE	0	0	1	0
SDG&E	0	0	0	0

The use of Flags resulted in SCE placing one project into Tier 3 and PG&E moving two projects from Tier 1 into Tier 3 and 10 projects from Tier 2 to Tier 3.

As shown in the Table below, PG&E also had eight CDOs flagged because their Unit Cost of Traditional Mitigation was less than $1M (PG&E's adopted minimum cost for a assigning a Flag for a project). SCE had 2 CDOs and SDG&E had 1 CDO with a Unit Cost of Traditional Mitigation of less than $1M as shown in the Table.

Table 4.8: Summary of CDOs with Unit Cost of Traditional Mitigation of Less Than $1M

Summary of CDOs with Unit Cost of Traditional Mitigation of Less Than $1M			
Utility	Total Number of CDOs	Number of CDOs with Unit Cost of Traditional Mitigation less than $1M	Cost Range for CDOs under $1M

PG&E	44*	8	$95K-$945K
SCE	15	2	$313K and $501K
SCDG&E	2	1	$628K

*After removal of Zamora 1108 CDO. On September 1, 2021, the voltage regulator at Knight's Landing Substation failed resulting in an emergency replacement of the transformer with a transformer with an internal load tap changer. This replacement addressed the need for the Zamora 1108 circuit.

4.2.3. Observations, Conclusions, and Recommendations

- We conclude that the use of the flags contained in the Joint Prioritization Metrics Workbook Template are appropriate indicators to use in the prioritization process.
- As a consequence, 12 of their 44 CDOs resulted in lower Tier ratings than would have been the case without the use of Flags.
- Since this was the first year the Joint Prioritization Metrics Workbook Template was used, it is reasonable for each utility to use Flags differently based upon the individual utility need and experience. However, it appears reasonable that over-time the value of the Flags would ultimately be similar among the utilities.
    - The Cost-Effectiveness sub-metric that is based upon the cost of the planned investment is in large part a function of the cost of implementing DERs which would seem to be similar across the three utilities.
    - The Operational Requirement sub-metric requirement is Real Time for PG&E and SCE. SDG&E did not indicate that they adopted a flag for this sub-metric, but the IPE believes Real Time would likely be a requirement for SDG&E as well.
    - The Number of Grid Needs sub-metric for PG&E was based upon their experience from prior RFOs. SCE plans to review its experience from the various 2021 procurement processes before establishing their Flag. It is reasonable to expect SCE's experience will be similar to PG&E's. SDG&E did not discuss a threshold for the Number of Grid Needs sub-metric.
    - We observe that PG&E's Year of Need Flag places project into Tier 3 if the Year of Need is later than 2025. This is essentially the same as the action of the Timing Screen which screens out projects that have Need Dates beyond 2025.
- <u>We recommend</u> the three utilities share their data and develop threshold values which will be used for each Flag and share them in their GNA/DDOR Report along with the basis for establishing each threshold.
- The current methodology places any CDO with any Flag into Tier 3. As a result, all Flags have the same impact or weight, which is to remove the CDO from further consideration.
    - While the Number of Grid Needs is an indication of the difficulty of meeting all of the needs of a project, we believe it could place a project with very high Cost-Effective ranking into Tier 3. It seems that with a sufficient "budget" the number of grid needs would be less an overriding factor.

  - The Operational Requirement Sub-metric (Real Time or Islanding) on the other hand appears to be a factor that should override the results of the ranking based upon the three metrics.
  - With respect to a Flag for a Unit Cost of Traditional Mitigation it is reasonable to consider a cost threshold in the process.
- We recommend Flags be used to develop the initial prioritization or tiering as they were used in the 2021/2022 cycle, but CDOs with flags be reviewed to ensure an otherwise high priority CDO is not overlooked because of a less impactful Flag. A utility should be able to deviate from automatically placing a CDO with a Flag into Tier 3 after this review based on the utility's judgement.
- We observe that the Workbook seems to define the size of the upper quartile that defines whether a project is given a green score or not in a way that truncates the quartile size. For example, if you had 47 CDOs the Workbook would define the upper quartile as having 11 projects. A fourth of 47 is 11¾. If we round up, the number of projects in the upper quartile would be 12 instead of 11. We recommend consideration of changing from the current implementation to one that rounds the number up to develop the size of the upper quartile.

4.3. Operational Requirements

In this section we review the methodology used by the three utilities to develop the Operational Requirements that are used in the Joint Prioritization Metrics Workbook Template (JPW) and are used as requirements in the solicitation process for projects that proceed to procurement (as a project in an RFO, SOC pilot, or Partnership Pilot. Operational Requirements are broadly defined as:

- Peak Capacity Need
- Peak Day Energy Need (often expressed as an hourly profile)
- Day of the Week Need (usually expressed as Weekday, Weekend, or All Days)
- Numbers of Months of Need (expressed as a list of Months or a season)
- Monthly Number of Events of Need (usually expressed as events or days per month)
- Yearly Number of Events of Need (usually expressed as events or days per year)
- Requires Day Ahead or Real Time Dispatch
- Requires functioning in an Islanded Mode of Operation

The way in which each of these requirements are used in the JPW is described below:

- Peak Capacity Need – This value is used to develop a Cost Effectiveness Sub-Metric in the JPW (the LNBA $/MW-yr metric) and a Market Assessment Metric (Capacity Need (MW/Circuit)).
- Peak Day Energy Need (often expressed as an hourly profile) – This value is used to develop a Cost-Effective metric (LNBA $/MWh-yr) and an informational value requested by the IPE (LNBA $/MWh-day).
- Day of the Week Need (usually expressed as Weekday, Weekend, or All Days) – this value is used in the calculation of the Cost-Effective Metric (LNBA $/MW-yr) specifically to develop

the total number of days per year used to develop the denominator. This applies to PG&E and SDG&E, but not SCE since they use an 8760 methodology.

- Numbers of Months of Need (expressed as a list of Months or a season) – this value is used in the calculation of the Cost-Effective Metric (LNBA $/MWh-yr) specifically to develop the total number of days per year used to develop the denominator. This applies to PG&E and SDG&E, but not SCE since they use an 8760 methodology.
- Monthly Number of Events of Need (usually expressed as events per month) – this value is used in the calculation of the Cost-Effective Metric (LNBA $/MWh-yr) specifically to develop the total number of days per year used to develop the denominator. This applies to PG&E and SDG&E, but not SCE since they use an 8760 methodology.
- Yearly Number of Events of Need (usually expressed as events or days per year) – this is used in the calculation of the Cost-Effective Metric (LNBA $/MWh-yr) specifically to develop the total number of days per year used to develop the denominator.
- Requires Day Ahead or Real Time Dispatch – this is a qualitative flag that is used to place a project into Tier 3 if Real Time Dispatch is required.
- Requires functioning in an Islanded Mode of Operation – this is a qualitative flag that is used to place a project into Tier 3 if operation in an islanded mode is required upon deferral of the CDO.

4.3.1. PG&E Methodology

Operational requirements are developed using 576 load profile data exported from LoadSEER into a PG&E in-house Excel template. The 576-profile data includes loading by month and hour for the peak weekday and weekend day of each month of the year. An hourly profile is developed for the peak weekday and weekend day for each month, identifying the times and magnitude of any overload. According to PG&E, since a weekday could be any weekday in the month, it is assumed for the purposes of determining the maximum calls (or days) per month, the DER could be needed every weekday that month. The same approach is taken for weekend days. Therefore, a need for a DER on one weekday would result in a requirement need of approximately 20+ days per month (depending upon the number of weekdays in the month) and a maximum of approximately 8 days with needs per month (depending upon the number of weekend days per month), if the overload only occurs during a weekend day. In other words, if there is a need in the weekday profile data and the weekend profile data for January 2023, the number of days of need for January is calculated as 21 weekdays in January + 5 weekends X 2 = 31 days.

The hourly profile for the peak day from LoadSeer is used to calculate the hours of need. PG&E establishes the hours of need by taking the hours in the day that have overloads and adding one hour on each side of the overloaded hours.

The annual energy value used in the LNBA MWhr-yr is the product of the number of days of need per year (which is the sum of the monthly needs (i.e., 31 hours in the example above for January)) times the highest peak day energy need in any of the 10 years of the planning period.

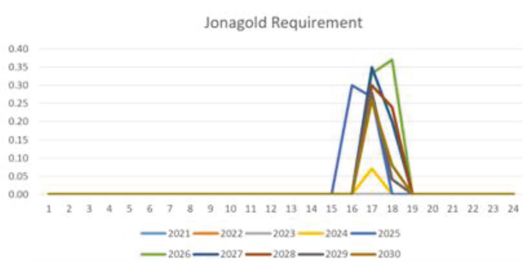
4.3.2. SCE Methodology

SCE uses an 8760 profile to determine the hours of need for each year of the study. Any hour of overload is considered in developing the following operational requirement values:

- Duration which is the value of the maximum number of hours of need on the peak day and is used in the JPW
- Capacity which is the largest need in any hour in the 10-year planning window
- Energy which is the largest energy need on the peak day of the 10-year planning year
- Season which is Summer. Spring and/or Winter or Year-Round with grid needs for each year of the 10-year planning period
- Monthly Frequency is the maximum number of days of need in each month from the 8760 analysis (must be greater than zero) or 5 whichever is larger
- Yearly Frequency is the number of days of need in a year which is the number of the days of needs (must be greater than zero) rounded up to the nearest 5 or 15 whichever is larger.

An example of the results of this methodology is shown in the Figure below.

Figure 4-1: Operational Requirements Associated with Jonagold (From 2021 SCE IPE Report)



Capacity (MW)	Energy Need (MWh)	Season	Monthly Frequency	Yearly Frequency	Year
0.0	0.0	N/A	0	0	2021
0.0	0.0	N/A	0	0	2022
0.0	0.0	N/A	0	0	2023
0.1	0.1	Summer	5	15	2024
0.3	0.6	Summer	5	15	2025
0.4	0.7	Summer	5	15	2026
0.4	0.6	Summer	5	15	2027
0.3	0.5	Summer	5	15	2028
0.3	0.3	Summer	5	15	2029
0.3	0.4	Summer	5	15	2030

	Peak Hourly Need (MW)																							
Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
2021	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2022	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4	0.0	0.0	0.0	0.0	0.0	0.0
2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.2	0.0	0.0	0.0	0.0	0.0	0.0
2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.2	0.0	0.0	0.0	0.0	0.0	0.0
2029	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2030	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0

- A new 12kV circuit at El Casco 115/12kV substation is planned to relieve the Jonagold 12kV circuit, served from El Casco 115/12kV, which is projected to exceed capacity limits.

These values are then used to develop the Metrics in the JPW for Cost Effectiveness (LNBA$/MW-yr, and LNBA$/MWh-year) and for the Market Assessment (Capacity Need (MW)/Circuit).

4.3.3. SDG&E Methodology

The methodology used by SDG&E is similar to the PG&E methodology, in part, because they use the same LoadSEER tools (based upon 576 hours) to support their distribution planning. A summary of that process is shown below:

- First, SDG&E uses the 1-in-10 net load profile for the circuit/bank and its rating to determine the overloads and hours and months during which the overloads occur during the deferral years, i.e., first year of service (2024 or 2025) to 2030.
- SDG&E uses the maximum overload as the Capacity (MW) that is needed from DERs. For example, if the maximum overload occurs in hour 19 in the year 2030, this overload sets the DER capacity requirement for all the overloaded hours in that year.
- The duration for which DER needs to provide this capacity is determined adding an hour before and after to the hours during which there is a forecast overload. For example, if the overload occurs in hour 19 is the year 2025, the duration for which the DER needs to operate is determine as hours 18 through 20.
- The Energy Need (MWh) is determined by multiplying the capacity requirement by the duration. For example, if 0.5 MW is needed for 6 hours, then the energy need is 3 MWh.
- To calculate the annual frequency (i.e., how many times the overload occurs and hence the DER solution could expect to be called to provide NWA service), SDG&E assumes that if there is an overload on either a weekend or weekday of each month, then the overload has the potential to occur in any or all days of the month. For example, if the 576 data shows overload in a typical weekday in July through September, then SDG&E assumes that the frequency of occurrence of the overload is 92 (overload occurs each day in July (31 days), August (31 days) and September (30 days)).
- Since the peaks could occur in the summer months (typically, June through October), the period during which the DER needs to provide the NWA service includes these months.

4.3.4. Observations, Conclusions, and Recommendations

- We observed in our IPE DPAG Report for PG&E that the methodology that extrapolates a single need for one weekday in a month based upon using a single profile into a need in every weekday in that month (approximately 20+) is overly conservative. Such an extrapolation is equivalent in simple terms to saying that the peak load forecasted for the month will occur every weekday of the month. For a circuit whose is temperature sensitive, it is similar to saying we are going to have extreme weather every day during the month. We observe that SDG&E has a similar methodology that assumes that all 30 days are overloaded if either a weekday or a weekend is overloaded which is similarly overly conservative.
- We acknowledge that this methodology does likely identify the number of days that could experience a monthly peak and is therefore useful to identify when a DER has to be available, but it overstates the number of days that the DER is likely to be called upon.
- A simple comparison between the 8760-methodology used by SCE and the 576-hour approach by PG&E and SDG&E may help to make the point.

For the Jonagold circuit shown earlier in Figure 4-1, the monthly need for 2025 is 5 days based upon the SCE methodology. This comes directly from the number of days in each month that an overload is found using the 8760-profile analysis. Based upon SCE's rules the value of 5 was set because the number of days with overloads is less than five. The annual days of needs for 2025 is 15 which appears to be a value that has been rounded up. For this circuit the energy used in the denominator of the LNBA $/MWh-year metric would be a daily energy multiplied by 15.

Using the 576 methodology and assuming the peak occurs only on weekdays (the difference would be larger if it was assumed that it also occurred on the weekends) in the three summer months, the monthly days of need would be 20+ and the yearly need days would be about 61 or roughly 4 times that developed using the 8760 approach. All other things held constant the LNBA $/MWh-yr would be 25% of the value calculated using the 8760-hour approach since the denominator is 4 times larger.

- The difference in these two methodologies has the potential to impact the ranking of projects because they directly affect the two Cost Effectiveness Metrics – LNBA $/MW-yr and LNBA $/MWh-yr. The differences in the results from the two methodologies will vary with, and be most different for, projects with lower number of days of need.
- We recommend for the purpose of developing metrics for the JPW that days of need be estimated that reflect the expected number of days of operation not the number of days that a dispatch might occur in a month. The former is a better gauge of the cost of the DER (since they do not really have to plan to operate 20+ days per month) and thus more useful as a cost effectiveness ranking metric. The latter (number of potential dispatch days) is something that we believe is very important to communicate and include in procurement requirements so that regardless of which day or few days in a month the peak actually occurs, the DER is required to be available for dispatch.

5. Capital Project Review – Step 21

In this section we summarize follow up review that was performed in the 2021/2022 cycle on the results of the 2020/2021 cycle.

5.1. Background

In the 2020/2021 DIDF cycle the IPE Plan for all three utilities included a Step 21 which included a review of the capital projects of utilities to determine if additional types of projects should be included in the DIDF process for consideration for deferral. That work was accomplished in the 2020/2021 DIDF and indicated the current scope of capital projects being considered was complete and no other type of capital work needed to be included, However, the IPE Report recommended examining one type of capital project, the potential for deferring asset replacements by extending their useful life by reducing the loading on the asset.

5.2. Asset Review

The IPE included the review of various types of assets (more than the recommended substation transformer assets included in the IPE DPAG Report) for this type of potential deferral mechanism. The review included OH/UG switches, capacitor banks, remote automatic reclosers, and transformers.[3]

For this type of deferral to work, it would seem[4] the following would be needed, at a minimum:

- An Asset that is scheduled to be replaced on a timeline that is consistent with the DIDF cycle timing – i.e., scheduled for replacement in the 3-5 year timeline window and the schedule would need to be relatively firm/fixed.
- An Asset whose life is a function of the loading on the asset such that its scheduled replacement could be extended a certain amount (number of years) by decreasing the loading on the asset a certain amount (Load Factor). Such life extension would need to be relatively firm/fixed and not change over time, and it would need to be effective at the time an asset is schedule for replacement.
- An Asset that is not likely to have any other factors (other than loading) that would accelerate the need for it be replaced during the original 3–5-year time window plus the length of the DER contract. This time period could easily total 8-10 years.

After an initial review, we concluded that the remaining review would focus on substation transformers as originally recommended in the previous IPE DPAG Report because the remaining

[3] In depth review was performed on the SCE system and the results/conclusions were confirmed with PG&E and SDG&E.
[4] This discussion is theoretical in that it is discussion of a methodology that is not in practice and thus is speculative. Note there could be other ways to implement such a concept.

equipment is not a good match for a number of reasons. One important factor is that the life of these assets is a function of numerous factors as listed below which are unrelated to loading:

- Number of switching operations (load and non-load)
- Corrosion due to coastal or agriculture proximity
- Climate impacts (e.g., hot weather and ice/snow)
- Number of through faults experienced by switch or other equipment
- Oil/gas leaking for submersible switch due to deteriorated seals
- Damaged bushings and weathering (e.g., water damage, exposure to UV light)

In addition, the replacement of this equipment is often driven by the following factors unrelated to loading and thus not something that a DER could mitigate:

- Obsolete equipment
- Standardization of designs, ratings, operating parameters and maintenance practices
- Upgrading ratings and capabilities
- Thermal scanning results finding weakened or damaged components
- Replacement of obsolete equipment (oil)
- Corroded switches may cause a safety issue
- Outdated equipment, lack of control, SCADA, voltage measurements
- Length of time in service
- Number of instances the equipment experienced short circuit duty
- Field or aerial inspection may show conductor abnormalities
- Large number of splices
- Untwisting of strands, resulting in de-rated conductor
- For distribution transformers - chronic oil leaks, overload past its rating limits within a given climate zone, corrosion, degradation, damaged paper insulation that cannot be replaced

5.3. Review of Distribution Substation Transformers

The review then focused on substation transformers.

Some of the main factors that drive ageing and degradation of substation transformers are listed below:

- Time being energized with a voltage potential (independent of loading)
- Serving customer load
- Being overloaded beyond manufacturer specifications
    - Paper insulation on the coils degrading due to heating over time
        - Transformer loading
        - Ambient temperature
- Corrosion due to coastal or agriculture proximity

- Moisture intrusion
- Power system disturbances
  - Lightning
  - Switching
  - Faults

Many of the reasons for replacement of substation transformers are summarized below:

- Results of oil sampling through Dissolved Gas Analysis (DGA)
- Age of assets
- Condition index[5]
- End of planned life of equipment based upon expected life span
- Historical failure analysis[6]
- Technical expert review
- Degradation
- Damaged paper insulation that cannot be replaced
- Obsolete equipment
- Chronic oil leaks

It is acknowledged, however, that loading on transformers is a factor in determining their useful lives.

5.3.1. Observations, Conclusions, and Recommendations

- From the factors listed as drivers for ageing and reasons for replacement it is clear that there are many factors that are not related to loading. These factors cannot be mitigated by reducing loading through the deployment of DERs. Factors unrelated to loading include environmental, deterioration of the asset's condition, age, number of faults/transients, etc.
- The impact of these factors on the life of the transformer asset is not something that a DER can mitigate by reducing loading.
- To be effective in extending the useful life of a substation transformer, reducing loading and the load factor of the asset may have to start early in the life of the transformer before the asset is determined to need to be replaced. Loading reduction is conceptually something that should extend the life of substation transformers, but it is not clear how to understand/estimate such life extension.
- More research/study would be needed to understand if reducing loading over periods of time would result in a predictable number of years of life extension.

[5] Condition index uses statistical analysis to quantify the transformer's condition relative to end of life. This is based on degradation processes such as: insulation, winding, core, bushing, physical condition, tap changers, repair history, and outages.
[6] SCE uses a Weibull curve analysis to estimate the probability that a transformer will fail as a function of its age. Loading is not a variable in the failure analysis.

6. Selection of SOC and Partnership Pilot Projects

In this section we will review the methodology the three utlities used to select, projects to be included in the SOC pilot or Partnership Pilot, and offer recommendations to improve the processes used.

The CPUC established the Standard Offer Contract and Partnership Pilot Pilots to be tried for the first time in the 2021/2022 DIDF cycle. In its decisions it directed the utilities to implement at least one SOC Pilot from Tier 1 and three PP Pilots, with one from Tier 1 and two from Tier 2 and/or Tier 3.

6.1. Common Approaches

The following aspects of the approaches used by the three utilities were the same:

- All started the process of selecting pilot projects using the previously developed candidate deferral list of projects – the result of the timing and technical screen
- All used the Tiering results developed by the Joint Priotization Metric Workbook Template that they used to rank projects
- All appear to have striven to achieve the target number of CDOs for the SOC Pilots and for the Parternship Pilots

The next three section describe where the utlities approaches differed from one another.

6.1.1. SCE Pilot Approach and Results

SCE proposed a transparent numeric algorithm approach to rank candidate as summarized below:

- For the SOC pilots, SCE developed a numerical score based upon the concept of the amount of land available for new DER projects (the SOC is for IFOM projects only) using a number of customers per circuit mile metric for each project in Tier 1. Projects with needs driven by underground circuits temperature violations are removed from the ranking due to SCE's experience that Energy Storage projects are less likely to be cost effective due to charging limitations on underground circuits with temperature violations. The project with the highest ranking of projects in Tier 1 was selected as the SOC pilot project.
- For Partnership Pilots, SCE developed a numerical score based upon projects within Tiers 1, 2 and 3. The numerical score is determined from the relative opportunity of BTM DER integration on each of the projects. The score is a function of the average relief per customer type, the number of customers for each type that can participate on each circuit in the project and the number of customers that are required to meet the project need. Note that in determining the number of customers that could potentially participate, customers with existing PV plus Battery installations and existing demand response customers are not counted.

SCE was successful in selecting a total of four CDOs for the pilots, one SOC and three Partnership Pilot P.

6.1.2. PG&E Pilot Selection Approach and Results

PG&E considered a number of additional factors in their selection process for Partnership Pilot projects as discussed below:

- Candidate Deferral Opportunities that could demonstrate Ratable Procurement (e.g., opportunities with low to moderate capacity needs that have incremental procurement goals).
- Candidate Deferral Opportunities where Ratable Procurement could potentially address the challenge of changing distribution system needs and risk of over- and under-procurement.
- Candidate Deferral Opportunities with grid needs occurring within two to five years of Pilot launch.
- At least one deferral opportunity with a grid need forecast 4 to 5 years out to ensure the subscription period was sufficiently long in duration to test payments.
- Clusters of deferral opportunities and planned investments.
- Planned investments that service Disadvantaged Communities (DACs).

PG&E considered a number of factors in their selection process for SOC pilot projects as discussed below:

- A single Grid Need location to defer the Candidate Deferral Opportunity, in order to facilitate a single Point of Interconnection for an In-Front-of-the-Meter (IFOM) DER solution.
- Indications that there is sufficient capacity at the location of the Grid Need for an IFOM energy storage DER to charge from the grid. PG&E notes that this assessment is only indicative, and the DER solution would still need to pursue the interconnection process.
- Earlier In-Service Dates to test the impact of the SOC pilot on the ability of DERs to meet the In-Service Date.
- Candidate Deferral Opportunities with larger Grid Needs (MW), as those needs may be most appropriate for Utility-Scale IFOM DER solutions.

PG&E ended up selecting a total of seven CDOs to participate in the two pilots – one SOC pilot and six Partnership Pilots which more than met the CPUC requested number of projects to include in the two pilots.

PG&E described the various factors that it considered in selecting projects to participate in the two pilots, but it did not describe how it weighted those factors or otherwise ranked the projects. In other words, to our knowledge, a numerical ranking approach was not used.

6.1.3. SDG&E Pilot Selection Approach and Results

SDG&E's selection approach was constrained by the fact that they had only two candidate deferral projects and thus could not achieve the five pilots requested by the CPUC. The main focus ultimately then was whether to take these two projects to procurement and if so, in which procurement process – the RFO competitive solicitation, the SOC pilot, or the Partnership Pilot?

As discussed in the IPE DPAG Report, we believe that the Joint Prioritization Workbook Template was not necessarily designed to handle ranking and prioritizing two candidate deferral projects. Things like RAG scores and quartiles have no meaning. It appears that SDG&E strove to identify at least one CDO for the Partnership Pilot and one CDO for the SOC pilot to support the CPUC's interest in gaining experience with the two new pilots.

SDG&E selected the CDO for the SOC pilot based upon a review of the number of customers on the circuit. The CDO for the Partnership Pilot was selected because there was more land available based upon satellite-type photography of the geography served by the CDO.

Based upon the result of the first cycle of the SOC pilot (which closed on October 15, 2021), the Energy Division approved SDG&E's plan to submit the same project to a full RFO solicitation which would allow resources on both sides of the meter to participate.

6.1.4. Observations, Conclusions, and Recommendations

- We observe that the three utilities took different approaches to selecting the projects to participate in the first cycle of the SOC pilot and the first cycle of the Partnership Pilot which should provide some additional insight compared to an approach where all took the same approach.
    - PG&E, in particular, selected more than the minimum number of projects requested by the Commission and also chose selected projects and set up payment/procurement to evaluate some different variations - ratable procurement, various timings, etc.
    - SDG&E used a very simple method to select which of its two CDOs would be used for the SOC pilot, and which would be used for the Partnership Pilot.
    - SCE used a numerical score to rank projects for the SOC pilot and for the Partnership Pilot. The numerical scores are based upon a DER adoption model for the Partnership Pilot and available land for the SOC pilot.
- <u>We recommend</u> that for cases where there are multiple CDOs to be considered for the two pilots that some type of numerical scoring be used similar in the concept used by SCEs. In addition, to the numerical scoring, qualitative measures could also be used to further differentiate projects on "secondary" factors similar to PG&E's approach that considered variations to try various combinations of projects (i.e., ratable procurement, timing, size etc.).

7. Miscellaneous Review Results

7.1. Back-tie Projects on the DIDF

In this section we review how the three utilities consider Reliability (back-tie) projects in their Distribution Planning Processes relative to the DIDF.

Reliability (back-tie) services are defined as load-modifying or supply service capable of improving local distribution reliability and/or resiliency. Specifically, this service provides a fast reconnection and availability of excess reserves to reduce demand when restoring customers during abnormal configuration.

In a traditional wires solution, a back-tie, often also called circuit tie or just tie, is normally an open connection between two different circuits. During emergency conditions, a back-tie allows for transfers of load from one circuit to another that result in circuit loading values (after transfers) that are below circuit relay minimum trip settings, emergency cable/conductor capacity limits, component ratings, and emergency duct bank temperature limits. Back-ties can be used to help restore service following the loss of a bank, a circuit or a line section.

A review of distribution planning guidelines performed in the 2019/2020 DIDF cycle of the three California IOUs revealed PG&E and SCE had written guidelines associated with back-ties, and SDG&E did not. Generally, both PG&E and SCE guidelines indicate three ties to adjacent circuits normally provide adequate circuit interconnections and emergency capability to allow load transfers from a faulted circuit. There are exceptions for rural or sparsely loaded areas. Based on feedback from SCE and PG&E, back-tie requirements are identified in their planning process (for example, cases where the transfer over three ties is not sufficient to restore power to a tripped circuit) and these back-tie projects are prioritized and implemented based on level of need and budget availability. Both indicated that due to budget limitations they normally are not available to address all circuits that fail to meet the three transfer criteria.

Based on feedback from SDG&E, back-tie projects are identified in SDG&E's internal planning processes and are prioritized and implemented based on need and budget availability.

While SDG&E does not have written guidelines, they do include some back-ties in their 2021/2022 DDOR as discussed below.

7.2. Back-tie CDOs in 2021/2022

PG&E – While PG&E did identify 19 reliability projects in the DDOR, none of the projects were back-tie projects and none became CDOs because they did not meet the technical or timing screening requirements. Note that PG&E's reliability investment plans in their DDOR includes work such as reconductoring for emergency capability, reducing the normal load on a circuit to not exceed 600 amps and reducing the number of customers on a circuit to less than 6000 customers. PG&E

prioritizes emergency deficiency plans, which includes back-ties, on a system wide basis based on budget and reliability improvement needs.

SCE – SCE identified three Tier 2 sub-transmission CDOs with Reliability, Capacity needs. But none of them were considered as a back-tie need. SCE considers the Reliability Service as providing capacity and/or voltage support during outage conditions such that grid configuration allows customers to continue to be reliably and safely energized from SCE's distribution grid. Under Normal – 1 (N-1) outage conditions, grid needs may require either capacity or voltage support. These planned investments will have one distribution service as reliability and another distribution service as either capacity or voltage listed in the DDOR to distinguish them from the capacity or voltage services provided for normal system conditions.

When studying distribution back-tie needs in 2020, SCE indicated they generally looked at circuits with poor performance or circuits with low number of back-ties due to geography and decided on a case-by-case basis any additional ties they would recommend be installed. In general, back-ties (which are N-1 driven) are prioritized below capacity projects (which are N-0 driven) and are implemented as budgets allow.

SDG&E – SDG&E uses the words "Peak Thermal" to represent "Distribution Capacity" service and "back-tie" to represent the "Reliability (back-tie)" service. In the 2021 DDOR, SDG&E has two CDOs, one of which is a project with Distribution Capacity and back-tie needs and one with just a Distribution Capacity need. It is our understanding that SDG&E does not perform (N-1) outage analysis of its system to explicitly determine the need for back-tie capability in developing projects for the DDOR. Rather, SDG&E's back-tie project reflects their position that traditional wires projects that resolve thermal constraints on SDG&E's system typically also provide back-tie capacity (except for remote radial circuits with no ties). As such, several planned projects in the DDOR that provide capacity are also listed as having a back-tie need.

7.2.1. Observations, Conclusions, and Recommendations

- PG&E and SCE have a documented back-tie planning criteria that is used to determine the need for back-ties. Implementation of back-ties for these companies is based upon demonstrated need (based upon N-1 analysis) and sufficient budget.
- SDG&E differs from SCE and PG&E in that it appears that SDG&E does not have a documented planning criteria used to determine if there is a need for a back-tie.
- SDG&E is the only utility with back-tie needs listed in the DIDF DDOR planned investments. The back-tie is associated with a Distribution Capacity project. The need for the capacity work is clear – which is to meet an N-0 projected overload. The basis for the back-tie need appears to be associated with SDG&E's position that a project that is addressing a thermal need also provides back-tie capacity and therefore a DER alternative needs to provide that back-tie capacity as well.
- We recommend utilities proposing back-tie projects in the DDOR describe the process and analysis used to determine the back-tie need including the specific criteria applied to determine the back-tie need.

7.3. Response to Public Advocates DPAG Question

In this section we respond to a question that was directed to the IPE as part of the 2021/2022 DPAG process.

7.3.1. Public Advocates Office Question related to Alberhill Substation Project

The text of Question Number 3 (from letter of September 24, 2021) is included within the quotation marks below:

"As stated in the IPE report for SCE's 2019 GNA/DDOR report, the IPE should continue its work in determining whether the needs of the Alberhill System Project can be separated to facilitate consideration in the Distribution Investment Deferral Framework (DIDF) and whether the overall cost of the segregated project provides a lesser overall cost to the ratepayer compared to the combined project. In the 2019 SCE DPAG follow-up webinar, SCE ranked the Alberhill System Project as a top-ranked project for deferral.

The IPE notes that "based solely on the three quantitative prioritization metrics, the Alberhill System Project would be a logical choice for Tier 1 consideration since it has the highest Overall Score, the highest Cost Effectiveness score and good scores in the other two metrics." In the 2020 GNA/ DDOR Report, SCE ranked the ASP as a top candidate for deferral; however, SCE states that separating the costs and components of the ASP is not feasible due to the project being designed as an integrated solution. In SCE's 2021 GNA/ DDOR report, SCE ranks the ASP as the top-ranked candidate for deferral but relegates the ASP to Tier 3 because of a flag on the Market Assessment metric. The consistent high ranking of the ASP over the past three DIDF cycles merit further consideration for the ASP within the DIDF process."

7.3.2. IPE Discussion

We note that the formal proceeding for Alberhill is ongoing. However, further discussion with SCE about a capacity-only project concept could help improve understanding of the complexities of a project designed to serve capacity, reliability, and resiliency needs. We recommend that SCE explore the potential for analysis of a capacity-only project designed to serve the Alberhill System Project capacity need in order to facilitate discussions with stakeholders in the 2022/2023 GNA/DDOR process.

8. DIDF Reform Items

8.1. Relative Comparison of Candidate Deferral Opportunities

Background

The Joint Prioritization Methodology includes three metrics and a number of sub-metrics. The three metrics, namely Cost-Effectiveness (CE), Forecast Certainty (FC) and Market Assessment (MA) are used to rank and tier projects and to determine which projects should be considered for deferral through an RFO competitive solicitation, Standard Offer Contract (SOC) pilot or Partnership Pilot. The three metrics are used to rank projects on a relative basis – relative to the pool of candidate deferral project opportunities (CDOs) that made it through the screening process in each cycle. GPI has suggested in its reform comments that the Commission consider moving to an absolute ranking approach for each of the three metrics or a threshold value for a combined project score from the three metrics that would carry over each year.[7] It was suggested that doing so would avoid, for example, taking too few projects to procurement in years where there were many projects (more than a quartile number of them) that would likely be cost-effectively deferred by DERs. In the May 2020 Ruling, the Commission addressed one reform of the Distribution Investment Deferral Framework (DIDF) process, Reform 32 related to the ranking of projects based on absolute value. In this section, the IPE provides some discussion regarding the use of an absolute threshold in the project prioritization methodology. The discussion in this section covers absolute ranking for all three prioritization metrics with emphasis on the cost effectiveness metric.

Existing Joint Prioritization Methodology (A Review)

The Joint Prioritization Metrics Workbook Template places CDOs into three tiers based on a step-by-step process, as illustrated in Figure 8-1.

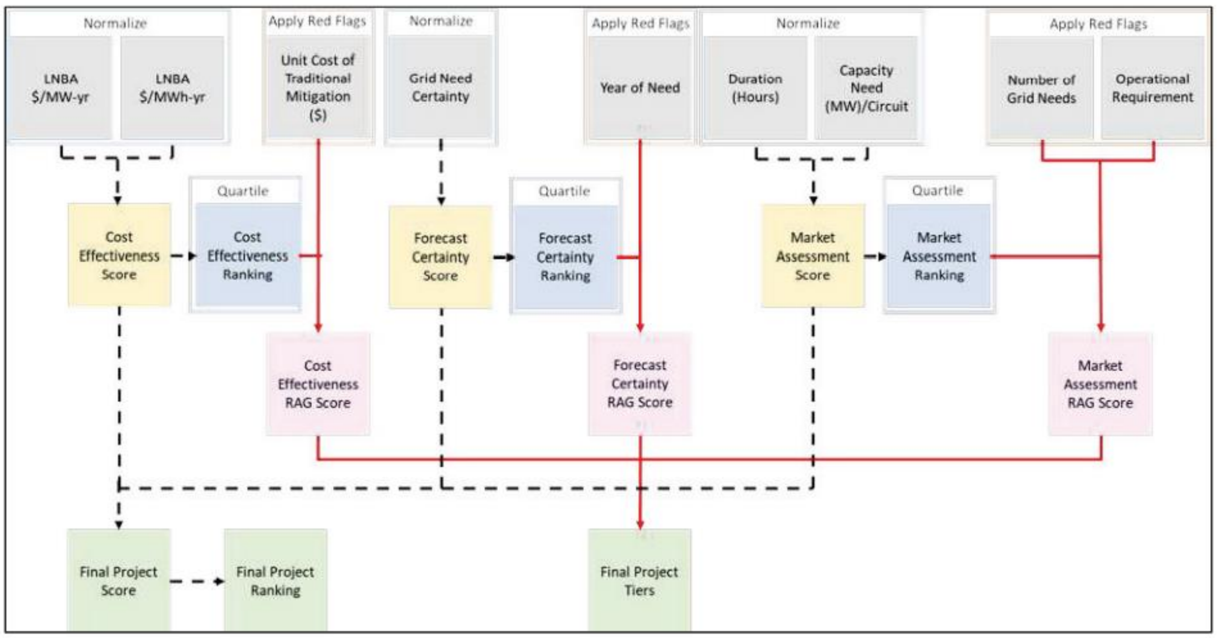
The development of the three-prioritization metrics in the template is based on the evaluation of the sub-metrics of each of the three metrics. Each metric has two to four sub-metrics for a total of nine sub-metrics. Five of the sub-metrics are normalized and used in ranking into tiers and four are flagged if they don't meet a minimum requirement or threshold. The five quantitative sub-metrics are normalized first (based on the maximum and minimum values for each sub-metric). The normalized values for each sub-metric are summed to create a score for each of the three Prioritization Metrics.

Each of the projects is placed into one of four quartiles based upon their three Prioritization Metric scores. Thus, each project's scores are placed into a quartile for Cost Effectiveness (CE), Forecast Certainty (FC) and Market Assessment (MA). Project scores in the top quartile of Prioritization Metric scores are assigned a RAG score of "1", scores in the middle two quartiles are assigned a RAG score of "0", and scores in the bottom quartile assigned a RAG score of "-1".

[7] Page 52 of the 2020 May ALJ Ruling.

The total RAG score for each Candidate Deferral Opportunity is then summed across the three Prioritization Metrics. Those with a total RAG score greater than zero are placed in Tier 1; those with a total RAG score of zero are placed into Tier 2; and those with a total RAG score less than zero are placed into Tier 3. As the total score is summed across the three Prioritization Metrics, a CDO can be assigned a "-1" for one of the Prioritization Metrics (e.g., Forecast Certainty) and still be placed into Tier 1. However, if any of the sub-metrics have one of the five flags set, the Candidate Deferral Opportunity will automatically be placed into Tier 3.

Figure 8-1: Prioritization Metrics, Final Scoring, and Tiering



The Cost-Effectiveness metric is intended to provide a relative indication of how likely DER resources can cost effectively defer a planned investment. This metric has two quantitative sub-metrics, Estimated LNBA $/MW-yr and Estimated LNBA $/MWh-yr. The LNBA-related metrics are developed by taking the LNBA value for the project and dividing that value by the maximum MW need during the deferral period and the maximum MWh-yr need during any one year within the deferral period. For the metric evaluation, these two sub-metrics are normalized and added together. There is also one qualitative sub-metric, namely, Cost of Traditional Mitigation, which is flagged if the cost is less than a threshold value set by each utility.

Reforms Related to Absolute Ranking in the May 2020 Ruling

In the May 2020 Ruling, the Commission addressed several reforms delated to the Distribution Investment Deferral Framework (DIDF) process, one of which was Reform 32 which is related to the ranking of projects based on absolute value instead of the relative ranking. A summary of the reform is provided below.

- Reform 32: In their recommendations for potential 2021-2022 DIDF cycle reforms, the IOUs shall consider GPI's comments about prioritization changing from a relative ranking among the candidate deferral projects identified each year to a ranking based on baseline/absolute threshold values that would carry over each year.

Concepts for Using Absolute Ranking for Cost Effectiveness

In this section, we discuss conceptual approaches on how an absolute ranking approach for Cost Effectiveness might be developed. A discussion of using an absolute ranking approach for the other two metrics is included later in the section.

The approaches discussed are conceptual in nature and would need considerable effort to refine and test to determine how effective they might be in practice. As mentioned earlier, while this discussion covers absolute ranking for all three metrics, there is more emphasis placed on the CE metric since it's a key metric used for determining the viability of DER projects and is already calculated using a standardized methodology followed by all three utilities.

In general, the concept is to develop a threshold value (or values) that can be used to determine if a project's cost-effectiveness metrics exceed the threshold value and are therefore likely to be deferrable by DERs. The threshold value(s) could be developed in at least two ways:

1. Using DER offer data from prior solicitations
2. Using cost estimates of DER solutions for each project

Using the first option, the offer data should reflect the net cost to the developer to put in place a DER solution as well as reflecting any additional income revenue streams. Some form of statistical analysis would need to be used to develop the threshold value with due consideration of the fact that there are two sub-metrics for CE - one based upon MW and the other on MWh.

The second method would be based upon a cost estimate for each project. The method could be a simple mechanism that is based upon the MW and MWh of the need used in a formula that reflects current unit prices for DER solutions (e.g., battery solutions) or a more accurate bottom-up cost estimate. This method of estimating a threshold value would require adjusting the cost value for any additional revenue stream that would be available to the DER project. Without this adjustment, the cost-based threshold value would miss projects that otherwise would be potentially cost effective.

The idea behind the use of the CE threshold is that projects that have CE metric that is equal to or above the threshold should get a score of 1 and project below, a score of 0. With this approach, the cost effectiveness is no longer solely determined using a relative ranking approach, rather based on also using an absolute value. The development of the CE threshold and its use in the existing joint prioritization methodology is discussed below. The discussion below focuses on the first option, using an offer-based threshold.

Development of an Absolute Cost Effectiveness (CE) Threshold

- The CE threshold would be developed based on offer information from prior solicitations. This would require the IOUs to maintain a database of offers received from prior solicitations.
- Based on the information gathered for each offer, an implied per unit cost would need to be developed in $/MW-yr and $/MWh-yr. The same assumptions (interest rate, etc.) used in the LNBA calculations would be used to develop these per unit costs.
- Based on the above, the threshold for the per unit cost would be determined both in terms of $/MW-yr and $/MWh-yr. The minimum threshold could be set to the minimum per unit implied cost calculated from prior solicitations or a multiple of this cost (e.g., 110% of the implied cost) to be conservative. For energy constrained resources, the per unit cost expressed in $/MWh-yr would be most useful. For resources that are not energy constrained, the per unit cost expressed in $/MW-yr would be most useful.
- The key idea is to develop minimum threshold values in terms of $/MW-yr and $/MWh-yr that can be directly compared with the CE sub-metrics (Estimated LNBA $/MW-yr and Estimated LNBA $/MWh-yr) on an apples-to-apples basis.

Using Absolute CE Threshold in the Existing Joint Prioritization Methodology

In this section we discuss conceptually how the absolute CE ranking might work by including the absolute CE threshold in the current joint prioritization methodology with an objective of minimizing the impact of the changes on the existing process.

- The IOUs would use the existing joint prioritization methodology to rank and place the projects in Tier 1, 2, and 3. This process would remain unchanged. The results would represent the result that are arrived at with a relative CE ranking approach.
- For projects that are placed In Tier 2 and Tier 3, their LNBA metric values would be compared to the offer-based threshold values and any project whose LNBA metrics exceeded (were greater/more cost-effective than) the appropriate CE threshold value, the CE score would be set to +1 (if it were not already +1). Projects that are above the absolute threshold value for $/MW-yr or $/MWh-yr would get a score of +1 and the remaining projects scores would initially be unchanged. Once experience is gained with the absolute CE Ranking method, the remaining scores could be set to 0 if the project LNBA metrics were worse than the calculated offer-based threshold value.
- The Total RAG score (i.e., sum of CE, FC and MA sores) would be recalculated. Projects that have a score greater than zero would now be moved to Tier 1.

Discussion Regarding Absolute Ranking for Forecast Certainty and Market Assessment Metrics

As mentioned previously, all three utilities use a standardized methodology (based on the LNBA calculator) to develop the components of the CE metric. This would allow for the use of CE absolute ranking to be based upon three sets of thresholds (one per utility) or one set of thresholds used by all three. We believe the latter may be what GPI was envisioning but the former could be used during a trial period.

There is no standardization among the three utilities in the development of the Forecast Certainty metric. The three IOUs employ different quantitative sub-metrics in the development of the Forecast Certainty metric. For example, PG&E develops a grid need certainty score which is the basis for the Forecast Certainty Metric, which is based on a survey of 13 questions, typically with three potential responses (high, medium, and low). These responses are converted to a score based on a 10-point scale for some questions and a 5-point scale for others. The net grid need certainty score is the sum of the scores of the individual responses.

SDG&E, on the other hand, uses three components or factors to develop a grid need certainty score– a weather factor adjustment, a customer specific development, and a historical load comparison to the forecast. The score for Weather Factor Adjustment and Historical Load are based on statistical analysis of the past three years of circuit peak loads. The score for Customer-Specific Development is based on the number of customer requests. Detailed information on the calculation of the Forecast Certainty metric can be found in Section 4.1.

The range of approaches used by the three utilities makes it difficult to develop a Forecast Certainty (FC) absolute ranking methodology that could be used for all three utilities (one threshold for all three utilities). We have suggested improvements to the methodology used by the utilities to develop grid need certainty scores and it is possible that some utilities methodology may change. Conceptually, each utility could use its improved methodology as the basis for implementing an absolute FC ranking methodology. It could work in a fashion similar to the CE threshold discussed earlier.

The Market Assessment metric is based on two simple quantitative inputs – duration of the need and the amount of need in MW per circuit. This metric is used for assessing the market for a DER solution – needs with smaller duration and capacity need per circuit are assigned a higher rank compared to those with longer duration and higher capacity need per circuit. The utilities may be able to gather data from prior solicitations to determine the threshold for duration and capacity (or capacity as a percentage of the circuit rating) that could be used for absolute ranking of the MA metric.

8.1.1. Observations, Conclusions, and Recommendations

- We discuss in some detail a potential conceptual approach to using an absolute CE ranking methodology. We also discuss (in less detail) applying a similar approach to the FC and MA metrics and what considerations exist for these two metrics.
- We observe that it is just a concept at this point and much work would need to be done to determine if it is workable. We observe that to put something like this in place would most likely take 2 -3 cycles after the decision is made to attempt it. This time would be required to finalize the approach, develop the necessary data, use it one year as a trial and if successful use it in practice.
- We believe that an absolute ranking approach for the CE metric may be easier to develop because of the standardization already in place and we believe using such an approach for the CE metric would be the most valuable of the three metrics given its importance in our view. Thus, one approach may be to develop absolute ranking over time with the initial focus on the CE metric.
- We recommend that stakeholders provide their comments on the options identified in this discussion and the overall approach as well as other alternative approaches.
- We observe that based upon Reform #41, the three utilities are submitting a procurement summary report every six months.[8] If it is determined that more insight into an offer-based approach is desirable as part of implementing an absolute ranking for CE in the future, one option is that the above-mentioned report could be expanded to include offer data (subject to applicable confidentiality provisions).

[8] Every six months IOUs shall submit to ED a DIDF Procurement Status Report noting the status of all DIDF contracts (RFO, SOC, Partnership Pilot), expected Date of Service, any modifications made to any contracts under the DIDF. The report shall include clear tables with current DIDF contract data as well as DIDF contract data from every DIDF cycle to date (including the prior IDER Pilots). A public version shall be shared with the DPAG and a confidential version with Energy Division.

9. Summary of Recommendations

9.1. Section 3.3 – Treatment of Known Loads

The IPE makes the following observations and recommendations regarding the methodology used by the three utilities in the treatment of known load projects in the GNA.

- We observe that SCE uses both embedded and incremental known load growth projects in their GNA which resulted in load growth that exceeds CEC IEPR load growth in some early years and over the 10-year planning horizon. PG&E and SDG&E use known load projects in their GNA that are accounted for in the CEC IEPR over the 10-year planning period but exceed the annual CEC values in the early years.
- We recommend that an approach similar to what is being employed by SCE be considered by PG&E and SDG&E. This includes the utilities' coordinating with the CEC and the CEC accounting/agreeing with incremental known load projects. This approach will result in all three utilities using the same process to reflect embedded and incremental loads.
- One other area that we recommend should be considered is whether the embedded and incremental known loads are discounted in some fashion similar to PG&E's approach to reflect that some customer requests may be delayed, reduced, or cancelled.
- Given the importance of how known loads are implemented in the future, especially incremental loads, we recommend that in addition to maintaining up-to-date known load project databases and sharing them with the CEC, the IOUs report data sufficient for someone to track whether specific known load projects materialize (e.g., unique project identifier, impacted circuit, initial service request date, load amount, and expected online date). The data to track should be selected as appropriate to facilitate an annual review.
- In addition, we recommend that the utilities include a detailed review of their use of embedded and incremental known loads in their GNA/DDOR filings including but not limited to types of loads, number, amounts, timing, summary of embedded and incremental loads, etc.
- We recommend that the utilities collaborate (or continue to collaborate) with the CEC on improving the IEPR forecasts by exchanging information on modelling and assumptions used in the utilities and the CEC's their respective load forecasts.
- We recommend that the utilities document how they handle known load projects related to transport electrification. In particular, whether these transport electrification-related loads are modeled as known load projects or explicitly as EV loads.

9.2. Section 4.1.1 – Forecast Certainty Metric

The IPE makes the following observations and recommendations regarding the methodology used by the three utilities in developing the Forecast Certainty Metric.

- We observe that the three utilities use a common Joint Prioritization Workbook Template based upon three Metrics and multiple sub-metrics. The Forecast Certainty Metric has one quantitative sub-metric (Grid Need Certainty) which is used to develop Forecast Certainty Scores, which are then used along with the other two Metrics to rank projects into three Tiers. The Grid Need Certainty quantitative sub-metric is driven by responses to a set of questions that are significantly different among the three utilities.

- We observe that SCE's questions are aimed at assessing the likelihood that load growth, which is driving need for a project, will materialize as forecasted. We observe that PG&E's questions' focus is to identify the likelihood the load will exceed the forecast and the DER solution will then be insufficient for the final resulting load. The SCE and SDG&E focus is to identify the likelihood the load will not develop, and, as a result, the DER solution will not be needed.
- We observe that PG&E's questions, for the most part, address areas other than the likelihood of forecasted load materializing. Instead, they address 1) the likelihood that needed assets for DER solutions will fail, 2) the likelihood that the load is driven by external factors, 3) the likelihood that additional un-forecasted load that has not been requested by a customer will materialize, and 4) how much flexibility the proposed traditional project provides to accommodate unanticipated increases in load.
- We observe that there is the potential for overlap of load forecast temperature sensitivity that is already included in the load forecasting process (for PG&E and SDG&E).
- <u>We recommend</u> that in modifying the questionnaire to accommodate more projects, SDG&E ensures the questions are focused on issues related to load materializing.
- There may be valid reasons why the focus of the IOUs is different, especially PG&E and SCE, for example they have different average circuit load. We recommend the utilities review and understand why the focus is different and communicate the reason to stakeholders.
- <u>We recommend</u> that the Grid Need Certainty Sub-metric be discussed in a Reform Workshop.
- We observe that the issue of operational flexibility (included in PG&E's methodology) is a real-world issue for those having to operate a distribution system. We believe that while it is something of importance, operational flexibility does not logically fit into the Grid Need Certainty Sub-metric. We recommend that the issue of system operational flexibility and how it could be considered be discussed in a Reform Workshop.

9.3. Section 4.2.3 - Use of Flags in the Prioritization of Candidate Deferral Opportunities

The IPE makes the following observations and recommendations regarding the use of Flags by the three utilities in the prioritization process.

- <u>We recommend</u> the three utilities share their data and develop threshold values which will be used for each Flag and share them in their GNA/DDOR Report along with the basis for establishing each threshold.
- The current methodology places any CDO with any Flag into Tier 3. As a result, all Flags have the same impact or weight, which is to remove the CDO from further consideration.
    - While the Number of Grid Needs is an indication of the difficulty of meeting all of the needs of a project, we believe it could place a project with very high Cost-Effective

ranking into Tier 3. It seems that with a sufficient "budget" the number of grid needs would be less an overriding factor.
  - The Operational Requirement Sub-metric (Real Time or Islanding) on the other hand appears to be a factor that should override the results of the ranking based upon the three metrics.
  - With respect to a Flag for a Unit Cost of Traditional Mitigation it is reasonable to consider a cost threshold in the process.
- We recommend Flags be used to develop the initial prioritization, or tiering, as they were used in the 2021/2022 cycle, but CDOs with flags be reviewed to ensure an otherwise high priority CDO is not overlooked because of a less impactful Flag. A utility should be able to deviate from automatically placing a CDO with a Flag into Tier 3 after this review based on the utility's judgement.
- We observe that the Workbook seems to define the size of the upper quartile that defines whether a project is given a green score or not in a way that truncates the fractional portion of the quartile size. For example, if you had 47 CDOs the Workbook would define the upper quartile as having 11 projects. A fourth of 47 is 11¾. If we round up, the number of projects in the upper quartile would be 12 instead of 11. We recommend consideration of changing from the current implementation to one that rounds the number up (if the fraction is equal to or greater than ½) to develop the size of the upper quartile.

9.4. Section 4.3.4 – Operational Requirements Used in Prioritization

The IPE makes the following observations and recommendation regarding the development of operational requirements used in CDO prioritization.

- We observed the PG&E methodology that extrapolates a single need for one weekday in a month based upon using a single profile into a need in every weekday in that month (approximately 20+) is overly conservative. We observe that SDG&E has a similar methodology that assumes that all 30 days are overloaded if either a weekday or a weekend is overloaded.
- We acknowledge that this methodology does likely identify the number of days that could experience a monthly peak and is therefore useful to identify when a DER has to be available, but it overstates the number of days that the DER is likely to be called upon which has the potential to impact prioritization of CDOs. The difference in these two methodologies has the potential to impact the ranking of projects because they directly affect the two Cost Effectiveness Metrics – LNBA \$/MW-yr and LNBA \$/MWh-yr.
- We recommend, for the purpose of developing metrics for the prioritization process, that days of need be estimated that reflect the expected number of days of operation, and not the number of days that a dispatch might occur in a month. The former is a better gauge of the cost of the DER (since they do not really have to plan to operate 20+ days per month) and thus more useful as a cost effectiveness ranking metric.

9.5. Section 6.1.4 - Selection of SOC and Partnership Pilot Projects

The IPE makes the following observations and recommendation regarding the selection of CDOs for the SOC pilot of the Partnership Pilot.

- We observe that the three utilities took different approaches to selecting the projects, to participate in the first cycle of the SOC pilot and the first cycle of the Partnership Pilot, which should provide some additional insight compared to an approach where all took the same approach.
  - PG&E, in particular, selected more than the minimum number of projects requested by the Commission and also chose selected projects and set up payment/procurement to try out some different variations - ratable procurement, various timings, etc.
  - SDG&E used a very simple method to select which of its two CDOs would be used for the SOC pilot, and which would be used for the Partnership Pilot.
  - SCE used a numerical score to rank projects for the SOC pilot and for the Partnership Pilot. The numerical scores are based upon a DER adoption model for the Partnership Pilot and available land for the SOC pilot.
- <u>We recommend</u>, that for cases where there are multiple CDOs to be considered for the two pilots, that some type of numerical scoring be used similar in the concept used by SCEs approach. In addition, to the numerical scoring, qualitative measures could also be used to further differentiate projects on “secondary” factors similar to PG&E’s approach that considered variations to try various combinations of projects (i.e., ratable procurement, timing, size etc.).

9.6. Section 7.2.1 – Back-ties

The IPE makes the following observations and recommendation regarding the development of back-ties in the GNA/DDOR process.

- PG&E and SCE have a documented back-tie planning criteria that is used to determine the need for back-ties. Implementation of back-ties for these companies is based upon demonstrated need (based upon N-1 analysis) and sufficient budget.
- SDG&E differs from SCE and PG&E in that it appears that SDG&E does not have a documented planning criteria used to determine if there is a need for a back-tie.
- <u>We recommend</u> utilities proposing back-tie needs or projects in the DDOR describe the process and analysis used to determine the back-tie need, including the specific criteria applied to determine the back-tie need.

9.7. Section 7.3.1 - Public Advocates Office Question related to Alberhill Substation Project

In response to the PAO Question Number 3 in their letter of September 24, 2021 regarding the Alberhill Substation Project we have the following recommendation.

- We note that the formal proceeding for Alberhill is ongoing. However, further discussion with SCE about a capacity-only project concept could help improve understanding of the complexities of a project designed to serve capacity, reliability, and resiliency needs. We recommend that SCE explore the potential for analysis of a capacity-only project designed to serve the Alberhill System Project capacity need in order to facilitate discussions with stakeholders in the 2022/2023 GNA/DDOR process.

9.8. Section 8.1.1.- Absolute Comparison of Candidate Deferral Opportunities

The IPE makes the following observations and recommendation regarding the development and use of an absolute ranking methodology in the CDO prioritization process.

- We reviewed in some detail a potential conceptual approach to using an absolute Cost Effectiveness (CE) ranking methodology. We also discussed (in less detail) applying a similar approach to the Forecast Certainty (FC) and Market Assessment (MA) metrics and what considerations exist for these two metrics.
- We observe that it is just a concept at this point and much work would need to be done to determine if it is workable. We observe that to implement something like this would most likely take 2 -3 cycles after the decision is made to attempt it. This time would be required to finalize the approach, develop the necessary data, use it one year as a trial and if successful use it in practice.
- We believe that an absolute ranking approach for the CE metric may be easier to develop than for the FC or MA because of the standardization already in place. We also believe using such an approach for the CE metric would be the most valuable of the three metrics given its importance in our view. Thus, one approach may be to develop absolute ranking over time with the initial focus on the CE metric.
- We recommend that stakeholders provide their comments on the options identified in this discussion and the overall approach, as well as other alternative approaches.

Appendix A IPE Scope (Excerpts from CPUC April 13, 2020 Ruling)

R.14-08-013, A.15-07-005, *et al.* ALJ/RIM/nd3

Attachment A
Listing of Schedule and IPE-Specific Reforms for the 2020-2021 DIDF Cycle

1. IPE-specific reforms for the 2020-2021 DIDF Cycle are implemented within the IPE Scope of Work presented in Attachment B.
2. IOU contracts with the IPE for the full scope of work identified in Attachment B shall be executed by the IOUs to allow for IPE Plan development to begin as soon as possible, ideally on or before **April 17, 2020**.
3. The IOUs shall work with the IPE and Energy Division to develop IPE Plans specific to each IOU such that the IPE can submit the Draft IPE Plans to Energy Division for review on or before **May 15, 2020**.
4. The IPE scope of work may be modified by Energy Division as needed for the IPE to successfully complete each assignment. The IOUs will promptly submit a Tier 1 Advice Letter to notice changes in scope should a scope change differ significantly from the scope described in Attachment B. Minor changes should not necessitate an Advice Letter filing.
5. As required by Energy Division on an annual basis, Pre-DPAG and Post-DPAG activities may include workshops; new, re-opened, suspended, or modified working groups (e.g., Distribution Forecast Working Group); and IOU presentations and deliverables.
6. During the Post-DPAG period and in consultation with the IPE, Energy Division may identify exemplary GNA/DDOR documentation components, analytical approaches, or data strategies implemented by one or more IOUs and require that each IOU implement the reform in future DIDF cycles.

(end of Attachment A)

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R.14-08-013, A.15-07-005, *et al.* ALJ/RIM/nd3

Attachment B
IPE Scope of Work for DIDF Implementation

Term

- January 1st each year to July 31st the following year with the term subject to update by Energy Division if needed to support each DIDF cycle.

Pre-DPAG Period

- Develop an ***IPE Plan*** for each IOU describing the GNA/DDOR review process and detailed approach to Verification and Validation of all data used by the IOUs to prepare their DIDF filing materials.
  - Verification and Validation will include a thorough investigation of the following IOU processes, among others:
    - Collecting circuit loadings and performing weather adjustments;
    - Determining load and DER annual growth on the system level;
    - Disaggregating load and DER annual growth to the circuit level;
    - Checking sum of all disaggregated load and DERs against system-level values;
    - Adding incremental known loads to circuit level forecasts;
    - Developing load, DER, and net load profiles and determining net peak loads;
    - Adjusting for extreme weather;
    - Comparisons to equipment ratings to determine if ratings will be exceeded;
    - Incorporating load transfers, phase transfers, correcting data errors;
    - Compiling GNA tables showing need amount and timing; and
    - Following the IOU's planning standard and/or planning process.
  - GNA/DDOR report review will include an in-depth analysis of the following IOU steps, among others:
    - Developing recommended solutions (planned investments);
    - Implementing the IOU's planning standards and/or planning process;
    - Estimating capital costs for planned investments;

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  - Developing list of candidate deferral projects through application of screens (timing and technical);
  - Developing operational requirements;
  - Prioritization of candidate deferral projects into tiers;
  - Calculating LNBA values; and
  - Comparing prior-year forecast and actuals at circuit level for candidate deferral projects.

- Work directly with the IOUs and Energy Division to develop draft plans as needed. Development of the draft IPE Plans may include, among other activities:
  - Meeting with the IOUs and Energy Division to identify and understand each business process and tool used to complete their GNA/DDOR filings.
- Facilitate or participate in stakeholder workshops to receive feedback on the IPE Plans.
- Review and incorporate comments in the final IPE Plans.
- Submit final IPE Plans to Energy Division and the IOUs with recommendations for future improvements to the plans.
- Other technical support assignments as defined by Energy Division to ensure the IPE and Energy Division will receive from the IOUs the data and cooperation necessary to complete the required evaluation of the GNA/DDOR filings.

<u>DPAG Period</u>

- Participate in all workshops and meetings during the DPAG period. Prepare and deliver presentations or handouts as requested by Energy Division (*e.g.*, final IPE Plan presentations).
- Develop an ***IPE Preliminary Analysis of GNA/DDOR Data Adequacy*** for all three IOUs.
- Review any comments on the preliminary analysis that may be received and discuss the results with Energy Division.

- Facilitate meetings with Energy Division and the IOUs to correct data inadequacies and prepare further documentation and provide technical support as needed.
- Fully implement each IPE Plan as defined in the final IPE Plans.
- Develop an ***IPE DPAG Report*** for each IOU presenting GNA/DDOR review findings and Verification & Validation outcomes.
- Submit the draft reports to Energy Division for review and (if necessary) to the IOUs to check for confidential information that may be included or to clarify specific details.
- Circulate the final IPE DPAG Reports to stakeholders (public and confidential versions).
- Other technical support assignments as defined by Energy Division to ensure the DPAG process is successfully completed.

Sample Size

- The scope of review conducted by the IPE for each IOU process may encompass the full set of circuits/projects or a subset/sample of circuits or projects. Where sampling is determined to be appropriate by the IPE in consultation with Energy Division, the size of the sample set for each case will be determined by the IPE based on the application of engineering judgement.

Post-DPAG Period

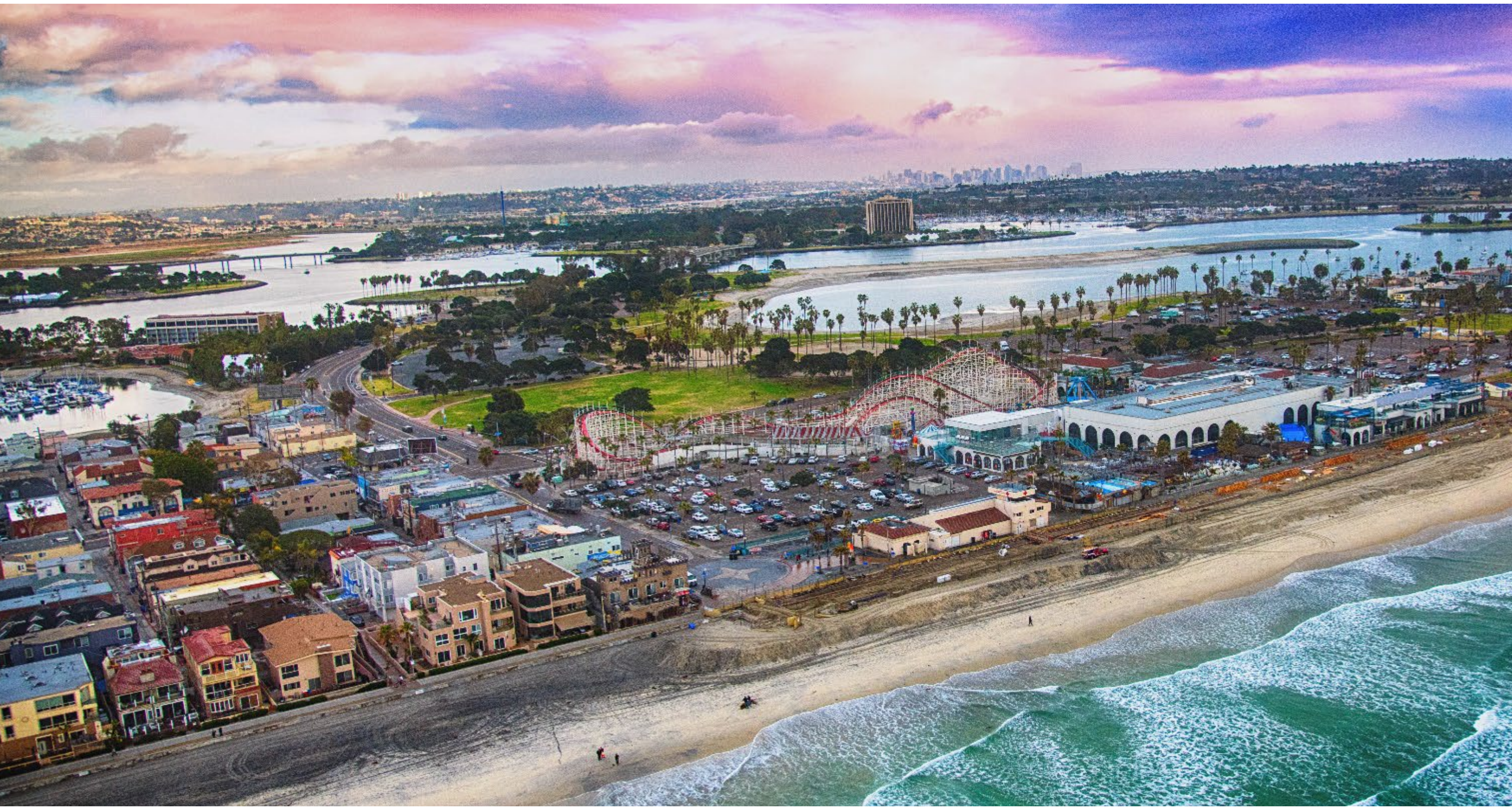
- Develop a single ***IPE Post-DPAG Report*** covering all three IOUs; comparing their current and prior filings; evaluating DIDF DER procurement, operational, cost, and contingency planning outcomes; reviewing IOU compliance; and making recommendations for process improvements and DIDF reform.
- Coordinate with and support the Independent Evaluator (IE) with IE activities and the development of IE reports as needed.
- Submit the draft report to Energy Division for review and (if necessary) to the IOUs to check for confidential information that may be included.

- Submit the final report to Energy Division and prepare public versions as needed.
- Support Energy Division with their review of DIDF reform comments, including comments on any IPE tasks.
- Support Energy Division's review of RFO materials and RFO outcomes.
- Attend RFO and procurement meetings and provide technical support as requested by Energy Division.
- Coordinate with the Independent Evaluator to support their evaluation and provide technical support at the discretion of Energy Division.
- Other technical support assignments as defined by Energy Division to develop and evaluate potential DIDF reforms and track and evaluate deferral opportunities that may be subject to ongoing review in other proceedings (e.g., pursuant to General Order 131-D).

List of IPE DIDF Deliverables

1. ***IPE Plan*** for each IOU describing the GNA/DDOR review process and approach to Verification & Validation for the underlying data.
2. ***IPE Preliminary Analysis of GNA/DDOR Data Adequacy*** for all three IOUs.
3. ***IPE DPAG Report*** for each IOU presenting GNA/DDOR review findings and Verification & Validation outcomes.
4. ***IPE Post-DPAG Report*** covering all three IOUs, comparing their filings, reviewing compliance, and making recommendations for process improvements and DIDF reform.

(end of Attachment B)



Contents

1. Introduction and Background

Summary of CPUC April 13, 2020 Rulemaking 14-08-013 and Other Rulemakings

The paragraphs that follow summarize the parts of the April 13, 2020 CPUC ruling and other rulings that directly impact the role of the IPE and/or this report.

The April 13, 2020 CPUC Ruling modified the Distribution Investment Deferral Framework (DIDF) process and filings with respect to the Independent Professional Engineer (IPE) scope of work and provided the updated 2020-2021 DIDF cycle schedule. Attachments A and B of the Ruling include a listing of the IPE-specific reforms discussed in the Ruling and the updated IPE scope of work. These Attachments to the Ruling are attached as Appendix A of this report.

In Decision 18-02-004, the Commission adopted the DIDF. Building upon the Competitive Solicitation Framework developed in the companion Integration of Distributed Energy Resources proceeding, the DIDF established an ongoing annual process to identify, review, and select opportunities for third party-owned distributed energy resources (DERs) to defer or avoid traditional capital investments by the investor-owned utilities (IOUs) on their electric distribution systems. Decision 18-02-004 ordered the IOUs to implement the DIDF as an annual planning cycle that would result in the selection of distribution upgrades for deferral through the competitive solicitation of DERs.

The DIDF was implemented in 2018 and 2019 with the expectation that it would be evaluated and revised after each cycle to improve the process. To that end, the assigned Administrative Law Judge (ALJ) issued a Ruling Requesting Answers to Questions to Improve the Distribution Investment Deferral Framework Process on February 25, 2019 (February 25, 2019 Ruling). Based on these comments, the ALJ issued a Ruling Modifying the Distribution Investment Deferral Framework Process on May 7, 2019 (May 7, 2019 Ruling). The parties have proposed additional recommendations for DIDF reform throughout the 2019 DIDF cycle. A Ruling Requesting Comments on Possible Improvements to the 2020 Distribution Investment Deferral Framework Process was subsequently issued on November 8, 2019 (November 8, 2019 Ruling), and the contents of this Ruling further modify the DIDF. A Ruling on May 11, 2020 modified the DIDF filing and process requirements including proposing a number of possible reforms to the DIDF followed by a ruling in June 2021 establishing new reforms and modifying some of those included in the May 11, 2020 ruling.

The CPUC issued Ruling 14-10-003 on 2/12/21 titled Decision Adopting Pilots to Test Two Frameworks for Procuring Distributed Energy Resources that Avoid or Defer Utility Capital Investments. In that ruling the CPUC added two additional procurement mechanisms to the DIDF cycle and spelled out these pilots are to be implemented over the next few DIDF cycles. The two new mechanisms are called the Standard Offer Contract, which applies to in front of the meter DERs, and the Partnership Pilot, which applies to behind the meter DERs. The ruling also includes some revisions to the DIDF process and timing which are followed in this cycle's IPE review and this report.

The IPE scope of work outlined in Attachment A provides for improvement to the IPE review process based on comments received and clarifies that the development of IPE review plans for each IOU will be overseen and approved by Energy Division. According to the Ruling, it is important the IPE has sufficient time to prepare the IPE Plans in advance of the GNA/DDOR filings and that after the filings, the IPE has the cooperation and coordination of the IOUs necessary to collect the data needed for review in time to prepare the IPE Preliminary Analysis of GNA/DDOR Data Adequacy and IPE DPAG Report.

The revised IPE scope reflected in Ruling 14-08-013 includes the requirement to develop an IPE Plan that will cover most if not all of the IPE activities. A copy of the Final 2022/2023 IPE Plan for SDG&E is included in Appendix C.

According to the Ruling, planning standards that lead to the identification of reliability needs need not be reviewed at this time. Instead, the IOUs should provide the IPE with planning documentation that supports the identification of all reliability needs. At this time, a formal review of IOU planning standards is not required as it could be a significant undertaking. However, the Ruling states that the Energy Division should discuss the 2020 GNA/DDOR filings with the IPE to determine if inconsistencies and shortcomings in the IOU planning standards exist and whether further review should be prioritized for future DIDF cycles.

The April 13, 2020 CPUC Ruling states that to further assist the IPE with DPAG Report completion, a new IPE Post-DPAG Report deliverable is included within the IPE scope of work. The IPE Post-DPAG Report should review and compare overall IOU DIDF compliance and make recommendations for process improvements and DIDF reform.

As stated in the May 7, 2019 Ruling, the IPE shall report directly to Energy Division to prepare its deliverables and conduct its analyses of DIDF implementation. The April 13, 2020 Ruling states the term of the IPE scope of work shall be the entire DIDF cycle, which starts on January 1 each year to plan for Pre-DPAG and DPAG implementation and concludes on July 31 the following year after all RFOs are concluded and all DIDF reforms are implemented. As a result, IPE scopes of work for each DIDF cycle will overlap.

The schedule and milestones established by the April 13, 2020 Ruling and as modified in subsequent rulings are shown below as they apply to the 2022/2023 DIDF cycle.

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IOUs) to enter into a contract with an Independent Professional Engineer (IPE). The role of the IPE is as previously described.

Through a contract with Nexant, Inc. (now a part of Resource Innovations), SDG&E engaged Mr. Barney Speckman[1], PE, to serve as the advisory engineer (referred to as the Independent Professional Engineer (IPE)) for the scope described in the April 23, 2020 CPUC Ruling or as modified by subsequent rulings.

This report which meets the requirements included in the CPUC ruling was provided to SDG&E in sufficient time to be included in their Advice Letter seeking approval to launch the second cycle of the Partnership Pilot.

1.1. IPE Plan

As required by the April 23, 2020 Ruling, the IPE developed an IPE Plan that served to guide the IPE's steps to implement its 2022 DIDF work scope. The plan was developed using a three-step process:

1. In step 1 IPE developed a draft IPE Plan working with the Energy Division and SDG&E by mid-May 2022.
2. The Plan was distributed to the service list and also discussed at the CPUC Distribution Forecasting Working Group meeting - both in an attempt to obtain stakeholder feedback on the plan.
3. Based upon stakeholder feedback received and under the direction of the Energy Division, the IPE revised the plan and made its IPE Final Plan available on September 21, 2022.

A copy of the Final IPE Plan is included as Appendix C.

The IPE Plan covers the business processes that the IOUs use to identify which distribution or subtransmission projects are recommended to proceed to a procurement process under which DERs are evaluated as potential cost-effective non-wires alternatives. One of the core purposes of the plan is answer the question - Are the IOUs identifying every planned distribution project that could feasibly and cost effectively be deferred by DERs?

The business processes in the Plan are organized generally in the order that they are performed. Starting with capturing the peak load values for each circuit for 2021, using the CEC IEPR forecasts to develop utility specific system level values which are then disaggregated to the circuit level, adjusted for known loads, and then used to determine if there is an overload or other issue during the planning period. For circuits that have a need, a planned investment is selected, capital costs

[1] Consistent with the CPUC decision, the contract with Nexant Inc., the firm where Mr. Speckman is employed, provides for other individuals within Nexant to assist Mr. Speckman to perform the work in the IPE contract provided that these other individuals are also bound by the same confidentiality and conflict of interest requirements that Mr. Speckman is required to meet.

developed for that project and the planned investments are screened to develop a list of candidate deferral projects. These candidate deferral projects are then prioritized into tiers using several metrics. The deferral projects in the first tier are judged to have a higher likelihood of being cost-effectively deferred than projects in the second and third tiers. Pursuant to the ALJ's May 2022 reform ruling, the utilities then apply a quantitative methodology to select which of the tiered candidate deferral projects will be offered for deferral through the pilots.

1.2. Definitions of Verification and Validation

As part of the development of the IPE Plan, detailed definitions were developed to clarify the meaning of Verification and Validation as applied to the IPE scope of work. These definitions which are used and applied in all IPE deliverables, are listed below:

Verification – Is a review performed by the IPE during which an independent check is performed to determine if the results produced were developed using data assumptions and business processes that were defined and described by the utility or are based upon standard industry approaches that do not have to be defined and described. In other words, "Did the IOU follow their own processes correctly as defined by the IOU?"

Validation – Is a review performed by the IPE during which an independent assessment is performed of the appropriateness of the approach taken by the utility to perform a task from an engineering, economics, and business perspective. In other words, "Are the processes implemented by the IOU the best way to identify all planned investments that could feasibly be deferred by DERs cost effectively? And to what extent were the IOU methodologies appropriate and effective?"

1.3. Services Considered within the DDOR Framework

The CPUC, in a previous decision, approved the four services proposed by the Competitive Solicitation Framework Working Group (CSFWG) and directed the utilities to consider these services in the GNA/DDOR process. The four services as described in the decision are listed below in an excerpt from the decision:

> "The following definitions for the key distribution services that distributed energy resources can provide are adopted for the Competitive Solicitation Framework:
>
> Distribution Capacity services are load-modifying or supply services that distributed energy resources provide via the dispatch of power output for generators or reduction in load that is capable of reliably and consistently reducing net loading on desired distribution infrastructure;
>
> Voltage Support services are substation and/or circuit level dynamic voltage management services provided by an individual resource and/or aggregated resources capable of dynamically correcting excursions outside voltage limits as well as supporting conservation

voltage reduction strategies in coordination with utility voltage/reactive power control systems;

Reliability (back-tie) services are load-modifying or supply service capable of improving local distribution reliability and/or resiliency. Specifically, this service provides a fast reconnection and availability of excess reserves to reduce demand when restoring customers during abnormal configurations; and

Resiliency (micro-grid) services are load-modifying or supply services capable of improving local distribution reliability and/or resiliency. This service provides a fast reconnection and availability of excess reserves to reduce demand when restoring customers during abnormal configurations."

1.4. Approach to Information Collection

The information reflected in this report was obtained through a number of methods including:

Written data requests sent to SDG&E regarding their planning process that led to the needs identified in their GNA Report and the projects included in their DDOR Report. Responses from SDG&E were made during follow up conference calls or in writing. A copy of written requests and written responses are included as Appendix D.

- Numerous calls with SDG&E were held prior to the development of this Final Report. Calls were held on average once every two to three weeks.
- Special calls were also held for SDG&E to provide demonstrations of certain business process steps as described later in the report.
- Participation in SDG&E's DPAG meeting and its follow-up DPAG Webinar.
- A review of publicly available materials referred to in the discussions with SDG&E or materials previously filed with the CPUC.

1.5. Report Contents

The remainder of this report includes the following sections:

- Section 2 – Review of GNA Report which briefly discusses the contents of the SDG&E GNA Report, and any significant differences noted in SDG&E's reports between the 2022 and 2021 DIDF cycle. Observations, comments, and recommendations that result from the Validation review with respect to the GNA Report are included in this section.

- Section 3 – Review of DDOR Report which briefly discusses the contents of the SDG&E DDOR Report, and any significant differences noted in SDG&E's reports between the 2022 and 2021 DIDF cycle. Observations, comments, and recommendations that result from the Validation review with respect to the DDOR Report are included in this section.

- **Section 4** – Review of Screening and Prioritization which discusses the screening and prioritization process and results. Observations, comments, and recommendations that result from the Validation review with respect to the screening and prioritization are included in this section.

- **Section 5** – Review of Candidate Deferral Projects which includes the review of projects that have been placed into the Tiers defined by SDG&E. Observations, comments, and recommendations that result from the Validation review with respect to the placement of projects in the SDG&E defined Tiers are included in this section.

- **Section 6** – Discussion of Other Topics of Interest. Observations, comments, and recommendations that result from the Validation review with respect to these topics are included in this section.

- **Section 7** – Verification completed which reviews the approach and results of the verification performed by the IPE

- **Appendix A** – IPE Scope - Excerpt from April 23, 2020 CPUC Rulemaking 14-08-013

- **Appendix B** - Comments Received from the DPAG Members and IOU and IPE responses.

- **Appendix C** – IPE Final IPE Plan - SDG&E

- **Appendix D** - SDG&E Data Requests and Responses

Confidential Information

2. Review of GNA Report

The GNA Report submitted by SDG&E is summarized at a high level below.

2.1. Scope of SDG&E's GNA/DDOR Reports

The SDG&E GNA Report is a written report with an accompanying Excel spreadsheet of potential grid needs on its distribution system. SDG&E filed its GNA and DDOR Reports on August 15, 2022 as required by the CPUC.

SDG&E's 2022 GNA report is organized similar to the 2021 report under the following sections:

- Distribution Planning Process
- SDG&E's Distribution Resources Planning Assumptions and GNA Scope
- GNA Results
- Updates to the GNA

The report contains the following appendices:

- Appendix 1 – Load Disaggregation
- Appendix 2 – Substation Bank and Circuit Forecast Detail Summary
- Appendix 3 – DER Disaggregation Process

2.1.1. Distribution Planning Process

SDG&E's distribution planning process, which remains unchanged from 2021, begins with assessing the historical peak load review for circuits and banks. SDG&E then makes adjustments to the historical peak load considering factors such as, anticipated new load additions, load transfers, loss of a generator, and weather conditions at the time of the historical peak, etc.

SDG&E uses a third-party proprietary software forecast toolset from Integral Analytics, Inc. (LoadSEER GIS) to disaggregate the load forecast provided by the California Energy Commission (CEC) to a circuit level. They also use another third-party software (SPIDER - Spatial Penetration & Integration of Distributed Energy Resources) to disaggregate some of the CEC's IEPR Distributed Energy Resource (DER) forecast components such as light duty electric vehicles (LDEV), photovoltaic solar and energy storage, to the zip code level. SDG&E then maps the zip code level forecast from SPIDER to circuits based on the customer counts on each circuit within the given zip code.

All of this data is used in LoadSEER to obtain 576 hourly net load circuit forecasts (typical weekday and weekend loads for each month) which are then reviewed by SDG&E's distribution planning engineers to identify and correct errors, to address technical issues, and to validate the circuit level forecasts for overall reasonableness.

SDG&E also develops power flow models in Synergi by extracting circuit models from its Geographic Information System (GIS) and forecasts from LoadSEER. These power flow models are used to investigate voltage needs, as well as capacity needs at the line segment level.

SDG&E investigates if any of the forecasted grid deficiencies have operational-based solutions (which have little to no associated capital investment), contain forecast discrepancies, and/or have committed planned investments that were identified in a previous DIDF cycle. Based on this analysis, SDG&E provides a list of distribution needs that would result in new distribution capital infrastructure, if built. These are included in the DDOR as Planned Investments and, if they pass defined screens, listed in the DDOR as candidate deferral projects.

2.1.2. SDG&E's Distribution Resources Planning Assumptions and GNA Scope

This section discusses the methodology and assumptions related to load forecasts, DER growth forecasts and distribution operational switching/load transfer criteria used to forecast and identify distribution needs that are reflected in SDG&E's 2022 GNA.

SDG&E's Distribution Resources Planning Horizon

SDG&E's 2022 GNA covers the 2022-2026 five-year planning horizon. As in the 2021 GNA, SDG&E uses only the first three years of the five-year forecast when identifying needs associated with downstream line segments of a circuit.

SDG&E's Distribution System Load Forecast Assumptions

SDG&E uses the California Energy Commission's IEPR forecast "CED 2020 Load Modifiers – Mid Baseline Mid AAEE with CAISO with 2031" forecast as the starting point for forecasting circuit-level loads. SDG&E uses a process to adjust the CEC's forecast for known load additions and identify remaining load to be disaggregated in the forecasting models. This process was verified by the IPE and is further discussed in Section 2.4 of this report.

The resultant system-level growth, allocated by customer class (residential, industrial, and commercial) is disaggregated to a circuit level using the LoadSEER GIS geo-spatial forecasting program which employs satellite imagery and proprietary data analytics to score each acre in SDG&E's territory for the likelihood of increased load by customer class. The circuit-level load forecasts are entered into the LoadSEER forecasting program which generates the 576-hourly load profiles for each circuit. LoadSEER applies an adverse weather factor to each circuit to create the 1-in-10 weather year forecast which is the basis for development of distribution grid needs. Another input to LoadSEER is the most recent summer weather data and historical substation loading which is then adjusted for a 1-in-2 weather year. SDG&E also employs several steps to validate and adjust historical peak loads to establish a starting point for distribution loading projections that are consistent with the existing circuit configuration on a going-forward basis.

*Note: Based on a field visit by the crew, it was determined that the phase balance was not required.

GNA Scope

SDG&E's 2022 GNA identifies distribution grid needs associated with the four distribution services that the Commission determined that DERs may be able to provide: distribution capacity, voltage support, reliability (back-tie), and resiliency (microgrid). The GNA identifies distribution capacity, and reliability (back-tie) services needs at the circuit level, substation transformer bank level and the line segment level. Since SDG&E does not have any transmission projects that come under the jurisdiction of the CPUC, no transmission level needs are identified in the GNA. Also, according to SDG&E, none of their Pre-Application and Post-Application projects include distribution components that address a distribution need identified through the distribution planning process, and none can be deferred by DERs since all are associated with transmission projects that are not subject to deferral by DERs through the DIDF.

Distribution needs that would result in new distribution capital infrastructure, if built, are included in the DDOR as Planned Investments and, if passing defined screens, listed in the DDOR as Candidate Deferral Opportunities ("CDOs"). DDOR CDO determination begins with a thorough review of previously identified GNA needs to develop the best solution to address the needs. Typically, the least cost, best fit solution to resolve identified needs is to utilize existing equipment, which often also allows rapid implementation. If needs cannot be appropriately mitigated using existing equipment, the option of installing new equipment is explored.

GNA Refinements

SDG&E's 2022 GNA identified refinements subsequent to the internal dissemination of the distribution load forecast and prior to the publication of the GNA/DDOR on August 15, 2022. These refinements included the removal of a need (Circuit 549) that was identified earlier, the addition of a new need (Circuit 369) due to an additional load request, and the revision of a need (Circuit 493) due to an additional load request.

Other Topics

Other topics covered in the GNA report include a discussion of data that is covered by customer confidentiality (15/15 rule), and the modeling discrepancies such as duplicated load additions and ampacity ratings that were found and corrected in the planning process. There were no modeling deficiencies identified in the 2022 GNA.

2.2. Changes to GNA for 2022

There are no changes in data formats between SDG&E's 2022 GNA and SDG&E's 2021 GNA.

2.3. Discussion of GNA Results

SDG&E's 2022 GNA identified a total of 20 needs related to distribution capacity, voltage or resiliency and 2 circuits that had a back-tie (reliability) need in addition to a capacity need. SDG&E has indicated in prior cycles that a back-tie need is included for any traditional project that would potentially provide additional back-tie capability. The back-tie need is not based on a separate analysis of the need for such a back-tie capability. Discussion on SDG&E's back-tie analysis can be found in Section 2.4 of the 2021 IPE report. Table 2-2 shows a summary of the grid needs by distribution service type and by the type of equipment on which a constraint requiring mitigation was identified. Table 2-3 shows the dates by which mitigation must in place. As mentioned earlier, two of the needs are addressed using very low-cost load transfers.

Table 2-4 shows the actual list of needs from the 2022 GNA report. All the capacity, voltage, reliability needs shown in the table are new needs driven by growth in demand and DERs. The table includes 4 microgrids in as much as reform #2 in the ALJ's May 11, 2020 reform ruling requires the utilities to list all planned utility-owned DER solutions not categorized as CDOs.[2] As part of the Microgrid OIR, SDG&E received Commission approval for four microgrids, each of which includes planned utility-owned circuit-level energy storage projects (collectively, the Microgrid Projects). The Microgrid Projects provide local grid resiliency. Sixteen of the 22 needs arise due to deficiencies in the second year of forecast (i.e., 2023) and the remaining 6 needs during the following year.

Section 7 of this report includes a verification of how the net loads and deficiencies (i.e., overloads) on the distribution lines are calculated for those lines that have proposed planned investments.

Table 2-2: Summary of the Number of Grid Needs by Distribution Service Type and Equipment Type

– Equipment Type	Distribution Service				Total
	Peak Thermal	Voltage	Back-Tie	Microgrid	
Substation Bank	3	0	2	0	5
Circuit	3	0	0	4	7
Line Segment	6	4	0	0	10
Totals	12	4	2	4	22

[2] "In the DDOR list of planned investments, the IOUs shall identify all DER solutions planned for IOU ownership or otherwise planned for procurement but not prioritized as deferral opportunities."

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[illegible]	0	0	0	0	0
[illegible]	8	4	0	4	16
[illegible]	4	0	2	0	6
[illegible]	0	0	0	0	0
[illegible]	0	0	0	0	0
[illegible]	12	4	2	4	22

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2.4. GNA Observations, Conclusions and Recommendations

- The total number of grid needs in the 2022 GNA was approximately the same as what was seen in the 2021 GNA, i.e., 22 needs in 2022 versus 24 needs in 2021. However, there were 4 microgrid-related needs in the 2022 GNA and none in the 2021 GNA. (There were also 4 microgrid-related needs in the 2020 GNA.)

- In the 2022 GNA, all of the needs were in the first three forecast years compared to the 2021 GNA where 19 of the 24 needs were in the first three years.

- The total known load additions in the first three years decreased from 152.5 MW in the 2021 GNA to 116 MW in the 2022 GNA. However, known loads specifically identified as transportation-related in the first 3 years grew from 16.6 MW in the 2021 GNA to 26 MW in the 2022 GNA. A pie chart of the total known load additions in the first 3 years by customer type is shown in the Figure 2-1 below for the 2021 and 2022 GNAs.

Figure 2-1: Known Load Customer Types and Load (MW) in the 2021 and 2022 GNA

(Note: The plot below contains confidential information and is redacted in the public report)

- As observed in the last cycle, the cumulative known load additions in the first three years are higher than the cumulative load growth forecasted in the CEC IEPR for the same period. As a result, the load forecast used in the GNA for the first three years is higher than the CEC IEPR forecast. Starting with year four, the load forecast used in the GNA is the same as what is in the CEC IEPR. A comparison of the cumulative and annual load growths between the GNA and IEPR forecasts are shown in Figure 2-2 and Figure 2-3 respectively.

Figure 2-2: Cumulative load forecast growth for the 10-year period

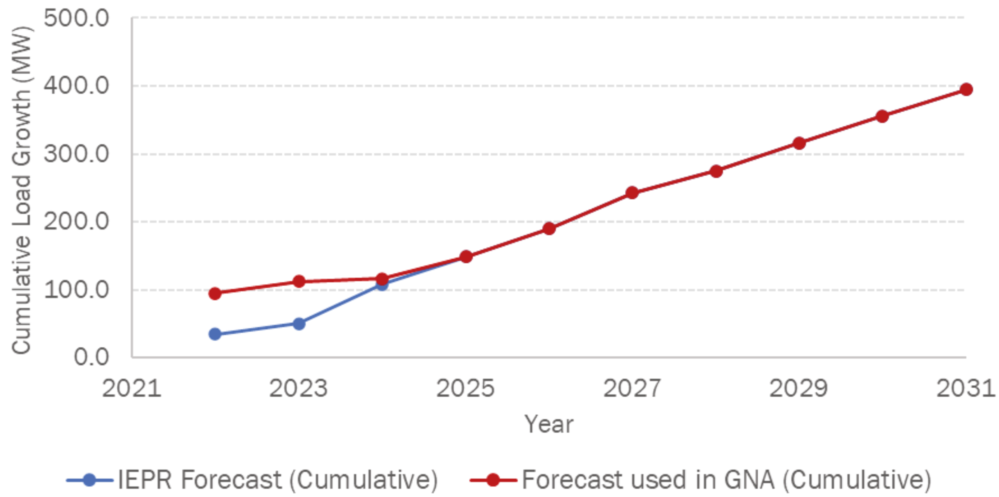
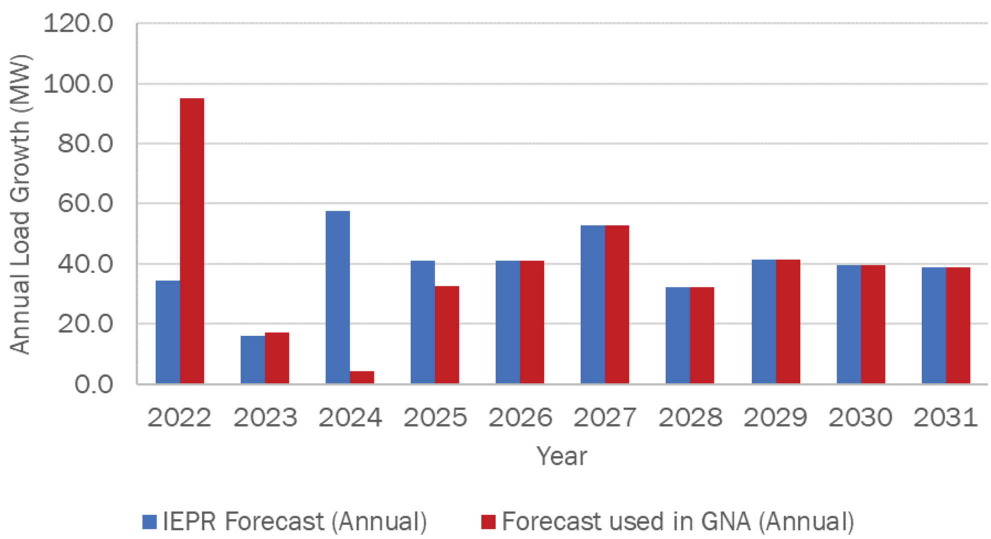


Figure 2-3: Annual load forecast growth for the 10-year period



- In the 2022 GNA, SDG&E has made a recommendation to modify Decision 16-12-036 to eliminate “resiliency (microgrids)”as a planned investment that is deferable by DERs. Their recommendation stems from their observation that multi-customer/premise microgrids use the utility’s infrastructure and require the utility to develop and operate the microgrid. Other utilities have proposed non-microgrid solutions to “resiliency” needs identified through the GNA. These non-microgrid solutions can be deferred using DERs. In the Post-DPAG report, the IPE plans to investigate the approaches used by the three IOUs in identifying and solving resiliency needs. Based on this investigation, recommendations regarding the inclusion of resiliency needs in the GNA, revisions to the definition of resiliency if included in the GNA, and the types of resiliency projects that are deferrable, will be made.

- The IPE observes that transportation-related known loads (primarily, EV charging stations) have increased in the current planning cycle when compared to the last cycle, albeit by a small amount as noted above. With California's goal of 100% zero-emission vehicle by 2035, it can reasonably be expected that the transportation-related loads will increase in the near future. It is not only important for the utilities to know the location, timing and peak load impact of these new loads, but also have this information as far in advance as possible to make sure any grid needs are addressed in a timely manner in order to support California's zero-emissions goal. It is important for utilities to engage with charging station developers and fleet operators to have the most up-to-date information on their plans. The IPE plans to investigate how the utilities currently engage with these constituents and report the findings in the Post-DPAG report.

3. Review of DDOR Report – Planned Investments

The DDOR begin with SDG&E's distribution planning engineers reviewing the needs identified in the GNA to determine a least cost, best fit and just-in-time solution to mitigate them. Typically, the least cost solution to resolve identified needs is to utilize existing equipment, which can also allow for rapid implementation. These include "no cost" load transfers and phase balancing which were discussed in Section 2.1.2. SDG&E engineers explore other options such as installing new circuits or reconductoring existing circuits if the needs cannot be appropriately mitigated using existing equipment.

SDG&E's 2022 DDOR provides an overview of seventeen (17) planned investments associated with the twenty-two (22) needs identified in the 2022 GNA. Of the twenty-two (22) needs identified in the GNA, two (2) needs are solved by load transfers as shown in Table 3-1. The remaining twenty (20) needs are addressed through seventeen (17) planned investments. Section 7 of the report (Step 10) reviews the loading of the receiving circuit before and after the transfer. As shown in the table, the loading from facility 2022_1003 is transferred to a new circuit which is part of a Reliability Substation Rebuild project that was initiated prior to the Distribution Resource Plan (DRP) and DIDF process.

Table 3-1: Needs addressed by load transfers

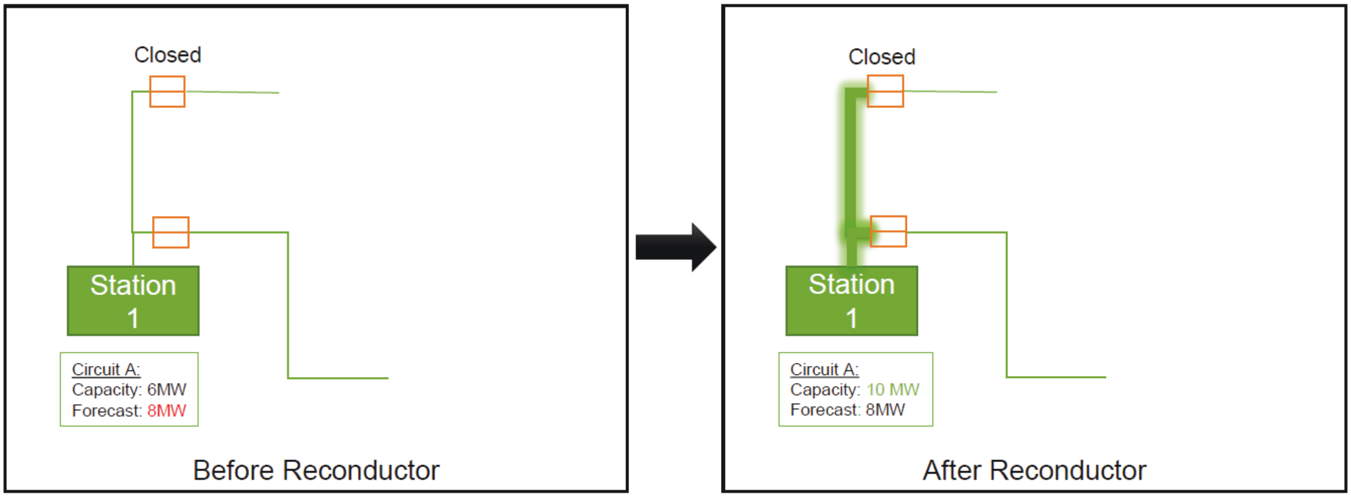
GNA_ID (From Circuit)	Facility ID (From Circuit)	Facility ID (To Circuit)	MW Transferred
GNA_2022_0013	2022_1003	New Circuit	[redacted]
GNA_2022_0015	2022_1002	2022_0366	[redacted]

Table 3-2 shows the information for the planned investments provided in Appendix A of the DDOR report. All of the planned investment projects have an in-service date in the year 2023 or 2024. The planned projects are as follows: (i) Three (3) new bank/circuit projects, (ii) four (4) projects that involve reconductoring or add a new conductor, (iii) Five (5) projects that involve a capacitor or voltage regulator, and (iv) Four (4) microgrid projects. SDG&E provided illustrative examples of planned project types which are reproduced below for convenience.

Reconductor

In this project type, the limiting element which is a conductor rated at 6MW is reconductored using a larger (10 MW) size conductor as show in in Figure 3-1.

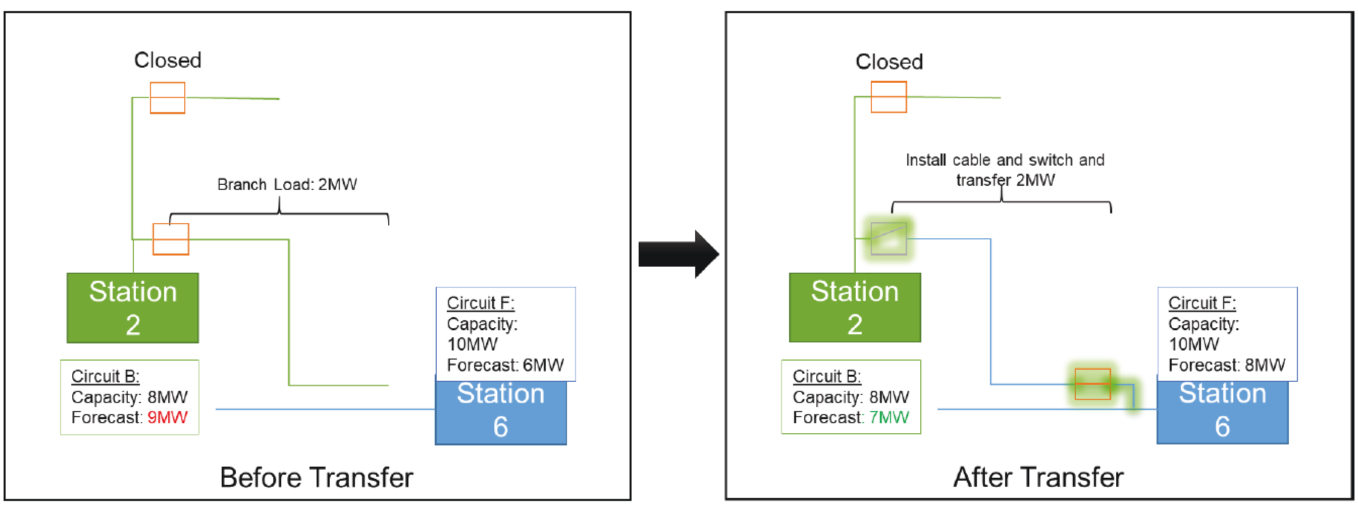
Figure 3-1: Figure showing an example project that involves reconductoring



Load Transfer with New Equipment

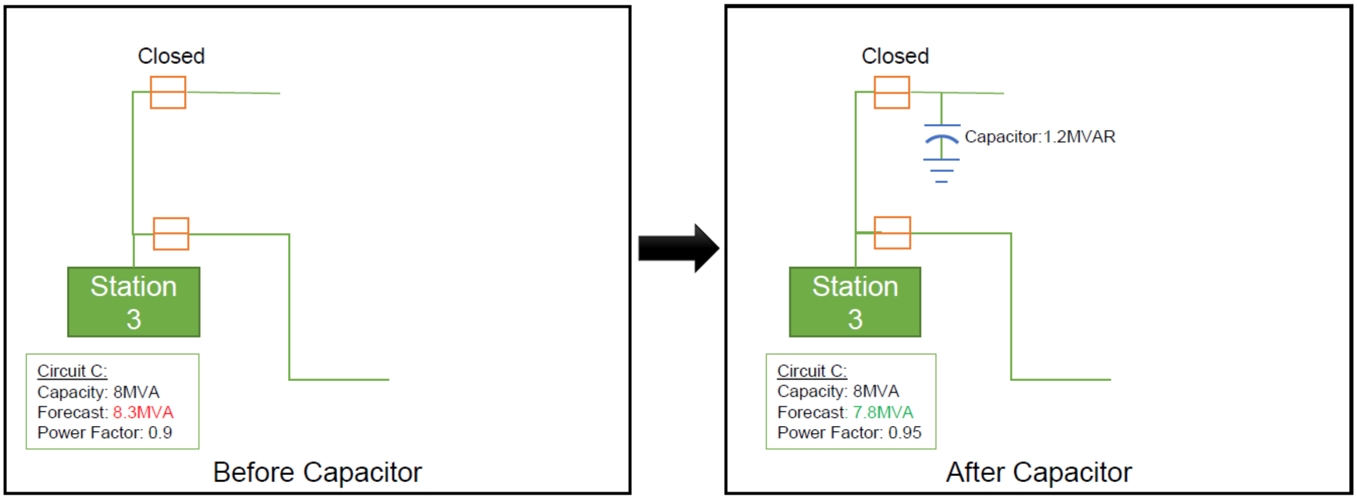
In this project type, Circuit B is expected to overload in the future. One of the laterals of this circuit is transferred over to a neighboring station (Station 6) using a new circuit and a switch. With this load transfer, the forecasted load remains below the rating of the circuit. This is shown in Figure 3-2.

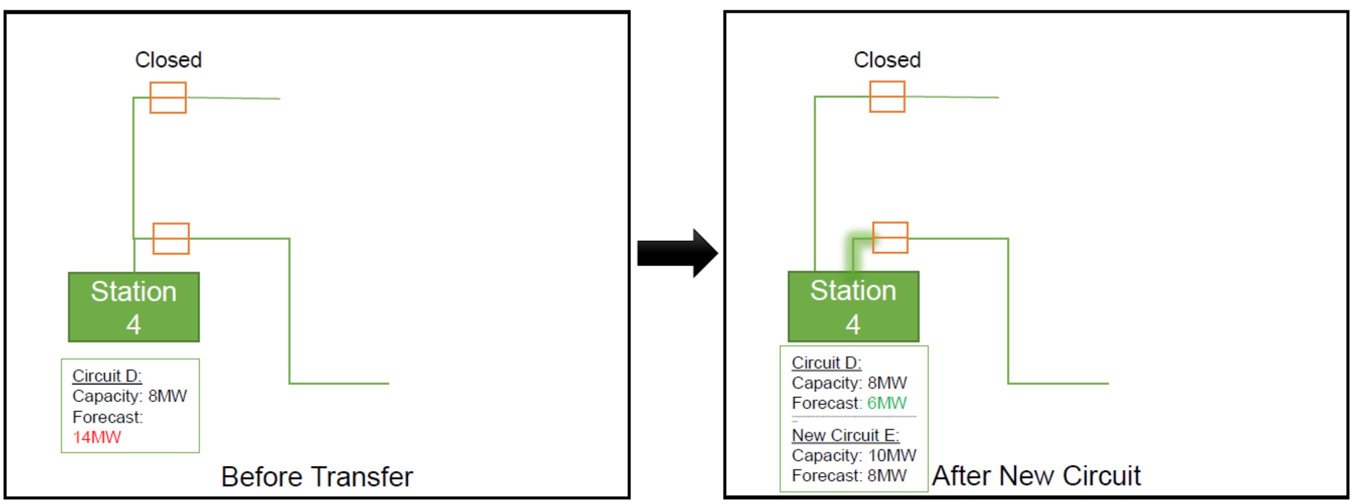
Figure 3-2: Figure showing an example project that involves a load transfer



New Capacitor

In this project type, Circuit C is expected to be above its MVA rating. The solution is to add a capacitor to the circuit to provide reactive power support. A voltage regulator project is similar to a capacitor project. This is shown in Figure 3-3.


Closed
Station 3
Circuit C:
Capacity: 8MVA
Forecast: 8.3MVA
Power Factor: 0.9
Before Capacitor
Closed
Capacitor:1.2MVAR
Station 3
Circuit C:
Capacity: 8MVA
Forecast: 7.8MVA
Power Factor: 0.95
After Capacitor


Closed
Station 4
Circuit D:
Capacity: 8MW
Forecast:
14MW
Before Transfer
Closed
Station 4
Circuit D:
Capacity: 8MW
Forecast: 6MW
New Circuit E:
Capacity: 10MW
Forecast: 8MW
After New Circuit

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3.1. DDOR Report Planned Investments - Observations, Conclusions and Recommendations

The 2022 DDOR had 17 planned investments compared to 12 planned investments in the 2021 DDOR. These planned investments had in-service dates in the same year as the need.

4. DDOR Report – Methodology for Screening and Prioritization and Pilot Project Selection

4.1. Project Screens

This section contains a discussion of the screens that SDG&E used to identify CDOs from its list of Planned Investment Projects. SDG&E used both a technical screen and a timing screen to screen projects in the process of developing a list of CDOs. The screens included:

Technical Screen

The purpose of the Technical Screen is to identify the distribution services DERs can provide to potentially defer a distribution project, and whether there are any technical deferral limitations associated with certain projects.

Timing Screen

The purpose of the Timing Screen is to ensure cost-effective DER solutions can be procured with sufficient time to fully deploy and begin commercial operation in advance of the forecast need date. Three years (by Year Four) is the earliest year considered adequate to successfully procure, contract, design, develop, market, and deploy DER solutions for these services.

Based upon our review, the screening was performed in a manner that is consistent with prior CPUC rulings. Following the application of the technical and timing screens there were no candidate deferral opportunities since all the planned projects are within the first three years of the five-year forecast horizon. SDG&E stated that in support of the pilot for this cycle, they will submit a CDO from the last cycle (Circuit C1202) as a candidate deferral opportunity.

4.2. Determination of Operational Requirements

SDG&E uses the following process for developing the operational requirements for DER projects. Please note that operational requirements were not calculated in this cycle since there were no candidate deferral projects. However, as discussed in the previous section, there was one CDO from the 2021 cycle that is recommended for deferral through the partnership pilot. For this CDO, the operational requirements calculated in the 2021 will be used in the procurement process. This section provides the process used for calculating the operational requirements in the last cycle.

- First, SDG&E uses the P95 net load profile for the circuit/bank and its rating to determine the overloads and hours and months during which the overloads occur during the deferral years, i.e., for the years 2025 through to 2030.

- SDG&E uses the maximum overload as the Capacity (MW) that is needed from DERs. For example, if the maximum overload occurs in hour 19 in the year 2030, this overload sets the DER capacity requirement for all the overloaded hours in that year.
- The duration for which DER needs to provide this capacity is determined adding an hour before and after to the hours during which there is a forecast overload. For example, if the overload occurs in hour 19 is the year 2025, the duration for which the DER needs to operate is determine as hours 18 through 20. Similarly, if the forecast overloads occur in hours 19-22 is the year 2030, the duration for which the DER needs to operate is determined as hours 18 through 23.
- The "Energy Need (MWh)" is reported on a per-day basis and is determined by multiplying the capacity requirement by the "Duration". The "Duration" is reported as the number of hours per day. For example, if 0.5 MW is needed for 6 hours each day, then the energy need is 3 MWh each day.
- To calculate the "Yearly Frequency" (e.g., how many times the overload occurs and hence the number of times per year that the DER solution could be called on to provide distribution service), SDG&E assumes that if there is an overload on either a weekend or weekday of each month, then the overload has the potential to occur in any or all days of the month. For example, if the 576 data shows overload in a typical weekday in July through September, then SDG&E assumes that the frequency of occurrence of the overload is 92 (overload occurs each day in July (31 days), August (31 days) and September (30 days)).
- Since the peaks could occur in the summer months (typically, June through October), the period during which the DER needs to provide the distribution service includes all of these months.
- If the DER also needs to meet a back-tie need, then the duration of operation required for back-tie service is also included as an operational requirement. The number of hours the DER is required to operate to relieve an overload on a neighboring circuit is set to 2 hours by SDG&E as established in Appendix of the 2018 GNA Report. The period during which the back-tie service needs to be available is all hours of the year (8760 hours) since outages can occur at any time.

Table 4-1 shows the operational requirements for the CDO from the 2021 DIDF cycle that has been recommended for the Partnership Pilot. The verification of the operational requirements can be found in the 2021 IPE DPAG report.

Table 4-1: Operational Requirements for Tier 1 Projects

GNA ID	DDOR ID	Facility ID	Distribution Service Required	Capacity (MW)	Energy Need (MWh)	Hour of Day	Duration	Time of Year	Yearly Frequency	Year
GNA_2021_0002	DDOR_2021_0002	2021_0279	Thermal							2021
			Thermal							2022
			Thermal							2023
			Thermal							2024
			Thermal	0.86	7.74	14-22	9	June - October	62	2025
			Thermal	1.46	16.03	13-23	11	June - October	92	2026
			Thermal	1.58	17.35	13-23	11	June - October	92	2027
			Thermal	1.51	16.65	13-23	11	June - October	92	2028
			Thermal	1.45	15.95	13-23	11	June - October	92	2029
			Thermal	1.39	13.88	14-23	10	June- October	92	2030

4.3. Project Prioritization

This section contains a discussion of the prioritization process used by SDG&E to prioritize its candidate deferral projects and a discussion of the various metrics SDG&E used during that process. This is the second DIDF cycle in which the three utilities are using a jointly developed project prioritization methodology in the form of an Excel workbook.

As required by CPUC Reforms #19 and #20 of the May 2020 ALJ Ruling, the IOUs were required to develop a Joint Prioritization Workbook Template for approval by the CPUC. The joint workbook was presented to the CPUC and subsequently approved by the CPUC on May 14, 2021. The Joint Workbook maintains the use of the three previously CPUC approved metrics – Cost-Effectiveness, Forecast Certainty, and Market Assessment. These three areas have quantitative metrics and qualitative metrics. The quantitative metrics are used to rank the CDOs and to place into one of three Tiers – either Tier 1, Tier 2, or Tier 3. The qualitative metrics are used to Flag projects for project attributes that the utility believes, based upon past experience, would make a project unlikely to be deferred by a DER. The Flags are applied after the projects are ranked using the quantitative metrics and override the ranking by automatically placing them into Tier 3. These metrics are listed below.

Quantitative Metrics
For Cost-Effectiveness

- LNBA ($/MW-yr)
- LNBA ($/MWh-yr)

For Forecast Certainty

- Grid Need Certainty (SDG&E used a Level of Certainty Questionnaire completed by Planning Engineers)

For Market Assessment

- Duration of Need (Hours)
- Capacity Need (MW)/Circuit

Qualitative Metrics
For Cost-Effectiveness

- Unit Cost of Traditional Mitigation ($) (Flagged if project capital cost exceeds threshold value set by each utility)

For Forecast Certainty

- Year of Need (Flagged if Operational date is after threshold year set by utility)

For Market Assessment

- Operational Requirement (Flagged if Real Time response needed by DER)
- Number of Grid Needs (Flagged if number of needs exceed threshold value set by utility)

The Joint Prioritization Metrics Workbook template quantifies how projects are tiered by assigning a Red-Amber-Green (RAG) score to each project. This method also considers the flags applied to each project. The RAG score is calculated by assigning a +1 score to first quartile projects, a 0 score to second/third quartile projects, and a -1 score to bottom quartile projects across each prioritization metric. Projects with a total RAG score greater than 0 are assigned to Tier 1, projects with a total RAG score equal to 0 are assigned to Tier 2, and projects with a total RAG score less than 0 or a flag in any one of the prioritization metrics are assigned to Tier 3.

Since there is only one CDO, and the template is set up for ranking and tiering multiple projects, many of the entries in the template could not be populated.

4.4. Selection of Projects for Standard Offer Contract and Partnership Pilot

SDG&E has identified no potential candidate projects for deferral by cost-effective DER in SDG&E's 2022 DIDF cycle. However, the 2021 GNA identified a need for an upgrade on C1202. In 2021, this need was submitted for participation in the SOC pilot and received no offers. SDG&E additionally sent this need through the RFO process and received no offers. As such, an SDG&E upgrade project has been planned to address the grid need. In support of cycle 2 of the Partnership Pilot, SDG&E intends to offer for deferral the planned upgrade to C1202.

The ALJ's June 16, 2022 DIDF Reform order required that each utility develop, document, and implement a quantitative ranking method for the Standard-Offer-Contract pilot and Partnership Pilot project selection in their 2022 Grid Needs Assessment/ Distribution Deferral Opportunity Report. A brief summary of quantitative process proposed by SDG&E is given below.

- Calculate average annual household income (in thousands of dollars) for the ZIP codes impacted by the CDO.
- Use SPARC GIS data to match the geographic locations impacted by the CDO to CPUC Fire-Threat and assign a threat code to the CDO (threat codes are 1 – 3).
- Compute a Pilot Assignment Metric for each CDO. Pilot Assignment metric = (Average Income X Risk Score)/(Prioritization Metrics Workbook Tier).
- CDOs with Pilot Assignment Metric greater than 83 will be subject to deferral through the SOC Pilot or Partnership Pilot.

4.4.1. Project Prioritization and Pilot Project Selection – Observations, Conclusions and Recommendations

Prioritization

- As stated earlier, there are no candidate deferral opportunities in this cycle since all the planned projects are within the first three years of the forecast horizon. However, SDG&E will submit a CDO from the last cycle (Circuit C1202) as a candidate deferral opportunity for this cycle. This CDO was prioritized as a Tier 1 project in the 2021 DIDF cycle. This tier designation has been carried-forward into the current DIDF cycle.

Operational Requirements

- The operational requirements for the CDO as assessed in current cycle are virtually the same as determined in the prior cycle. Accordingly, SDG&E proposes to use the requirements determined in the last cycle in the current cycle's procurement process. The IPE made a number of observations regarding the methodology that SDG&E uses for developing the operational requirements which are repeated below for convenience.
- SDG&E determines the energy need (MWh) for a DER solution by taking the maximum overload (MW) times the duration (hours) for which the DER needs to provide service. As

mentioned in Section 4.2, the duration is determined by adding an hour before and after to the hours during which there is an overload. Due to the added two hours, the energy need calculated is higher than what might be required during overloaded conditions.

- Further, we believe that SDG&E takes a conservative approach when it develops required frequency of operation. SDG&E views that if the 576-hourly profile analysis shows one overload in a typical weekday or weekend, then all the days of that month are overloaded. For example, if the 576-hourly profile analysis shows a single hour of overload during a weekday or weekend in any of the months of August through October, then SDG&E calculates a frequency (number of times a DER could be called to provide distribution services) of 92 (31 days + 30 days + 31 days). While the peak load can occur on any of these 92 days it is not likely that it will occur on every day in this 92-day period. Using the 92-day value has an impact on CDO prioritization (the Market Assessment metric) and has the potential to impact procurement as well, as discussed below.
    - In the joint prioritization template, the cost effectiveness metric LNBA in $/MWh-yr is calculated by dividing the LNBA by the estimated energy provided by the DER in a year. Since the frequency as calculated by SDG&E is conservative (higher than the actual number of times a DER might be called to provide distribution service), this LNBA value tends to be lower. The potential result is that projects with needs in more months will be ranked lower.
    - For procurement through the RFO competitive solicitation process and the Standard Offer Contract pilot, these higher frequency values may discourage resources such as demand response from participating and may also result in higher offer prices since Developers will assume that resources will have limited opportunities to earn other revenue streams (since the frequency of calls to provide distribution services is potentially high).
- For projects that need to solve a back-tie need in addition to a thermal need, SDG&E requires the DER solution to be able to meet the maximum load (MW) for a 2-hour period during hours 0-23 for all months of the year. For example, DER(s) providing distribution service for the DDOR_2021_0003 (North City West C832) project must have the capability to provide 0.51 MW for 6 hours (i.e., 3.05 MWh/day) in the year 2030 to meet the thermal need. Since this project also has a back-tie need, the DER(s) should also have the capability to provide 0.51 MW for 2 hours.

Based upon information provided by SDG&E, back-tie service would not be additive to the thermal service. That is if the DER(s) is called to provide thermal (NWA) service and back-tie service at the same time, the resource will satisfy both the back-tie service and peak thermal service requirements provided that the larger of the two amounts directed by SDG&E is delivered. This means that for North City West C832 which has a peak thermal need of 0.51 MW and a back-tie need of 0.51 MW, the DER(s) need to provide 0.51 MW of service and not 1.02 MW (i.e., 0.51 x 2). However, given the back-tie service could theoretically be requested at any hour (based upon our understanding) which means that the DER(s) would have to have the capability to provide back-tie service for 2 hours just prior to or immediately after providing distribution service for 6 hours. In these cases, there may not be sufficient time for an energy storage resource to be recharged to immediately provide service. In this worst case, the DER(s) potentially would need to be sized to provide

0.51 MW for 8 hours (i.e., 4.08 MWh) or 33% larger than it would be sized for thermal service only. This worst case would have an impact on the cost of the DER solution. This is not only applicable for energy storage, but also for other dispatchable resources such as demand response which may have to be called for a longer duration at a stretch, thus impacting its viability.

Pilot Project Selection

- In the 2022 GNA, SDG&E proposed a quantitative ranking method for the Standard-Offer-Contract pilot and Partnership Pilot project selection. This methodology was summarized in Section 4.4. The pilot assignment metric proposed in this methodology depends on three factors – the average annual ZIP code level salary, the CPUC Fire-Threat code and the tier into which each CDO is placed. Selection for a pilot is based on the metric exceeding a threshold value of 83. The IPE did not evaluate the efficacy of the proposed methodology since SDG&E did not employ this methodology in this cycle due to having only one CDO. The IPE plans to compare the methodology used by all three utilities for the Standard-Offer-Contract pilot and Partnership Pilot project selection in the post-DPAG report. The IPE will also jointly work with SDG&E to propose changes to its methodology based on the lessons learned from the comparison.

5. Review of SDG&E's Prioritization of Candidate Deferral Projects and Pilot Selections

- As stated previously, SDG&E will submit a CDO from the last cycle (Circuit C1202) as a candidate deferral opportunity for this cycle. SDG&E has carried over, into the current DIDF cycle, the prior DIDF cycle's Tier 1 designation for this CDO. In 2021, SDG&E submitted this CDO for participation in the SOC pilot, as well as through the RFO process and received no offers in either solicitation. Since the Commission-adopted staff proposal requires that at least one Tier 1 candidate deferral project be offered for the Partnership Pilot,[3] SDG&E has planned to propose this CDO for the partnership pilot in this cycle. The IPE notes that the low budget (less than 1 Million in deferral value) and long duration of the need (9 hours) could be the likely factors behind receiving no offers in either solicitation.

[3] The Commission-adopted staff proposal states that the "…IOUs…pilot the [Partnership Pilot with] …one Tier 1.…All other Tier 1 opportunities should be…for…RFO or the SOC". Staff proposal at p. 11.

6. Other Items of Interest

6.1. Known Load Tracking Project Dataset

The ALJ's June 16, 2022 DIDF Reform order required all three IOUs to track known load projects in the 2022 GNA/DDOR. The reform also required the known load tracking dataset to include a unique project identifier, impacted circuit, initial service request date, load amount, current expected in-service date or indication if service request was cancelled, if appropriate, and type/category of load and, if appropriate, the actual date service was initially provided and the amount. SDG&E provided this data as Appendix B of their GNA-DDOR report.

The IPE reviewed the data sent by the three IOUs and found that there were various interpretations of the request and different approaches to providing the data. The IPE recommended that a set of definitions similar to the one shown in Table 6-1 be used by all three utilities. The IPE plans to follow up with all three utilities and the Energy Division to better understand the data that is being provided and to ensure that the data will be able to be used to perform the tracking analysis envisioned in the ALJ's June 16th reform order. The IPE will report on this effort on the Post-DPAG report.

Table 6-1: Suggested Definitions for Known Load Project Data Elements

Database Element	Definition
Unique Identifier	This should be a unique identifier associated with each known load. The identifier can be for a new load (no existing meter) or incremental load at an existing customer meter. Only one identifier should be used for each known load even if the load is expected to be served by multiple circuits.
Circuit	This is the name/ID for the circuit(s) that the new load is expected to be served by.
Sector (Type)	Residential, Commercial, Industrial or Agricultural
Customer Category	Information on customer category such as EV charger, cannabis cultivation, hospital, tract homes etc.
IEPR Status	Embedded or incremental (currently, incremental load only used by SCE).
Load Amount (MW)	This is the load (MW) expected during the peak load hour after adjustments, if any, are made to the load requested by customer. For a new load, this is the peak for the entire load. For an incremental load, it's the peak for just the increment of load requested by the customer. This value should be the same as the value used in the planning process.
Initial Service Request Date	This is the date on which the service request for a new load or incremental load at a customer meter was made. This is not the date that an existing customer first received service. This

	is the date on which the existing customer made a request for an incremental service.
Current Expected In-Service Date	This is the utility planned in-service date associated with the known load. In the case that the known load is an incremental load at an existing business, this date is the date at which service for this incremental load is expected to be provided.
Status	This is the status of the service request that is driving the known load which would be one of the following: in-service, ongoing or cancelled
Actual In-Service Date	This is the date on which the new or incremental service was provided.
Actual Load Amount	The usability of this data will be discussed with the IOUs and this data element will be modified as necessary.

6.2. Load Forecasting Comparison

In the 2021 IPE Report, made a comparison (Step 19 of the IPE Plan) of the 2020 peak load forecasts (included in the 2019 GNA) and 2020 actuals at the circuit level for a statistically meaningful number of circuits. This is a repeat of the process used in the previous cycle (also Step 19). Note that the verification of the comparison for SDG&E is included in Section 7.4.5. As discussed in this section, it would be more meaningful to perform this comparison using weather adjusted actual peak loads. The IPE plans to obtain actual 2021 loads adjusted to 1-in-10 from SDG&E and then repeat this analysis with these loads and report out the results in the Post-DPAG report.

6.3. Redaction of Data in Public Version of the IPE DPAG Report

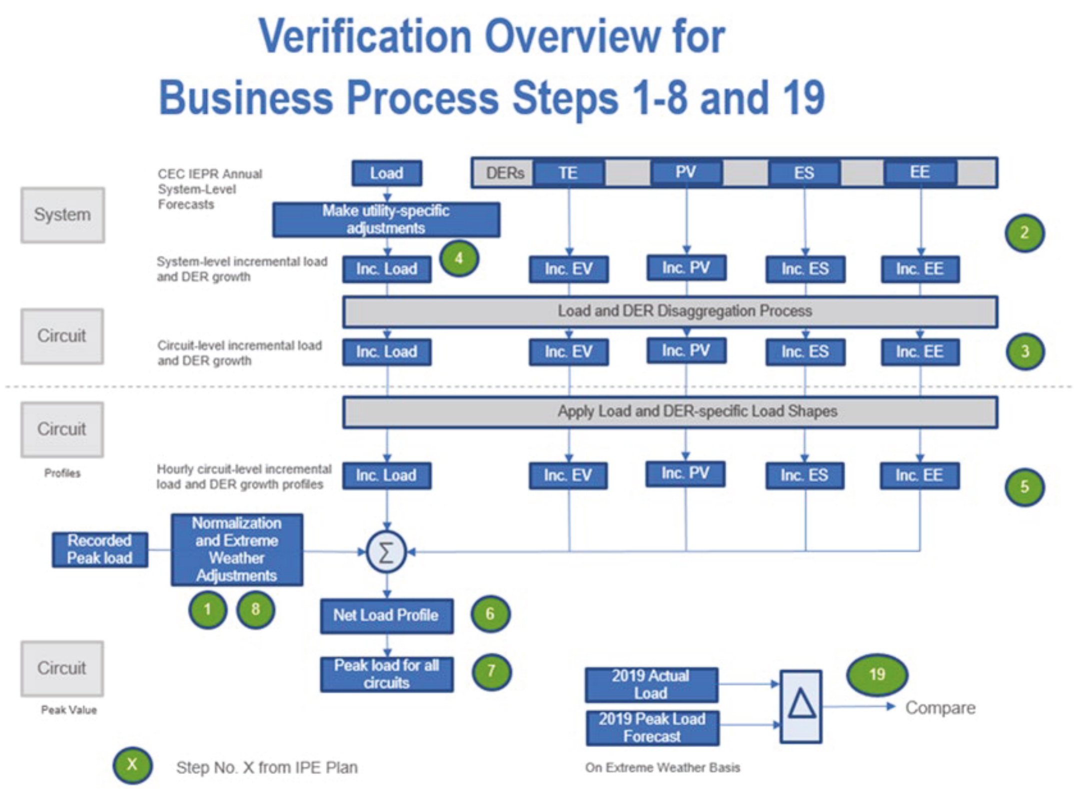
We observe that as a result of the request by SDG&E to treat some data in this report as confidential, the public version of this report will contain some figures and tables that are redacted. We recognize that this impacts the information that the public receives from the IPE report. We have tried to minimize the impact of redaction in the public report by providing both GNA and Facility IDs (which are public). We have also provided the results of our verification in a generic way without naming the circuit(s) on which the verification was performed.

7. Verification Approach and Results

The results of the step-by-step process verification process followed by the IPE is presented in this section. This verification review will follow the framework set out in the Final IPE Plan included in Appendix C. To a large extent, the verification process is same as the one performed for the previous cycle. Any differences from last year's process are discussed in this section.

The following graphic provides an overview of the Steps 1 through 8 and 19 in the review process.

Figure 7-1: Business Steps Overview



In order to perform the step-by-step verification, the IPE gathered circuit-level data for a number of representative circuits through data requests sent to SDG&E. These representative circuits were selected using the following criteria:

- Circuits from various regions within SDG&E
- Circuits where the historical data contains discrepancies such as gaps in SCADA data, temporary transfers, etc.
- Circuits that show how the historical peak data is adjusted for 1-in-2 weather
- Circuits with and without needs identified in the GNA

- Circuits with needs identified in the GNA that were solved by phase balancing and transfers
- Circuits with planned projects
- Circuits with candidate deferral opportunities

Table 7-1 shows which circuits were used in the various steps of the verification process. In this table, the facility code or pseudonym used for identifying the circuits are also provided.

Table 7-1: List of circuits used in the verification steps

Facility ID	Facility Code	Data discrepancies and temporary transfers	Peak load weather normalization	Known load additions	Load transfers and phase balancing	Planned projects	Steps verified
2022_0411	A	x	x				1
2022_1006[4]	B	x	x			x	1, 5-12
2022_0335	C	x	x			x	1, 5-12
2022_0493	D	x	x				1
2022_0208	E	x	x	x			1, 4
2022_0529	F	x	x				1
2022_0472	G	x	x				1
2022_0635	H	x	x				1
2022_0642	I	x	x				1
2022_0279	J				x		10
2022_0366	K				x		10
2022_0317	L				x		10
N/A[5]	M				x		10
2022_0477	N				x		10
2022_0561	O			x			4
2022_0183	P			x			4
2022_1005	Q					x	5-12

It should be noted that only circuit and bank level needs were verified through analysis of the detailed steps discussed below. Segment level capacity and voltage needs are determined using

[4] This facility received a known load request after the analysis was completed and captured as a new need.
[5] This facility is currently under construction as a part of a Reliability Substation Rebuild project and hence does not have a facility ID.

load flow analysis and in these cases demonstrations (walk-throughs) by SDG&E were used to verify these needs as discussed in the sections below.

7.1. PROCESSES TO DEVELOP SYSTEM LEVEL FORECASTS AT CIRCUIT LEVEL

7.1.1. Collect 2021 Actual Circuit Loading, Normalize and Adjust for Extreme Weather – Steps 1 and 8

Purpose: To verify the calculation of weather-normalized peak loads for a subset of circuits selected by the IPE; Perform validation of the process.

Process: SDG&E uses the 2021 actual circuit loading data from SCADA to develop the normalized 1-in-2 peak load for each circuit. First, SDG&E uses Integral Analytics SCADA Scrubber to remove any data errors and temporary load transfers. SDG&E Engineers then review scrubbed data and identify peak load for each circuit. Generation from largest single generator (or closely coupled generators) above 0.5MW are added back based on expected generation during the peak load hour. Finally, SDG&E uses an internal tool to develop 1-in-2 weather adjusted peak load for each circuit using the peak load from the scrubbed data.

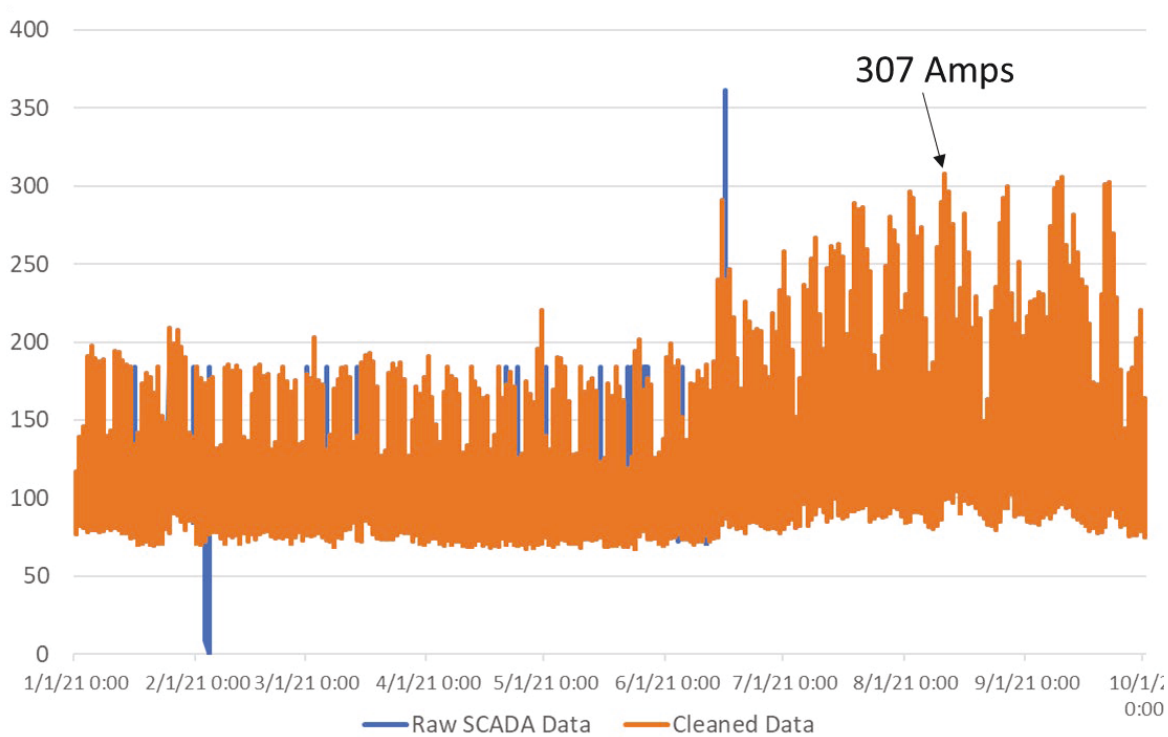
Verification: The IPE collected the observed peak load data for selected circuits that will be used in the verification of subsequent steps. This is shown in Table 7-2. This table also shows the equipment rating and the capacity with Alternate Service. SDG&E indicated that “Capacity with Alternate Service” is capacity contracted by a customer which needs to be available all the time. The loading on a circuit will be limited to the Alternate Service rating if it’s lower than the equipment rating.

Table 7-2: Scrubbed 2021 Peak Load and Rating for Select Circuits

Facility ID	Facility Code	Peak Load (Amps)	Peak Date and Time	Equipment Rating	Capacity w/Alt Service
2022_0411	A	[redacted]			
2022_1006	B	[redacted]			
2022_0335	C	[redacted]			
2022_0493	D	[redacted]			
2022_0208	E	[redacted]			
2022_0529	F	[redacted]			
2022_0472	G	[redacted]			
2022_0635	H	[redacted]			
2022_0642	I	[redacted]			

The IPE obtained the 2021 hourly raw SCADA data, as well as scrubbed data from SCADA Scrubber for all the circuits shown in Table 7-2. The raw and scrubbed data for one of the circuits is shown in Figure 7-2. In this figure the instances of data drops (missing data) can be seen in the raw SCADA data (blue). The scrubbed data is shown in orange. The peak of the scrubbed data matches with the value reported in Table 7-2 for this circuit.

Figure 7-2: Raw and Scrubbed Hourly Load (Amps) Profile for a Circuit



The IPE also verified the process used by SDG&E to normalize the peak load for 1-in-2 weather. The weather normalization is performed using average daily maximum temperature and Weighted Average Cooling Degree Days (WCDD) gathered over the last 16 years for this calculation. This is shown in Table 7-3.

Table 7-3: Weather Normalized Peak Loads for Select Circuits

Facility ID	Facility Code	Peak Loading from SCADA Scrubber (Amps)	Normalization Factor calculated by IPE	Normalized Peak Calculated by IPE (Amps)	Normalized Peak used in the GNA (Amps)
2022_0411	A	[redacted]	1.095	[redacted]	[redacted]
2022_1006	B	[redacted]	1.094	[redacted]	[redacted]
2022_0335	C	[redacted]	1.092	[redacted]	[redacted]
2022_0493	D	[redacted]	1.142	[redacted]	[redacted]
2022_0208	E	[redacted]	1.036	[redacted]	[redacted]
2022_0529	F	[redacted]	1.158	[redacted]	[redacted]
2022_0472	G	[redacted]	1.112	[redacted]	[redacted]
2022_0635	H	[redacted]	1.073	[redacted]	[redacted]
2022_0642	I	[redacted]	1.173	[redacted]	[redacted]

The scrubbed peak loads and the weather normalization factor (in the form of a multiplier) are then input to LoadSEER. LoadSEER uses this information, along with the hourly circuit loads for the last three years and hourly temperature data for the last thirty years to develop weather-adjusted (1-in-10 or P95) 576-hourly load profiles. The P95 profiles translates to a 1-in-10 probability load profile and P75 translates to 1-in-2.

7.1.2. Determine Load and DER Annual Growth on System Level- Step 2

Purpose: To verify the calculation of annual system level load and DER growth using the CEC IEPR system-level forecasts as the starting point.

Process: The process used by SDG&E for determining system level load and DER forecasts is summarized below.

- SDG&E used the peak load and energy forecasts from the "CED 2020 Load Modifiers – Mid Baseline Mid AAEE with CAISO with 2031" as the starting point for load and DER forecasts.
- SDG&E models the following DERs explicitly: EV, PV, Energy Storage, EE and LMDR. The forecasts for light and medium duty electric vehicles were obtained from CEC's "CEDU 2020 Hourly Forecast Update - SDGE - HIGH-LOW" forecast. The forecasts for residential PV, retail non-residential PV, energy efficiency and energy storage were obtained from CEC's "CEDU 2020 Hourly Forecast Update – SDGE – MID-LOW" forecast.
- SDG&E adjusts the IEPR peak load forecast for the following: transmission losses, other private generation and EVs. The adjusted forecast is used for determining the annual peak load growth at the system level.

- The annual peak load growth is then allocated to customer classes (residential, industrial, and commercial) proportional to their forecast annual energy consumption.
- Annual known load additions for each customer class are then subtracted from the annual peak load growth calculated in the previous step.
- The resultant system level growth forecast by customer classes is disaggregated to the circuit level using allocation factors discussed in Step 3.

Verification: The IPE obtained the following IEPR forecasts and performed the calculations as described above.

- CED 2020 Load Modifiers - Mid Baseline Mid AAEE with CAISO with 2031 forecast,
- CEDU 2020 Hourly Forecast Update - SDGE - HIGH-LOW forecast, and
- CEDU 2020 Hourly Forecast Update – SDGE – MID-LOW forecast

The annual load growth forecasts used by SDG&E to develop the needs in the GNA and verified by the IPE are provided in Table 7-4. This table also shows the DR forecasts that are used in the GNA. The annual forecasts for other DERs such as PV, energy storage, LDEV and MDHD EV are derived from the hourly forecast for these DERs developed by the CEC (CED 2019 Hourly Results - SDGE - MID-LOW case). These are discussed further in Section 7.1.3.

Table 7-5 shows the calculation of system-level loads to be disaggregated to the circuits after taking the Known Load growth into account which is shown on line 6. If the cumulative Known Load growth is greater than the cumulative IEPR load growth forecast, as is the case in 2022, 2023 and 2024 (negative number in row 11), the system-level load to be disaggregated to the circuit level is zero since the Known Loads are explicitly modeled. If the cumulative Known Load growth is less than the cumulative IEPR load growth forecast, as is the case in years 2025 and later, the difference between the two is developed for each customer class (DOM, COM and IND) as shown in rows 12, 13 and 14. If this difference is positive, i.e., IEPR load forecast is greater than known load for a class, this is the load that will be disaggregated by LoadSEER to all the circuits. If this difference is negative, then the net load growth across all classes will be disaggregated by LoadSEER to all the circuits. For example, the difference between the cumulative IEPR forecast and cumulative known load forecast for COM class in 2025 is -56.9 MW (row 13). Therefore, a net load forecast of 16.9 MW (73.9-56.9) is calculated for the DOM class, which will then be used by LoadSEER to disaggregate to all circuits. Due to the methodology used by SDG&E, the loads in the initial years (2022-2025) are higher than CEC's forecast due to higher amounts of known loads. However, CEC's incremental load forecast for 2026 is adjusted such that cumulative SDG&E forecast for that year and the following years are same as the CEC cumulative growth forecast.

Table 7-4: Developing Annual System-level Load and DER forecasts from CEC IEPR forecast

SDGE TAC Peak and Energy Forecasts: CED 2020 Forecast, Mid Baseline-Mid AAEE

Coincident Peak 1 in 2 (MW)			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	Peak End Use Consumption (traditional baseline end use load plus electrification and climate change impacts)		4508	4560	4595	4667	4722	4774	4836	4879	4930	4980	5031
2		1 Includes LDEVs	42	58	74	89	102	112	120	129	137	145	154
3		1 Includes Electric Busses	0	1	1	1	1	1	1	1	2	3	3
4		1 Includes Other Medium/Heavy-Duty EVs	1	1	3	4	5	6	8	10	13	16	19
5		1 Includes Other Electrification	3	4	6	8	10	12	15	17	19	20	22
6		1 Includes Incremental Climate Change Impacts	11	17	22	27	33	39	45	51	57	63	69
7	Estimated Losses		282	278	274	274	273	272	273	273	274	275	275
8	Gross Generation for Peak End Use Consumption (1 plus 7)		4790	4838	4870	4941	4995	5047	5109	5152	5204	5255	5307
9	Self-Generation Corresponding to Peak End Use Consumption		1158	1262	1352	1433	1505	1570	1626	1677	1723	1766	1806
10		9 Includes Photovoltaic	1055	1160	1250	1333	1406	1471	1528	1580	1627	1670	1711
11		9 Includes Other Private Generation	103	102	101	100	99	98	97	96	95	95	94
12		9 includes Storage	0	0	0	0	1	1	1	1	1	1	1
13	Load-Modifying Demand Response		16	17	17	17	17	18	18	18	18	18	18
14		13 Includes Non-Event DR	0	0	0	0	0	0	0	0	0	0	0
15		13 Includes Event-Based DR	16	17	17	17	17	18	18	18	18	18	18
16	Baseline Net Load Corresponding to Peak End Consumption (8 minus 9 minus 13)*		3720	3672	3620	3616	3603	3595	3606	3601	3610	3622	3634
17	Peak Shift Impact, Baseline Forecast		489	580	658	720	775	821	861	892	919	943	966
18	*Baseline Net System Peak (16 plus 17)*		4209	4252	4278	4337	4378	4416	4467	4493	4529	4565	4601
19	AAEE Savings Corresponding to Peak End Use Consumption (plus losses)		52	73	103	134	164	193	221	250	278	306	336
20	*** AAPV is embedded in the baseline CED 2019 forecast (10) ***												
21	Managed Net Load Corresponding to Peak End Consumption (16 minus 19)*		3668	3599	3517	3483	3440	3403	3385	3352	3333	3317	3298
22	Peak Shift Impact, Managed Forecast		498	593	678	747	808	861	908	945	979	1010	1043
23	*Managed Net System Peak (21 plus 22)*		4166	4192	4195	4230	4248	4263	4293	4297	4312	4326	4341

Incrimental DERs	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
13 Includes Event-Based DR	16	1.27	0.48	0.05	0.06	0.12	0.13	0.22	0.29	0.00	0.00
Years to disaggregate											
Total Load		34	16	57	41	41	53	32	41	40	39

Incremental Load growth to disaggregate by class	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
DOM		0.0	0.0	0.0	17.0	33.3	49.9	31.2	39.7	26.8	23.4
COM		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.4	14.0
IND		0.0	0.0	0.0	5.5	1.5	2.0	1.2	1.5	1.5	1.4
Years to disaggregate											

			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
3		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
4		[illegible]	[illegible]	[illegible]	[illegible]	5	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
5												
6	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
7		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
8		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
9		[illegible]	0	0	0	0	0	0	0	0	0	0
[illegible]												
1	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
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7.1.3. Disaggregate Load and DER Annual Growth to Circuit Level –Step 3

Purpose: To verify that the sum of the disaggregated loads and DERs match the CEC system level values (verification for Step 3a) and that the disaggregated loads and DER capacities are used to develop their respective profiles in Step 5 (verification for Step 3).

Process: A high-level summary of SDG&E's load & DER disaggregation process is given below.

Load disaggregation

SDG&E uses Integral Analytics LoadSEER software to score each acre in SDG&E's territory for the likelihood of increased load by customer class. SDG&E then allocates the customer class load growth projections (verified in Step 2) to each parcel based on the ratio of the parcel score to the total score and maps the load growth to circuits based on closest proximity. Results are then reviewed by local planning engineers with specialized knowledge of local areas.

DER Disaggregation

SDG&E disaggregates system-level growth forecasts (verified in Step 2) down to the circuit level for the following five DERs: Additional Achievable Energy efficiency (AAEE), Photovoltaics (PV), Energy Storage (ES), Electric Vehicles (EV), and Load Modifying Demand Response (LMDR). The system-level incremental MW capacity by DER technology type is allocated to the circuits based on methodologies specific to each DER type. Variables used to allocate incremental DER capacity geospatially include consumption by customer class, historical PV adoption by zip code, the s-curve trending model, weather zones, and many other factors specific to each type of DER. The DER disaggregation process is described in detail in Appendix 3 of the GNA report.

Verification: The IPE obtained circuit-level load and DER growth forecasts for all circuits from SDG&E[6]. We then performed a check to see if the sum of the circuit level forecasts for load and each DER matched with the corresponding system-level values verified in Step 2. Tables 7-6 to 7-11 show the results of the verifications performed. The results show that the sum of circuit level forecasts match with the corresponding system-level values for both load and DERs. For LMDR the sum of circuit level forecasts is slightly different from the system-level values, but the magnitude of the difference is very small and unlikely to have any impact on the results.

Table 7-6: Load growth forecast verification at the feeder level

System-level load growth forecast from CEC (MW)										
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Residential	0.00	0.00	0.00	16.99	50.34	100.24	131.41	171.15	197.95	221.37
Commercial	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.42	25.39

[6] The IPE's comparison included the years 2022 to 2030 and not 2031 since the files provided by SDG&E were missing the data for that year.

Industrial	0.00	0.00	0.00	5.55	7.07	9.04	10.25	11.79	13.27	14.72
Total	0.00	0.00	0.00	22.54	57.41	109.28	141.66	182.94	222.64	261.49
Sum of circuit-level load growth forecast calculated by the IPE (MW)										
Residential	0.00	0.00	0.00	16.99	50.34	100.24	131.41	171.15	197.95	221.37
Commercial	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.42	25.39
Industrial	0.00	0.00	0.00	5.55	7.07	9.04	10.25	11.79	13.27	14.72
Total	0.00	0.00	0.00	22.54	57.41	109.28	141.66	182.94	222.64	261.49

Table 7-7: EE growth forecast verification at the feeder level

System-level EE growth forecast from CEC (MW)									
	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	6.39	7.07	7.19	7.19	6.73	6.73	7.01	6.86	6.91
Commercial	7.23	8.00	8.14	8.14	7.62	7.62	7.94	7.77	7.82
Industrial	0.44	0.49	0.50	0.50	0.47	0.47	0.48	0.47	0.48
Total	14.06	15.57	15.83	15.83	14.82	14.81	15.44	15.11	15.20
Sum of circuit-level EE growth forecast calculated by the IPE (MW)									
Residential	6.39	7.07	7.19	7.19	6.73	6.73	7.01	6.86	6.91
Commercial	7.23	8.00	8.14	8.14	7.62	7.62	7.94	7.77	7.82
Industrial	0.44	0.49	0.50	0.50	0.47	0.47	0.48	0.47	0.48
Total	14.06	15.57	15.83	15.83	14.82	14.81	15.44	15.11	15.20

Table 7-8: ES growth forecast verification at the feeder level

System-level ES growth forecast from CEC (MW)									
	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total	12.03	12.59	13.15	13.67	14.13	14.52	14.86	15.15	15.41
Sum of circuit-level ES growth forecast calculated by the IPE (MW)									
Residential	8.50	8.99	9.53	9.99	10.37	10.68	10.93	11.14	11.34
Commercial	3.52	3.60	3.62	3.68	3.75	3.84	3.93	4.01	4.07
Total	12.03	12.59	13.15	13.67	14.13	14.52	14.86	15.15	15.41

Table 7-9: PV growth forecast verification at the feeder level

System-level PV growth forecast from CEC (MW)									
	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total	147.79	122.86	112.97	100.66	89.25	79.17	71.15	64.23	59.17
Sum of circuit-level PV growth forecast calculated by the IPE (MW)									
Residential	94.59	68.06	61.03	53.92	47.63	42.14	37.72	33.84	30.96
Commercial	53.20	54.81	51.94	46.73	41.62	37.02	33.43	30.40	28.21
Total	147.79	122.86	112.97	100.65	89.25	79.17	71.15	64.23	59.17

Table 7-10: EV growth forecast verification at the feeder level

System-level EV growth forecast from CEC (MW)									
	2022	2023	2024	2025	2026	2027	2028	2029	2030
MHDEV	1.45	2.53	1.58	1.90	2.68	3.23	4.03	4.93	5.72
LDEV	40.09	27.41	28.27	40.33	47.63	21.70	5.79	8.66	16.33
Sum of circuit-level EV growth forecast calculated by the IPE (MW)									
MHDEV	1.45	2.53	1.58	1.90	2.68	3.23	4.03	4.93	5.72
LDEV	40.09	27.40	28.27	40.33	47.63	21.70	5.79	8.66	16.33

Table 7-11: LMDR growth forecast verification at the feeder level

System-level LMDR growth forecast from CEC (MW)									
	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total	1.27	0.48	0.05	0.06	0.12	0.13	0.22	0.29	0.00
Sum of circuit-level LMDR growth forecast calculated by the IPE (MW)									
Residential	0.23	0.19	0.02	0.31	0.30	0.28	0.23	0.13	0.00
Commercial	1.04	0.29	0.03	0.51	0.46	0.36	0.28	0.16	0.00
Total	1.27	0.48	0.05	0.82	0.76	0.64	0.51	0.29	0.00

7.1.4. Add Incremental Load Growth Projects to Circuit Level Forecasts (those loads not in CEC forecast) – Step 4

Purpose: To verify the process used by SDG&E for handling known load additions in load forecasting process.

Process: Known load additions could be embedded in the CEC forecast or incremental to the CEC forecast. SDG&E does not have any loads that it considers to be “incremental” (as that term is used by SCE). Embedded known loads are subtracted from the CEC forecast in coming up with the system-level forecasts that are allocated to the circuits as verified in Step 2. Examples of known loads are given below:

- New Commercial: Business, Transportation, Hospitals, Parking, Military and Farming
- New Residential: Home construction
- New Industrial: Manufacturing and Chemical Processing

Verification: The IPE gathered known load additions by customer class at the circuit level, which are shown in Table 7-12. We then compared the cumulative circuit-level load by customer class with the system-level values used in Step 2. These values matched exactly.

Table 7-12: Known load additions by customer class

	2022	2023	2024	2025	2026
New Commercial	82.44	16.71	1.77	9.58	6.13
New Residential	12.48	0.38	2.38	0.48	
Total	94.92	17.08	4.15	10.06	6.13

7.1.5. Convert Peak Growth to 576 Profile, Determine Peak Load – Steps 5, 6 and 7

Purpose: To verify that 576 hourly profiles for peak load growth, DER growth and base load forecast obtained from LoadSEER correspond to the peak load growth, DER growth and base load forecasts verified in Step 2 for select circuits.

Process: Below is a high-level summary of the process that SDG&E uses to develop 576-hourly profiles for base load, load growth and DER growth.

Peak load growth 576 hourly profile

SDG&E uses the circuit-level peak load growth forecast by customer class (verified in Step 3) and standard 576-hourly profiles for each customer class to develop the Peak load growth 576 hourly profile for each circuit for each forecast year. This is done using LoadSEER which calculates the 576-hourly load growth profiles at different percentile levels such as P5, P25, P75, and P95.

DER growth 576 hourly profile

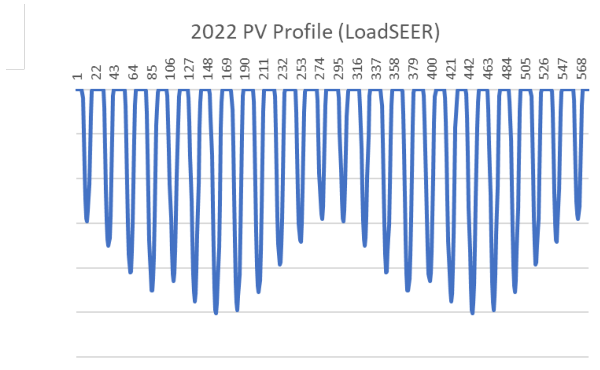
SDG&E uses the circuit-level DER growth forecast by customer class (if applicable) and standard 576-hourly profile for each DER to develop the DER growth 576 hourly profile for each circuit for each forecast year.

Base load 576 hourly profile

LoadSEER is also used to develop 576-hourly profiles for base load at different percentile levels such as P5, P25, P75, and P95. LoadSEER used the last three years of hourly load data for each circuit and thirty years of hourly weather data to develop these profiles.

Verification: The IPE obtained the 576 hourly base load, load growth and DER growth profile from LoadSEER for several circuits as shown in Table 7-1. The IPE also obtained standard load profiles for new loads by customer class and various DERs by customer class, as applicable. We then used the peak load and DER forecast at the circuit level (verified in Step 3) and the standard profiles to develop 576 hourly profiles and compared it with those from LoadSEER. Figure 7-3 to Figure 7-8 show the comparison of the 576 profiles from LoadSEER and those calculated by the IPE for PV, EV, ES, EE, economic load growth, and known load addition for a circuit. In these figures, the upper plot shows the results from LoadSEER and the lower plot shows the values calculated by the IPE drawn using the same scale. The actual values are not provided due to their confidential nature. It can be observed from these figures that the 576 profiles calculated by the IPE match very closely with those obtained from LoadSEER. It should be noted that a direct comparison of the base load profile calculated by LoadSEER was not possible since the software employs proprietary algorithms, using several years of historical data, to determine this profile.

7-3


2022 PV Profile (LoadSEER)
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22
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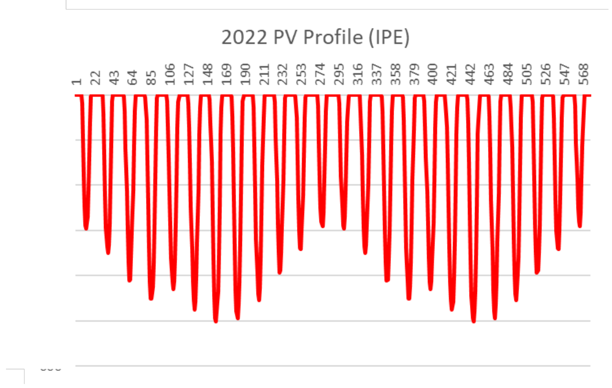
2022 PV Profile (IPE)
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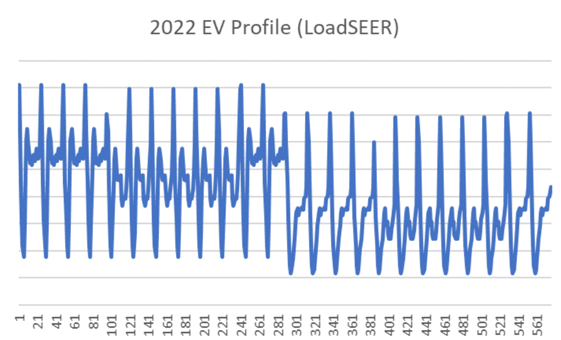
7-4


2022 EV Profile (LoadSEER)
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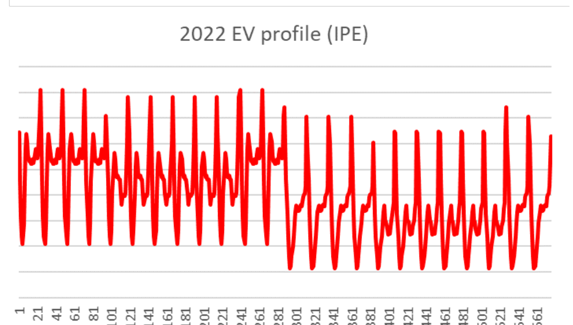
2022 EV profile (IPE)
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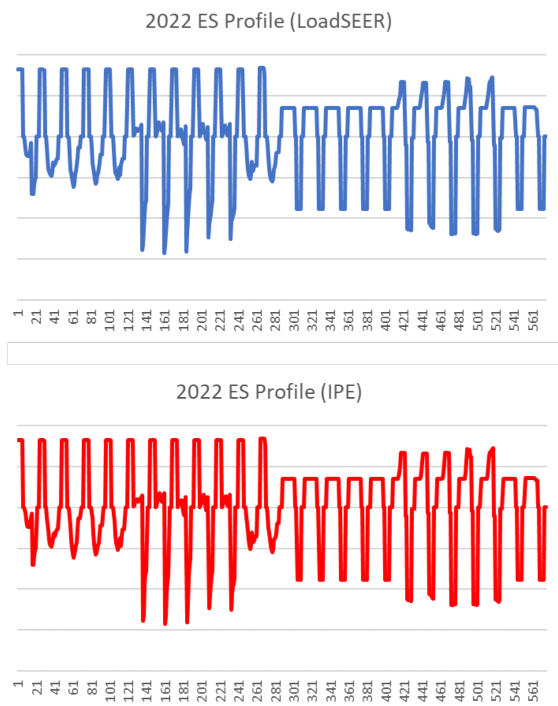
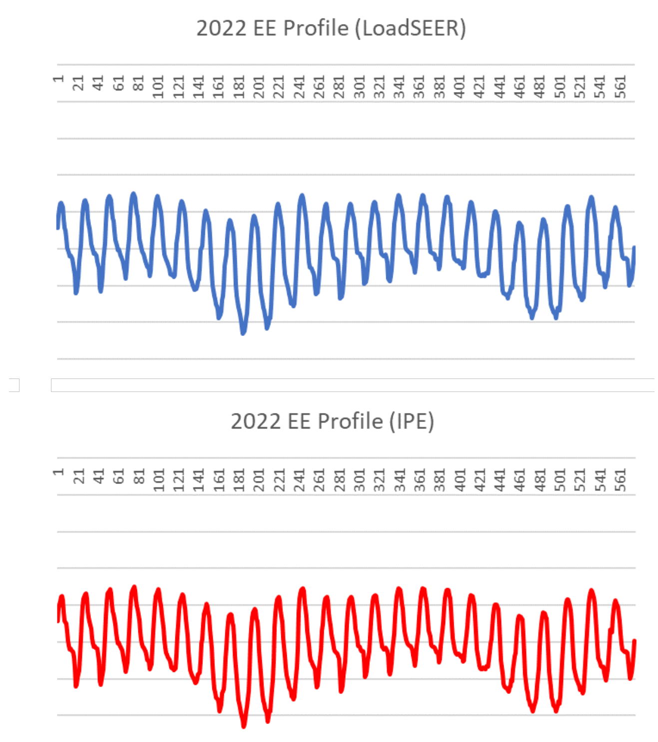
7-5


2022 ES Profile (LoadSEER)
1 21 41 61 81 101 121 141 161 181 201 221 241 261 281 301 321 341 361 381 401 421 441 461 481 501 521 541 561
2022 ES Profile (IPE)
1 21 41 61 81 101 121 141 161 181 201 221 241 261 281 301 321 341 361 381 401 421 441 461 481 501 521 541 561

7-6


2022 EE Profile (LoadSEER)
1 21 41 61 81 101 121 141 161 181 201 221 241 261 281 301 321 341 361 381 401 421 441 461 481 501 521 541 561
2022 EE Profile (IPE)
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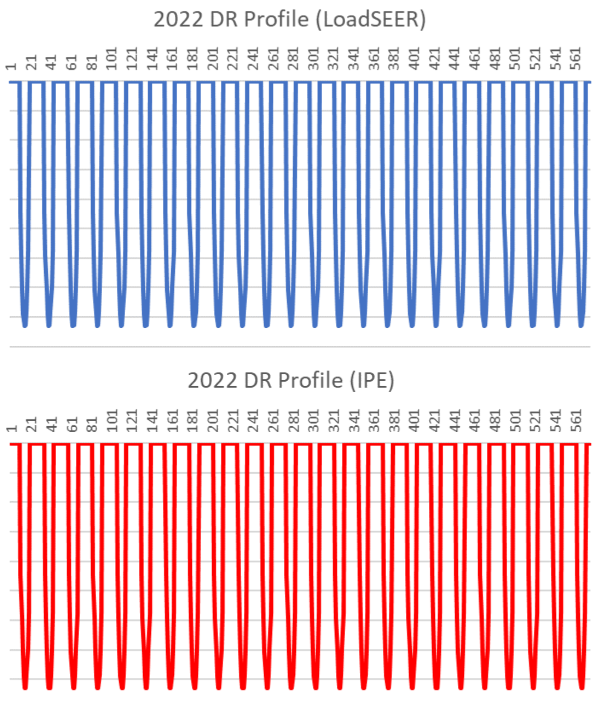
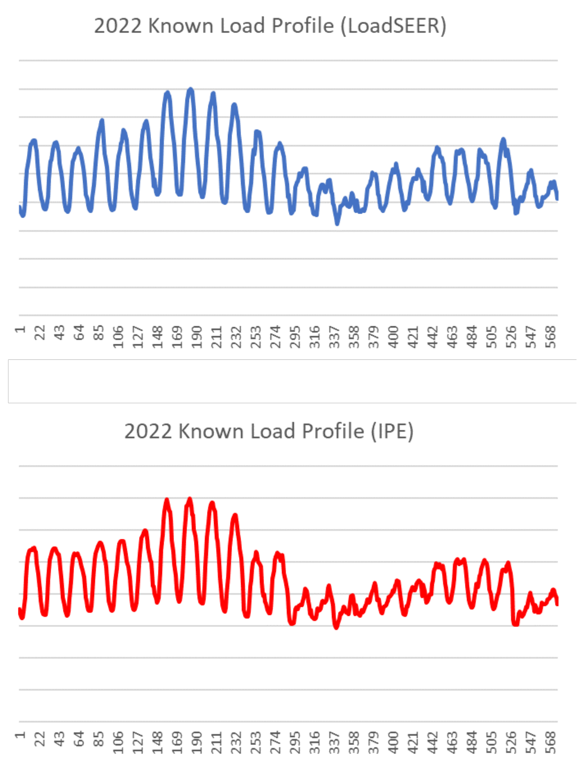
7-7

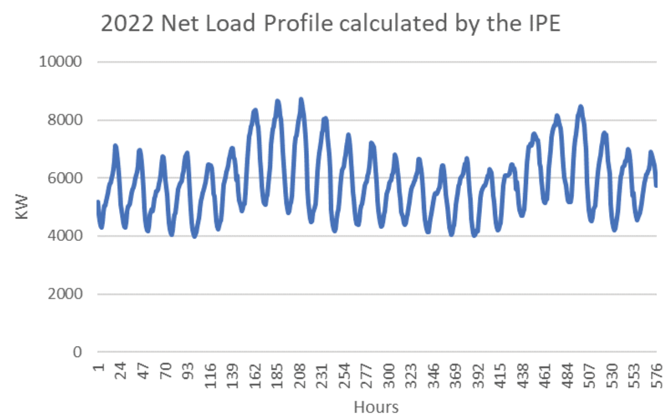

2022 DR Profile (LoadSEER)
1 21 41 61 81 101 121 141 161 181 201 221 241 261 281 301 321 341 361 381 401 421 441 461 481 501 521 541 561
2022 DR Profile (IPE)
1 21 41 61 81 101 121 141 161 181 201 221 241 261 281 301 321 341 361 381 401 421 441 461 481 501 521 541 561

7-8


2022 Known Load Profile (LoadSEER)
1 22 43 64 85 106 127 148 169 190 211 232 253 274 295 316 337 358 379 400 421 442 463 484 505 526 547 568
2022 Known Load Profile (IPE)
1 22 43 64 85 106 127 148 169 190 211 232 253 274 295 316 337 358 379 400 421 442 463 484 505 526 547 568

The IPE then derived the net load profile using the components mentioned above. The calculated net load profile matched with the one from LoadSEER. Figure 7-9 shows the net load profile for the circuit calculated by the IPE.

Figure 7-9: Net load 576-Hourly Load Profile (KW) for a sample circuit



The IPE then determined the net peak load (and net peak load hour) using the 576 hourly load profiles for a few circuits. From these load profiles, the peak load and the peak load hour were obtained as shown in Table 7-13. Information beyond the 5-year planning period is confidential for circuits other than the ones that are CDOs.

Table 7-13: Peak load (KW) for select circuits

Facility ID	2022_0411	2022_1006	2022_0335	2022_0493	2022_0208
Year	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	10,236	10,993	8,708	9,100	10,187
2023	12,187	10,923	9,573	9,122	8,966
2024	12,054	10,431	10,636	9,144	8,898
2025	13,564	10,373	10,662	9,191	8,950
2026	14,123	10,307	10,758	9,273	8,938
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

7.2. PROCESSES TO DETERMINE CIRCUIT NEEDS AND DEVELOP GNA

7.2.1. Initial Comparison to Equipment Ratings, Evaluate No Cost Solutions and Comparison to Equipment Ratings after No Cost Solutions – Steps 9, 10 and 11

Purpose: To verify the overloads calculated by SDG&E for circuits prior to load transfers, phase balancing etc.

Process: SDG&E compares the peak load determined in Step 7 against the rating of the circuit to determine any overloads at the circuit and bank level. It should be noted that this verification process is used for thermal overloads (capacity needs) on circuits and banks only.

Verification: The IPE used the peak loads for selected circuits from Step 7 and the maximum capacity of those circuits to determine the overload. The maximum capacity is the actual equipment rating, but in some cases the capacity is limited to a value that is lower than the equipment rating for providing alternate service. Table 7-14 shows the overloads that were calculated for each circuit. The overload is calculated as the loading above the capacity with alternate service expressed as a percentage of the equipment rating.

Table 7-14: Overloads calculated for selected circuits

Facility ID	2022_0411		2022_1006		2022_0335		2022_0493		2022_0208	
Equipment Rating (KW)	[redacted]		[redacted]		[redacted]		[redacted]		[redacted]	
	Peak Load (KW)	Over-load (%)	Peak Load (KW)	Over-load (%)	Peak Load (KW)	Over-load (%)	Peak Load (KW)	Over-load (%)	Peak Load (KW)	Over-load (%)
2022	10,236	82%	10,993	106%	8,708	84%	9,100	88%	10,187	82%
2023	12,187	98%	10,923	105%	9,573	92%	9,122	88%	8,966	72%
2024	12,054	97%	10,431	100%	10,636	102%	9,144	88%	8,898	71%
2025	13,564	109%	10,373	100%	10,662	103%	9,191	88%	8,950	72%
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

STEP 10: Incorporate load transfers, phase transfers, correct data deficiencies

Purpose: To verify the process used to incorporate load transfers, phase transfers, correct data errors.

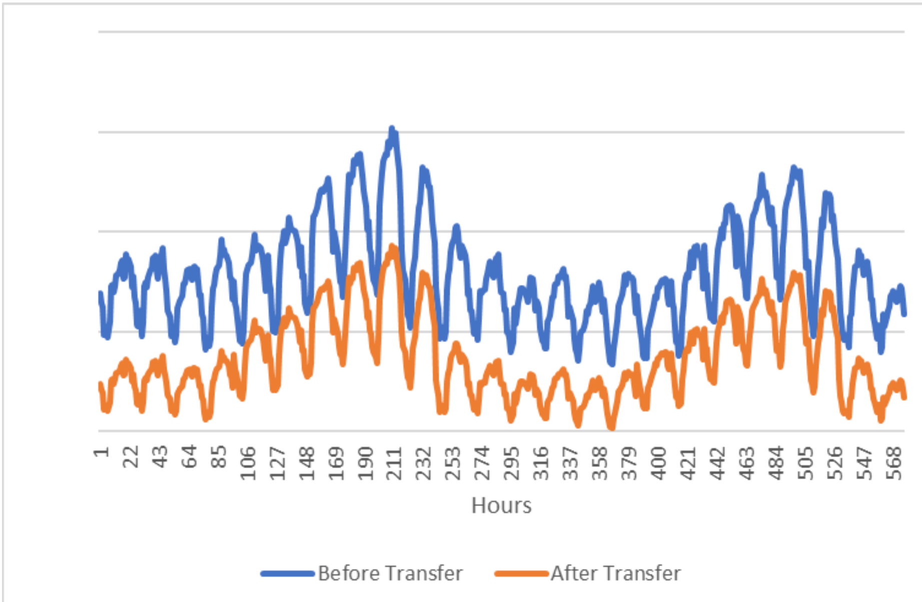
Process: SDG&E employs planned load transfers and switching operations which are typically the lowest cost options to address an identified need as they utilize existing capacity on distribution circuits. The GNA report identified 6 needs that were addressed using planned transfers and one need that was addressed by phase balancing.

Verification: The IPE obtained the 576 hourly load profiles from LoadSEER for the circuit the load is transferred from, as well the circuit it is transferred to, in order to verify that both circuits are below their capacities for the four transfers reported in the GNA.

Table 7-15 shows the facility IDs for the circuits that the load is transferred from and to and Figures 7-10 and 7-11 show the 576-hourly loads for the sending and receiving circuits for one of the transfers. By comparing the loading on the "Transfer to" and "Transfer from" circuits in these figures, it can be seen that the amount of load picked up by the "Transfer to" circuit is the same as the load removed from the "Transfer from" circuits.

Table 7-15: Load Transfers in 2020 GNA

GNA_ID (From Circuit)	Facility ID (From Circuit)	Facility ID (To Circuit)	MW Transferred	Transfer Date
GNA_2022_0013	2022_1003	New Circuit	[redacted]	6/1/2024
GNA_2022_0015	2022_1002	2022_0366	[redacted]	6/1/2023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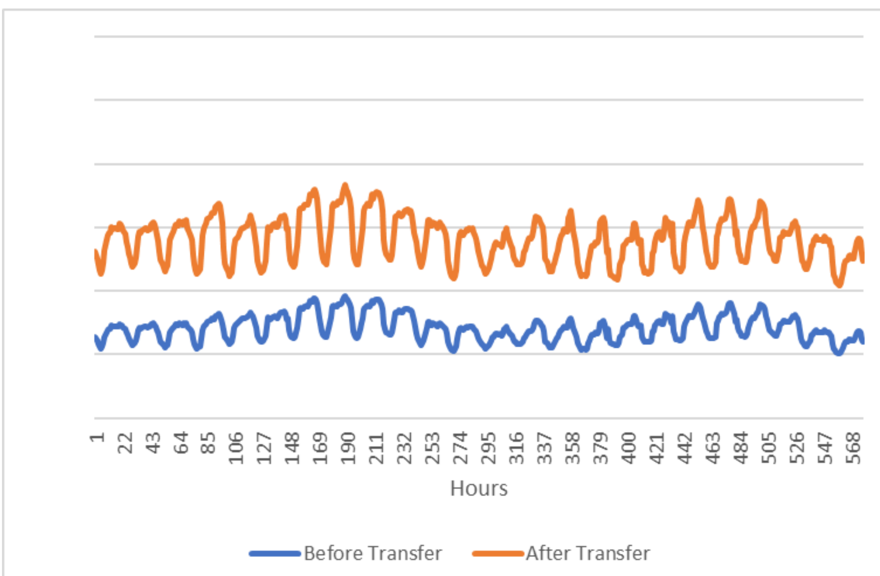
Hours
Before Transfer
After Transfer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568
Hours
Before Transfer
After Transfer

Verification: As discussed earlier, 2 of the 22 needs were solved using load transfers. Step 10 verified the loading on the transferred "from" and "to" circuits associated with these transfers. These transfers resulted in maintaining the peak loads on all the circuits within their limits. The remaining 20 needs are addressed through planned projects with are verified in the next steps.

7.2.2. Compile GNA Tables Showing Need and Timing – Step 12

Purpose: To verify that the projects in the GNA tables showing need amount and need timing match with the amounts and timing determined through earlier steps.

Verification: The IPE compared the needs for the selected circuits verified in Step 9 with those reported in the GNA. As shown in Table 7-16, the overloads calculated by the IPE match exactly with those reported in the GNA report.

Table 7-16: Verification of the overloads in the GNA for select circuits

Facility ID	2022_0411		2022_1006*		2022_0335		2022_0493		2022_0208	
	Overload calc by IPE (%)	Overload in GNA (%)	Overload calc by IPE (%)	Overload in GNA (%)	Overload calc by IPE (%)	Overload in GNA (%)	Overload calc by IPE (%)	Overload in GNA (%)	Overload calc by IPE (%)	Overload in GNA (%)
2021	82%	82%	106%	106%	84%	84%	88%	88%	82%	82%
2022	98%	98%	105%	105%	92%	92%	88%	88%	72%	72%
2023	97%	97%	100%	100%	102%	102%	88%	88%	71%	71%
2024	109%	109%	100%	100%	103%	103%	88%	88%	72%	72%
2025	113%	113%	99%	99%	104%	104%	89%	89%	72%	72%

7.3. PROCESSES TO DEVELOP PLANNED INVESTMENTS AND COSTS

7.3.1. Develop Recommended Solution – Step 13

Purpose: To verify the process used by SDGE in developing the planned investment for selected projects.

Process: The planning process involves reviewing circuit characteristics, such as phase imbalance, timing of need, available circuit ties, nearby circuits with available capacity, reactive power flow, and the relative ease with which new infrastructure could be built. SDG&E's distribution planning engineers analyze these aspects, among others, to determine a least cost, best fit and just-in-time solution to mitigate the problem.

7.3.2. Estimate Capital Cost for Candidate Deferral Projects – Step 14

Purpose: To verify the project costs provided by SDG&E against other sources such as rate case filings. To verify the total project level costs provided by SDG&E with those included in the DDOR.

Background: Capital cost estimates are made and revised throughout the life of a project. Initially, cost estimates are made when a project is first envisioned (i.e., as a result of a need determined in the planning process), and the estimate is used for overall budgeting purposes. This estimate most likely is a projection of costs for a project that will be implemented several years into the future. In the case of the GNA/DDOR, the projects of most interest are those that pass the timing screen which means projects that are 3-5 years in the future. At the initial planning/budgeting state the functional needs of the project (add a new circuit, add a new bank, add a line extension, add voltage control equipment, etc.) are known but normally no engineering of the solution has been done. As time progresses, and the project moves through additional stages of development, the cost estimates are updated based upon detailed site-specific needs and further defined engineering solutions. The final cost estimates are normally developed prior to final approval of the project—well before project construction begins. These final cost estimates include a very detailed breakdown of equipment cost components (wire, breakers, transformers, bus work, conductor costs, conduit, metering, and protection etc.), labor/contracting costs (civil foundation work, excavation, soil removal, trenching, etc.) and overheads (project management, contingency, etc.).

According to the American Association of Cost Engineers (AACE) cost estimating classification system, initial cost estimate accuracy would fall into the Class Five (-50% to +100%) or Class Four (-15% to +50%) range. Thus, for projects that are in the early stages of development the overall accuracy of the estimate is expected to be about -30% to + 70% of the final cost estimate/actual costs of the project.

Verification: SDG&E provided project-level cost breakdowns for 13 planned projects (except the four microgrid projects). They also provided the direct material and labor costs by equipment for each project. Table 7-17 and Table 7-18 show the project level and equipment level costs for one planned project (DDOR_2022_0012). The direct material and labor costs calculated from the equipment level table matches with those at the project level as seen in the tables.

Table 7-17: Project-level cost estimate for DDOR_2022_0012

	Direct Cost ($)	Indirect Cost ($)	Total ($)
Company Labor	[redacted]	[redacted]	[redacted]
Material	[redacted]	[redacted]	[redacted]
Other Charges	[redacted]	[redacted]	[redacted]
Contract Costs	[redacted]	[redacted]	[redacted]
AFUDC	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	736,139

Table 7-18: Equipment and labor costs for DDOR_2022_0012

Description	Unit	Quantity	Overtime %	Direct Material ($)	Direct Company Labor ($)	Other Direct Charges ($)	Direct Contract Costs ($)
Capacitor(s)	EA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cable & Connection	FT	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Switch(es)	EA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
TOTAL		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

7.4. PROCESSES TO DEVELOP CANDIDATE DEFFERAL LIST AND PRIORITIZE

7.4.1. Development of Candidate Deferral Projects – Step 15

Purpose: To develop a list of Candidate Deferral Opportunities and verify that this list matches the results SDG&E included in its DDOR.

Process: SDG&E applies two screens: a technical screen and a timing screen. The purpose of the Technical Screen is to identify the distribution services DERs can provide to potentially defer a distribution project, and whether there are any technical limitations associated with the ability of DERs to defer planned distribution projects. The purpose of the Timing Screen is to ensure cost-effective DER solutions can be procured with sufficient time to fully deploy and begin commercial operation in advance of the forecast need date. Three years (by Year Four), i.e., year 2025, is the earliest year considered adequate to successfully procure, contract, design, develop, market, and deploy DER solutions to address the identified distribution needs. There were two projects that require new capital investment in 2025 and these two projects passed the timing screen.

Verification: The IPE gathered the list of planned projects and their projected in-service dates as shown in Table 7-19 and verified that SDG&E had applied the timing screen correctly. As mentioned before, none of the projects pass the timing screen since the in-service date for the projects are within the first three years of the five-year planning horizon.

Table 7-19: Planned projects with in-service dates

GNA ID	DDOR ID	Facility ID	In-Service Date
GNA_2022_0001	DDOR_2022_0001	2022_0335	6/1/2024
GNA_2022_0002	DDOR_2022_0002	2022_0853	6/1/2024
GNA_2022_0003	DDOR_2022_0003	2022_0869	6/1/2024
GNA_2022_0004	DDOR_2022_0004	2022_0948	6/1/2023
GNA_2022_0005	DDOR_2022_0005	2022_0995	6/1/2023
GNA_2022_0006	DDOR_2022_0006	2022_0996	6/1/2023
GNA_2022_0008	DDOR_2022_0007	2022_0998	6/1/2023
GNA_2022_0009	DDOR_2022_0008	2022_0999	6/1/2023
GNA_2022_0010	DDOR_2022_0009	2022_1000	6/1/2023
GNA_2022_0011	DDOR_2022_0010	2022_1001	6/1/2023
GNA_2022_0014	DDOR_2022_0011	2022_1004	6/1/2023
GNA_2022_0015	DDOR_2022_0012	2022_1005	3/1/2023
GNA_2022_0016	DDOR_2022_0013	2022_1006	6/1/2024
GNA_2022_0017	DDOR_2022_0014	2022_1007	8/1/2023
GNA_2022_0018	DDOR_2022_0015	2022_1008	8/1/2023
GNA_2022_0019	DDOR_2022_0016	2022_1009	8/1/2023
GNA_2022_0020	DDOR_2022_0017	2022_1010	8/1/2023

7.4.2. Development of Operational Requirements – Step 16

Purpose: To confirm operational requirements for selected circuits are developed using the process described and that the values developed are the same as included in subsequent steps of the process (DDOR and DPAG).

Verification: The operational requirements for the CDO recommended in this DIDF cycle is virtually the same as was calculated in the prior DIDF cycle. Accordingly, for the current cycle, SDG&E elected to use the operational requirements calculated in the prior cycle. Additional information on the verification of operational requirements can be found in the 2021 IPE DPAG report.

7.4.3. Prioritization of Candidate Deferral Projects into Tiers – Step 17

Purpose: To verify that prioritization process used by SDG&E is consistent with the description of the description of the prioritization metrics, components, and tier ranking process.

Process: SDG&E prioritized and ranked the projects based on the categories of Cost Effectiveness, Forecast Certainty, and Market Assessment using the Joint Prioritization Workbook Template developed by the IOUs. These metrics are already described in Section 5 of this report.

Verification: SDG&E provided the Joint Prioritization Workbook Template as Appendix B to the DDOR report as required by DIDF Reform #22 of the May 20 ruling. Because the template is set up for ranking and tiering multiple CDOs, and since there is only one CDO that is available for potential deferral in this DIDF cycle, some of the entries in the template cannot be populated.

7.4.4. Calculate LNBA Ranges and Values – Step 18

The Locational Net Benefits Analysis (LNBA) value is the net present value (NPV) of the annual costs that are avoided by deferring a planned distribution project. The annual cost savings of deferral is the difference in revenue requirements between installing the project on (i) its planned in-service date, and (ii) a later date. These savings reflect the differences in annualized capital recovery costs and annual operations and maintenance (O&M) costs. The LNBA value can be expressed in a number of ways – as an absolute present value of the savings ($), as a levelized annual savings ($/yr) or as the levelized annual savings in relation to the amount of need (e.g., the kW overload) that the planned distribution project mitigates ($/kW-year). For a thermal overload, the amount of need is the maximum overload amount during the deferral period. The deferral periods used for the LNBA calculations depend on the planned distribution upgrade's in-service date, the horizon over which the revenue requirements are considered, and varies by the type of upgrade. The LNBA value is used as an indicator of the economic feasibility of a non-wires solution. A planned distribution project with a higher LNBA value would indicate, in general, that it is a more economically feasible for DERs to defer the planned distribution project as compared to planned distribution projects that have lower LNBA values. In the DDOR report, the LNBA values may be expressed in ranges, for example values may be in one of the following ranges $0-$100, $1---$500, >$500.

Methodology

We reviewed the methodology that SDG&E used to develop the LNBA values that it included in its DDOR Report. A summary of that review follows.

Deferral Timeframe

7-3 :

Project Type	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Pre- and Post-Application projects, banks, circuits, & line segments	X									
		X								
			X							
Pre- and Post-Application projects, banks, circuits				X						
					X					
Pre- and Post-Application Projects						X				
							X			
								X		
									X	
										X

$$\text{RECC} = \frac{(r-i)}{(1+r)}\left(\frac{(1+r)^N}{(1+r)^N-(1+i)^N}\right)$$

The Project Revenue Requirement is calculated by multiplying the estimated capital cost of the equipment with the Revenue Requirement Multiplier (RRQ Multiplier or RRM). The RRQ Multiplier represents costs recovered from utility customers and includes costs such as taxes, franchise fees, utility authorized rate of return, and overheads. In equation form, the Project Revenue Requirement is:

Project Revenue Requirement = Estimated Project Capital Cost * RRQ Multiplier

If a DER is procured instead of building a traditional wires project, utility customers also benefit by avoiding any annual O&M activities associated with the traditional wires project equipment which is not built. Since O&M is an expense item that is passed to customers in the year it is incurred, it is not multiplied by the RECC factor or the RRM. Since O&M costs are incurred in the year that they are performed O&M is also subject to inflation adjustments.

The complete expression of the cost reduction associated with a one-year deferral is thus:

Deferral Benefit = [[Project Capital Cost] x [RECC Factor] x [RRQ Multiplier] + annual O&M]

To calculate the value of a multiple-year deferral, the yearly deferral values for each year after the first year are calculated and simply discounted to a present value using a discount factor derived from same discount and inflation rates used in the RECC factor and then the discounted values are summed together to form the multiple year deferral value.

The key assumptions for the LNBA calculation for capacity projects include the following:

- Discount rate: Derived from the utility's weighted average cost of capital.
- Inflation rate: Inflation rates for equipment and O&M as assumed as per utility's practice.
- Life of a traditional project: Assumptions for project life as per utility's practice.
- Equipment Capital Cost: Cost of the project equipment as per utility's practice.
- O&M costs: Cost of O&M as per utility's practice. Expressed as a percentage of the project's capital cost.

In general, SDG&E's LNBA calculations followed the same calculations as those included in the E3 LNBA tool. However, SDG&E used their own set of assumptions for the key inputs to the deferral calculation. The inputs and outputs of SDG&E's LNBA calculation are discussed below.

Verification of LNBA Results

We verified the inputs that went into the LNBA calculation, as well as the calculation itself, as discussed below.

Key inputs

The key inputs to the LNBA calculation are shown in the table below. Since the planned projects are circuit-related, only the inputs assumed for UG and OH are shown in the table. Some of the inputs such as equipment and O&M inflation factors were the standard inputs used in E3's LNBA calculator. Other inputs such as O&M factor and book life were adjusted by SDG&E to match with SDGE's GRC filing and Rule 2 – Description of Service. SDG&E used a discount rate of 7% which should be based on its weighted average cost of capital. One other key input for the LNBA calculation is the capital cost of equipment for each project which was discussed in Section 7.3.2. Table 7-20 shows the factors used in the SDG&E LNBA calculation for a Primary Underground Circuit and for and Primary Overhead Circuit. These values are the same as last year's.

Table 7-20: Assumptions for LNBA Calculations

Input	Primary UG Circuit	Primary OH Circuit	Source
Revenue Requirement Multiplier	1.50	1.50	Standard assumption in LNBA Calculator
Equipment Inflation	2.0%	2.0%	Standard assumption in LNBA Calculator
O&M Inflation	2.0%	2.0%	Standard assumption in LNBA Calculator
O&M Factor	1.9%	7.4%	O&M Factor was modified to match the Special Facilities and Maintenance within SDG&E's Rule 2 - Description of Service.
Book Life	30	30	Book life changed from 25 to 30 years to match GRC.
RECC	0.061	0.061	Calculated
Discount rate net or project inflation (5/yr.)	4.9%	4.9%	Calculated

Results

The LNBA values shown in SD&E's DDOR report were verified using the formula shown in E3's LNBA calculator for one of the planned projects (DDOR 2022_0001) as shown in Table 7-21. The calculated values (LNBA range) match those provided in the DDOR report for this circuit. In this table, the values from SDG&E's LNBA calculation are shown in column 3. The corresponding values calculated using E3's formula, as well as the formula themselves are shown in the 4th and 5th columns respectively.

Table 7-21: LNBA Calculation verification for DDOR 2021_0003

Row #	LNBA Item	Values shown in DDOR Report (C)	IPE Calculations based on E3 LNBA formula (D)	E3 LNBA formula (E)
3	Project Cost	$ 329.00	Input verified	
4	Revenue Requirement Multiplier	1.50	Input verified	
5	Equipment Inflation	0.02	Input verified	
6	O&M Inflation	0.02	Input verified	
7	O&M Factor	0.07	Input verified	
8	Book Life	30.00	Input verified	
9	RECC	0.06	0.06	(C12-C5)/(1+C12)*((1+C12)^C8/((1+C12)^C8-(1+C5)^C8))
10	Discount rate net or project inflation (5/yr)	0.05	Input verified	
11	Incremental O&M Cost	$ 24.35	$ 24.35	C3*C7
12	Discount Rate (%/yr)	0.07	Input verified	
13	DER Install Year	2024	Input verified	
14	Discount rate net or project inflation (%/yr)	0.05	0.05	(1+C12)/(1+C5)-1
15	Discount rate net of O&M inflation (%/yr)	0.05	Input verified	
16	O&M Inflation Rate (%/yr)	0.02	Input verified	
17	Revenue Requirement Cost in Nominal Dollars in Analysis Yr $'s	$ 493.50	$ 493.50	C4*(C3*(1+C5)^(2020-2020))
18	Revenue Requirement Cost in Nominal Dollars in Analysis Yr $'s * RECC	$ 30.26	$ 30.26	C17*C9
19	Deferred Capital Cost (2022)		$ -	MAX(0,IFERROR(PV($C$10,1-$G$6,-$D$18,0,1)/(1+$C$10)^$G$6,0))
20	Deferred Capital Cost (2023)	$ -	$ -	MAX(0,IFERROR(PV($C$10,2-$G$6,-$D$18,0,1)/(1+$C$10)^$G$6,0))
21	Deferred Capital Cost (2024)	$ 27.50	$ 27.50	MAX(0,IFERROR(PV($C$10,3-$G$6,-$D$18,0,1)/(1+$C$10)^$G$6,0))
22	Deferred Capital Cost (2025)	$ 53.71	$ 53.71	MAX(0,IFERROR(PV($C$10,4-$G$6,-$D$18,0,1)/(1+$C$10)^$G$6,0))
23	Deferred Capital Cost (2026)	$ 78.70	$ 78.70	MAX(0,IFERROR(PV($C$10,5-$G$6,-$D$18,0,1)/(1+$C$10)^$G$6,0))
24	Deferred Capital Cost (2027)	$ 102.53	$ 102.53	MAX(0,IFERROR(PV($C$10,6-$G$6,-$D$18,0,1)/(1+$C$10)^$G$6,0))
25	Deferred Capital Cost (2028)	$ 125.23	$ 125.23	MAX(0,IFERROR(PV($C$10,7-$G$6,-$D$18,0,1)/(1+$C$10)^$G$6,0))
26	Deferred Capital Cost (2029)	$ 146.88	$ 146.88	MAX(0,IFERROR(PV($C$10,8-$G$6,-$D$18,0,1)/(1+$C$10)^$G$6,0))
27	Deferred Capital Cost (2030)	$ 167.52	$ 167.52	MAX(0,IFERROR(PV($C$10,9-$G$6,-$D$18,0,1)/(1+$C$10)^$G$6,0))
28	Deferred Capital Cost (2031)	$ 187.19	$ 187.19	MAX(0,IFERROR(PV($C$10,10-$G$6,-$D$18,0,1)/(1+$C$10)^$G$6,0))
29	Deferred O&M Cost (2022)	$ -	$ -	MAX(0,PV($C$15,1-$G$6,-$C$11,0,1)*(1+0.02)^($C$13-$G$3)/(1+$C$15)^$G$6)
30	Deferred O&M Cost (2023)	$ -	$ -	MAX(0,PV($C$15,2-$G$6,-$C$11,0,1)*(1+0.02)^($C$13-$G$3)/(1+$C$15)^$G$6)
31	Deferred O&M Cost (2024)	$ 23.02	$ 23.02	MAX(0,PV($C$15,3-$G$6,-$C$11,0,1)*(1+0.02)^($C$13-$G$3)/(1+$C$15)^$G$6)
32	Deferred O&M Cost (2025)	$ 44.96	$ 44.96	MAX(0,PV($C$15,4-$G$6,-$C$11,0,1)*(1+0.02)^($C$13-$G$3)/(1+$C$15)^$G$6)
33	Deferred O&M Cost (2026)	$ 65.88	$ 65.88	MAX(0,PV($C$15,5-$G$6,-$C$11,0,1)*(1+0.02)^($C$13-$G$3)/(1+$C$15)^$G$6)
34	Deferred O&M Cost (2027)	$ 85.82	$ 85.82	MAX(0,PV($C$15,6-$G$6,-$C$11,0,1)*(1+0.02)^($C$13-$G$3)/(1+$C$15)^$G$6)
35	Deferred O&M Cost (2028)	$ 104.82	$ 104.83	MAX(0,PV($C$15,7-$G$6,-$C$11,0,1)*(1+0.02)^($C$13-$G$3)/(1+$C$15)^$G$6)
36	Deferred O&M Cost (2029)	$ 122.94	$ 122.95	MAX(0,PV($C$15,8-$G$6,-$C$11,0,1)*(1+0.02)^($C$13-$G$3)/(1+$C$15)^$G$6)
37	Deferred O&M Cost (2030)	$ 140.22	$ 140.23	MAX(0,PV($C$15,9-$G$6,-$C$11,0,1)*(1+0.02)^($C$13-$G$3)/(1+$C$15)^$G$6)
38	Deferred O&M Cost (2031)	$ 156.68	$ 156.70	MAX(0,PV($C$15,10-$G$6,-$C$11,0,1)*(1+0.02)^($C$13-$G$3)/(1+$C$15)^$G$6)
39	Total Deferred Costs (2022)	$ -	$ -	SUM(D19,D29)
40	Total Deferred Costs (2023)	$ -	$ -	SUM(D20,D30)
41	Total Deferred Costs (2024)	$ 50.52	$ 50.52	SUM(D21,D31)
42	Total Deferred Costs (2025)	$ 98.67	$ 98.68	SUM(D22,D32)
43	Total Deferred Costs (2026)	$ 144.58	$ 144.58	SUM(D23,D33)
44	Total Deferred Costs (2027)	$ 188.34	$ 188.35	SUM(D24,D34)
45	Total Deferred Costs (2028)	$ 230.06	$ 230.06	SUM(D25,D35)
46	Total Deferred Costs (2029)	$ 269.82	$ 269.83	SUM(D26,D36)
47	Total Deferred Costs (2030)	$ 307.73	$ 307.74	SUM(D27,D37)
48	Total Deferred Costs (2031)	$ 343.87	$ 343.88	SUM(D28,D38)
49	Cumulative Reduction Needed for Deferral (2021)			
50	Cumulative Reduction Needed for Deferral (2022)			
51	Cumulative Reduction Needed for Deferral (2023)	0.24		
52	Cumulative Reduction Needed for Deferral (2024)	0.27		
53	Cumulative Reduction Needed for Deferral (2025)	0.37	Input verified	
54	Cumulative Reduction Needed for Deferral (2026)		Input verified	
55	Cumulative Reduction Needed for Deferral (2027)		Input verified	
56	Cumulative Reduction Needed for Deferral (2028)		Input verified	
57	Cumulative Reduction Needed for Deferral (2029)		Input verified	
58	Cumulative Reduction Needed for Deferral (2030)		Input verified	
59	First 10 Year Deferral Value ($000s)	$ 343.87	$ 343.88	D48
60	Max Need during First 5 Yrs (MW)	0.37	0.37	MAX(C49:C58)
61	10 Year LNBA value	$ 117.41	$ 116.17	C59/C60/(10-$G$6)
62	Reported LNBA Range	$100-$500	Verified	

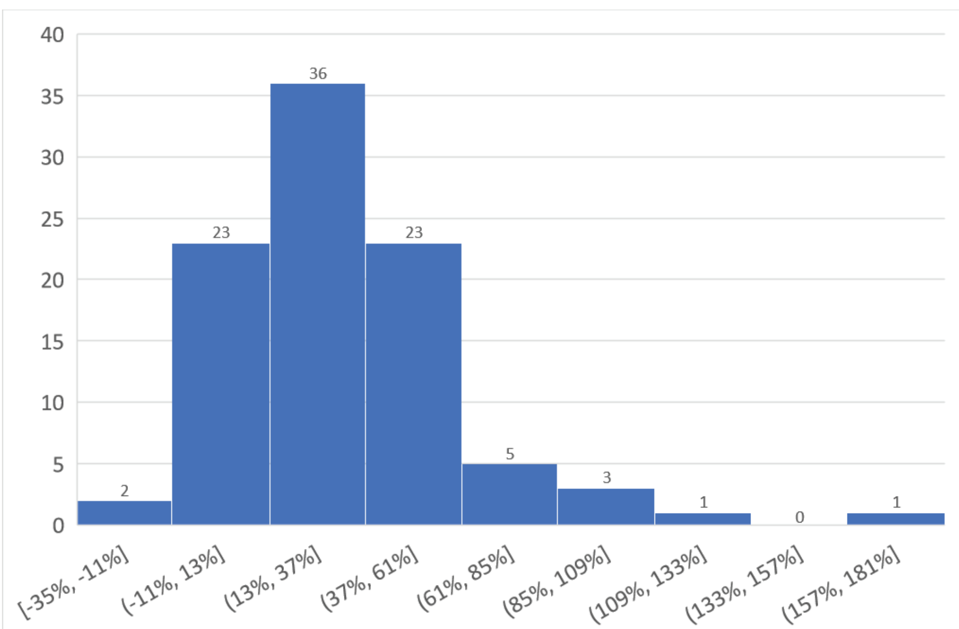
7.4.5. Compare 2021 Forecast and Actuals at Circuit Level – Step 19

The purpose of this step is to perform a comparison of the forecast versus actual peak load for a number of circuits that we believe comprises a “statistically significant” sample size. We believe that performing a comparison for 10% of all circuits will provide a statistically significant result. The purpose is to get some insight into the “accuracy” of the overall circuit planning process recognizing that there are many variables that can affect the comparison; many of these variables are beyond the control of the utility.

The IPE plan for this step calls for a comparison of the forecasted peak load for year 2021 for selected circuits (obtained from the 2020 GNA) with the 2021 actual peak load. Figure 7-14 shows the comparison where the difference between the forecast and actual expressed as percentage (of actual) is shown as a histogram. It can be seen that for 36 of the 94 circuits (approximately 40%), the difference is between 13% and 37%. This is because we were comparing forecasted loads that are based on 1-in-10 weather conditions with actual loads which were likely not under 1-in-10 weather conditions. The results of this type of comparison are high dependent upon the weather conditions during the year.

The IPE plans to obtain actual 2021 loads adjusted to 1-in-10 from SDG&E and then repeat this analysis with these loads and report out the results in the Post-DPAG report. Please refer to Section 6.2 for a recommendation related to these results.

Figure 7-14: Histogram of Difference between Forecasted and Actual Loads



7.5. OTHER FUTURE IPE WORK

7.5.1. Respond to and Incorporate DPAG Comments – Step 22

The IPE was available during the SDG&E DPAG meeting and the SDG&E Follow-Up DPAG meeting to respond to questions raised by stakeholders. There were no written comments or questions directly addressed to the IPE.

7.5.2. Track Solicitation Results to Inform Next Cycle – Step 22

This review was completed in Q3 of 2022. A solicitation tracking tool (an EXCEL workbook) was developed at the Direction of the Energy Division. The IPE participated in the definition of the data to be tracked. Going forward the Independent Engineer for each utility will update the information in the tracking tool on a regular basis.

7.5.3. Treating confidential material in the IPE report – Step 24

The IPE work products have followed the process and steps included in this Business Step in developing the IPE Final Report. Additional actions were taken to minimize the material that is redacted in the public version of this report to maximize the readers ability to understand what the IPE did during this DIDF cycle.

Appendix A IPE Scope

R.14-08-013, A.15-07-005, *et al.* ALJ/RIM/nd3

Attachment A
Listing of Schedule and IPE-Specific Reforms for the 2020-2021 DIDF Cycle

1. IPE-specific reforms for the 2020-2021 DIDF Cycle are implemented within the IPE Scope of Work presented in Attachment B.

2. IOU contracts with the IPE for the full scope of work identified in Attachment B shall be executed by the IOUs to allow for IPE Plan development to begin as soon as possible, ideally on or before **April 17, 2020**.

3. The IOUs shall work with the IPE and Energy Division to develop IPE Plans specific to each IOU such that the IPE can submit the Draft IPE Plans to Energy Division for review on or before **May 15, 2020**.

4. The IPE scope of work may be modified by Energy Division as needed for the IPE to successfully complete each assignment. The IOUs will promptly submit a Tier 1 Advice Letter to notice changes in scope should a scope change differ significantly from the scope described in Attachment B. Minor changes should not necessitate an Advice Letter filing.

5. As required by Energy Division on an annual basis, Pre-DPAG and Post-DPAG activities may include workshops; new, re-opened, suspended, or modified working groups (e.g., Distribution Forecast Working Group); and IOU presentations and deliverables.

6. During the Post-DPAG period and in consultation with the IPE, Energy Division may identify exemplary GNA/DDOR documentation components, analytical approaches, or data strategies implemented by one or more IOUs and require that each IOU implement the reform in future DIDF cycles.

(end of Attachment A)

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Attachment B
IPE Scope of Work for DIDF Implementation

Term

- January 1st each year to July 31st the following year with the term subject to update by Energy Division if needed to support each DIDF cycle.

Pre-DPAG Period

- Develop an ***IPE Plan*** for each IOU describing the GNA/DDOR review process and detailed approach to Verification and Validation of all data used by the IOUs to prepare their DIDF filing materials.
    - Verification and Validation will include a thorough investigation of the following IOU processes, among others:
        - Collecting circuit loadings and performing weather adjustments;
        - Determining load and DER annual growth on the system level;
        - Disaggregating load and DER annual growth to the circuit level;
        - Checking sum of all disaggregated load and DERs against system-level values;
        - Adding incremental known loads to circuit level forecasts;
        - Developing load, DER, and net load profiles and determining net peak loads;
        - Adjusting for extreme weather;
        - Comparisons to equipment ratings to determine if ratings will be exceeded;
        - Incorporating load transfers, phase transfers, correcting data errors;
        - Compiling GNA tables showing need amount and timing; and
        - Following the IOU's planning standard and/or planning process.
    - GNA/DDOR report review will include an in-depth analysis of the following IOU steps, among others:
        - Developing recommended solutions (planned investments);
        - Implementing the IOU's planning standards and/or planning process;
        - Estimating capital costs for planned investments;

- Developing list of candidate deferral projects through application of screens (timing and technical);
- Developing operational requirements;
- Prioritization of candidate deferral projects into tiers;
- Calculating LNBA values; and
- Comparing prior-year forecast and actuals at circuit level for candidate deferral projects.

- Work directly with the IOUs and Energy Division to develop draft plans as needed. Development of the draft IPE Plans may include, among other activities:
  - Meeting with the IOUs and Energy Division to identify and understand each business process and tool used to complete their GNA/DDOR filings.
- Facilitate or participate in stakeholder workshops to receive feedback on the IPE Plans.
- Review and incorporate comments in the final IPE Plans.
- Submit final IPE Plans to Energy Division and the IOUs with recommendations for future improvements to the plans.
- Other technical support assignments as defined by Energy Division to ensure the IPE and Energy Division will receive from the IOUs the data and cooperation necessary to complete the required evaluation of the GNA/DDOR filings.

DPAG Period

- Participate in all workshops and meetings during the DPAG period. Prepare and deliver presentations or handouts as requested by Energy Division (*e.g.*, final IPE Plan presentations).
- Develop an ***IPE Preliminary Analysis of GNA/DDOR Data Adequacy*** for all three IOUs.
- Review any comments on the preliminary analysis that may be received and discuss the results with Energy Division.

- Facilitate meetings with Energy Division and the IOUs to correct data inadequacies and prepare further documentation and provide technical support as needed.
- Fully implement each IPE Plan as defined in the final IPE Plans.
- Develop an ***IPE DPAG Report*** for each IOU presenting GNA/DDOR review findings and Verification & Validation outcomes.
- Submit the draft reports to Energy Division for review and (if necessary) to the IOUs to check for confidential information that may be included or to clarify specific details.
- Circulate the final IPE DPAG Reports to stakeholders (public and confidential versions).
- Other technical support assignments as defined by Energy Division to ensure the DPAG process is successfully completed.

Sample Size

- The scope of review conducted by the IPE for each IOU process may encompass the full set of circuits/projects or a subset/sample of circuits or projects. Where sampling is determined to be appropriate by the IPE in consultation with Energy Division, the size of the sample set for each case will be determined by the IPE based on the application of engineering judgement.

Post-DPAG Period

- Develop a single ***IPE Post-DPAG Report*** covering all three IOUs; comparing their current and prior filings; evaluating DIDF DER procurement, operational, cost, and contingency planning outcomes; reviewing IOU compliance; and making recommendations for process improvements and DIDF reform.
- Coordinate with and support the Independent Evaluator (IE) with IE activities and the development of IE reports as needed.
- Submit the draft report to Energy Division for review and (if necessary) to the IOUs to check for confidential information that may be included.

Appendix B DPAG Survey and Comment Responses

SDG&E solicited feedback from the DPAG during their DPAG meeting on September 21, 2022 and also solicited comments by email. There were a number of comments from the Energy Division Department and the Public Advocates Office directed to SDG&E. The responses to these questions were posted by SDG&E to the R.21-06-017 Service List on October 6, 2022 and discussed during their DPAG follow-on meeting on October 20, 2022.

Appendix C Copy of the IPE Plan

Note: The IPE Plan for SDG&E is included in a separate file from the file containing this report.

Independent Professional Engineer Plan San Diego Gas & Electric - Final

Submitted to California Public Utility Commission

9/21/2022

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Contents

1 Introduction and Background

This document is the draft version of the Independent Professional Engineer Plan for the 2022/2023 Distribution Infrastructure Deferral Framework (DIDF) cycle for San Diego Gas and Electric (SDG&E). The requirements for the plan and oversight by the Energy Division are spelled out in a CPUC Ruling 14-08-013 (April 13, 2020) which is attached as Appendix A. The Ruling modified the Distribution Investment Deferral Framework (DIDF) process and previous rulings with respect to the Independent Professional Engineer (IPE) scope of work and provided the updated 2020-2021 DIDF cycle schedule. As of writing this draft report, the 2022/2023 cycle schedule has not been finalized.

As a result of stakeholder comments regarding improving the effectiveness of the IPE process, schedule and expected results, a number of modifications were made by the Ruling and implemented for the first time in the 2020/2021 DIDF cycle. These changes have been incorporated in the IPE Plans developed ever since the previous cycle. Some of these changes are highlighted below:

- The IPE review process now starts earlier to allow for more time for the IPE, utilities and the Energy Division to perform the necessary production of data in response to data requests, verify and validate the data, produce reports and address the confidentiality of data in the reports prior to the IPE Report deadline. The review process starts in the late-April timeframe.
- The IPE scope includes development of a draft IPE Plan for each utility by mid-May in each cycle. The plan will go through a stakeholder review cycle and will be issued in final form by the IPE in August.
- The scope of the IPE review was expanded to include several new business processes
- The scope of the review was expanded to include the new CPUC Standard Offer Contract (SOC) and Partnership Pilots (PP).
- The original schedule for IPE deliverables was established by CPUC Rulings for the 2020/2021 cycle[1]:
    - Draft IPE Plan. Due May 13, 2020 (Reflects 2021/2022 cycle dates)
    - Final IPE Plan. Due August 27, 2020. (Reflects 2021/2022 cycle dates)
    - IPE Preliminary Analysis of GNA/DDOR Data Adequacy for all three IOUs. Due 9/5/20. (Reflects 2021/2022 cycle dates)

[1] Dates shown below are as set forth in the 2020 Ruling. The CPUC plans to issue a ruling with dates for the 2022/2023 DIDF cycle in May. These updated dates will be included in the Final SDG&E IPE Plan.

- IPE DPAG Report for each IOU presenting GNA/DDOR review findings and Verification & Validation outcomes. Due 11/15/20. Reflects 2021/2022 cycle dates)
- IPE Post DPAG Report covering all three IOUs, comparing their filings, reviewing compliance, and making recommendations for process improvements and DIDF reform. Due March 17 2022. (Reflects 2021/2022 cycle dates)

The May 2022 draft IPE Plan will be distributed to stakeholders in May to facilitate stakeholder comments prior to finalizing the IPE Plan in September 2022.

2 Description of the Plan

2.1 Definitions Used in the Plan and Other Deliverables

To facilitate understanding of the IPE scope of work, the following definitions are included and will be used in the Plan and throughout all of the IPE work products and deliverables.

> Verification – Is a review performed by the IPE during which an independent check is performed to determine if the results produced were developed using data assumptions and business processes that were defined and described by the utility or are based upon standard industry approaches that do not have to be defined and described. In other words, "Did the IOU follow their own processes correctly as defined and described by the IOU?"

> Validation – Is a review performed by the IPE during which an independent assessment is performed of the appropriateness of the approach taken by the utility to perform a task from an engineering, economics and business perspective. In other words, "Are the processes implemented by the IOU the best way to identify all planned investments that could feasibly be deferred by DERs cost effectively? And to what extent were the IOU methodologies appropriate and effective?"

The IPE Plan covers the business processes that the IOUs use to identify which distribution or sub-transmission projects are recommended to proceed to 1) an RFO, 2) Standard Offer Contract or 3) Partnership Pilot seeking DER bids to determine if there is a cost-effective non-wires alternative. One of the core purposes of the plan is to answer the question - Are the IOUs identifying every project that could feasibly and cost effectively be deferred by DERs?

The business processes in the Plan are organized generally in the order that they are performed. Starting with capturing the peak load values for each circuit for 2020, using the CEC IEPR forecasts to develop utility specific system level values which are then disaggregated to the circuit level adjusted for known loads then used to determine if there is an overload or other issue during the planning period (nominally 2022 through 2026). For circuits that have a need, a planned investment is selected, capital costs developed for that project and the planned investments are screened to develop a list of candidate deferral projects. These candidate deferral projects are then prioritized into tiers using several metrics with the projects in the first tier normally recommended for a DER RFO. Candidate deferral projects are also considered for SOC or PP pilot programs based upon the results of the prioritization process along with additional set of metrics for SOC and PP pilots.

As indicated earlier, in the 2021/2022 cycle two new pilot programs were initiated that are testing new mechanisms to procure DERs. They are called the Partnership Pilot and a Standard Offer Contract. These pilots impact other parts of the business processes covered in the IPE Plan.

3 IPE Plan

The heart of the IPE Plan is the material contained in Table 3-1 below. This table lists the business processes, roles of the utility and IPE, target timing and information requirements for each business process in the IPE scope. Listed below is a more detailed description of the contents of Table 3-1:

- IOU Business Process / IPE Review Step – This column includes a number for each business process included in the table. To make it easier for readers who will be looking at more than one utility IPE Plan, the process was started with the same numbering for all three utilities and that set of numbers was maintained as much as possible. In cases where additional steps needed to be added to accommodate a utilities specific unique process a letter was added to the previous number. For example, the step after Step 3 was added and was number Step 3a. For cases where steps are not needed, they will be spelled out in the table.
- Business Process / IPE Review Step Description – This column contains a general description of the business process being reviewed.
- Plan for 2022/23 DIDF Cycle – This column includes several types of information:
  - A brief description of what the review will include and whether it would include review of a subset of the total number of elements (i.e., circuits) or all elements and what is being examined.
  - Roles which include the role of the utility overall and the role of the IPE for both the verification and validation review. For both reviews, an indication is provided for what the IPE will be checking for or confirming in the review.
    Note that there are generally two approaches to performing a verification. The first is a demonstration wherein the utility develops the necessary spreadsheet or other mechanism to show how the business process developed the results of interest and the IPE performs a walk through to view the demonstration by the utility. The second approach is wherein the IPE develops a spreadsheet or other mechanism to calculate the results of interest using data provided by the utility and then compares the results to the numerical utilities results.
- Target Timing – This column includes a target timing for the reviews in the business process in this row or in the timing that data will be provided to the IPE.
- Data/Information Requirements – This column includes the data or information that the IPE needs to perform its review and in some cases the date the information is required.

Table 3-1 SDG&E IPE Review for 2022/23 DIDF Cycle is shown starting on the following page.

Table 3-1: SDG&E IPE Review for 2021/22 DIDF Cycle

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
	PROCESSES TO DEVELOP STARTING POINT LOAD, SYSTEM LEVEL VALUES AND DISAGGREGATE TO CIRCUIT LEVEL			
1	Collect 2021 actual circuit loading and adjust for weather as needed	Perform verification for 8-10 circuits jointly selected by the IPE and SDG&E; check results including normalization to typical weather day. Examine weather adjustment factors/relationships for SDG&E regions. Perform validation of the process. Roles: SDG&E to provide the 2021 peak load for selected circuits within their territory. SDG&E also to provide data for weather adjustment factors such as temperatures HDD, CDD, historical feeder/substation loads and other data, as applicable, that are used for the calculation of weather-adjusted peak loads, as well as a description of the general procedure used for calculating weather-adjusted peak loads. Verification:	Selection of feeders by the June 15. The information requested in the “Data/ Information Requirements” by June 15.	▪ Description of business process used to develop weather-normalized peak loads for each circuit, if it’s different from 2021 DIDF. ▪ 2021 peak load and the day and hour the peak load occurred for selected circuits. ▪ 8760 hourly loads before and after removal of data errors, data drops and load transfers from SCADAScrubber for selected circuits.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		IPE to verify that the weather-adjusted peak loads calculated using the data and information provided by SDG&E matches reasonably well with the values produced by SDG&E for the circuits examined. Validation: IPE to review the business process for reasonableness and consistent with the objectives of the DIDF process.		▪ Data for weather adjustment factors such as temperatures, HDD, CDD, historical feeder loads and other factors. ▪ General procedure used for calculating weather-adjusted peak loads, if it's different from 2021 DIDF.
2	Determine load and DER annual growth on system level	Perform V&V on all aspects of this process Roles: SDG&E to provide the spreadsheet used for calculating the year-to-year, cumulative change in system-level load by class, as well as the year-to-year change in DER capacity used in the next steps. Verification: IPE to verify the calculations performed by SDG&E. IPE to compare output results of this process are the same as those used in the next step of the process (Step 3).	Description and links to IEPR forecasts provided by June 15. Spreadsheet used for calculating system-level load and DER capacity growth by June 15.	▪ Provide the spreadsheet that uses the CEC IEPR forecast as the starting point and calculates year-to-year change in load (and the hourly files used to forecast DER capacity) used in the next steps. ▪ Identify which IEPR forecasts are being used for load and all DERs.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		Verify that the system level load and DER capacity calculated by the IPE matches reasonably well with those provided by SDG&E. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		▪ Provide description of the process if different than used in 2021 DIDF.
3	Disaggregate load and DER annual growth to the circuit level	Perform verification for all circuits and validation of the process. Roles: SDG&E to provide the inputs and outputs, as well as a general description of the processes used for disaggregating system-level load (changes) to circuit-level and further at a class level (Domestic, Commercial, Industrial) using LoadSEER. SDG&E to provide the inputs and outputs, as well as a general description of the processes used for disaggregating system-level DER capacity to circuit-level capacity. SDG&E to demo the software tools used in this step, as well as the inputs and outputs.	SDG&E to provide material requested in "Data/ Information Requested" by June 15.	▪ Inputs and outputs, as well as a general description of the process used for disaggregating system-level load to circuit-level loads and further at a class level (Domestic, Commercial, Industrial) using LoadSEER, if different from the process used in the 2021 DIDF.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		Verification: IPE to verify that load and DER capacity forecast for selected circuits match with those used in subsequent steps of the load forecasting process (starting in Step 4). Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		▪ Inputs and outputs, as well as a general description of the process used for disaggregating system-level DER capacity to circuit-level capacity, if different from the process used in the 2021 DIDF.
3a	Check sum of all disaggregated load and DERs same as CEC IPER System Level values	Perform V&V on this aggregation for all circuit values as well as cross check values used in other verification checks. Roles: SDG&E provides the needed information in the previous step. Verification: Verify that the sum of the loads (by class) and DER capacities at the circuit level matches reasonably well with the system level value from Step 2.		Use data from previous step.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
4	Add Incremental known loads to circuit level forecasts (in CEC forecasts and others not in CEC forecast)	Perform V&V for a subset of circuits selected by the IPE Roles: SDG&E to demonstrate how it adds incremental known loads for cases where 1) the load is assumed to be embedded in the CEC system level values and 2) if applicable, the load that is in addition to the CEC system level forecasts. SDG&E to demonstrate how loads are added and any adjustments to system level values are accomplished. Verification: IPE to verify that business process demonstration by SDG&E is the same as described in SDG&E documentation.	SDG&E to provide the requested information by June 15.	▪ SDG&E to provide a summary of statistics for system-level incremental loads by year identifying how many, size of new load and type, if available. ▪ SDG&E to provide circuit-level known load additions by customer class that adds up to the system level values.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		IPE to verify that the sum of the circuit-level known load additions by customer class matches with the system-level values in Step 2. IPE to verify that the circuit-level known load additions for selected circuits match with those used in LoadSEER (Starting with Step 5). Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
5	Convert peak growth of load to 576 profile as needed	Perform V&V for a subset of circuits selected by the IPE Roles: SDG&E to provide 576- hourly profile for loads (Company Forecast, Adjustment for Load Growth) from LoadSEER for the subset of circuits. SDG&E to also provide typical load shapes for load classes (COM, IND, and DOM). Verification:	SDG&E and IPE to select the circuits for this analysis by July 10. SDG&E to provide the requested LoadSEER data by July 10.	▪ SDG&E to provide 576-hourly profile for loads (Company Forecast, Adjustment for Load Growth) for the subset of circuits. ▪ SDG&E to also provide typical load shapes for load classes (COM, IND, and DOM).

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		IPE to use company load forecast from Step 8 and the class load profiles to develop the 576-hourly profile for loads (Company Forecast, Adjustment for Load Growth) and verify it against the data provided by SDG&E. Verify that the 576-hourly forecast load profiles calculated match reasonably well with those provided by SDG&E for a subset of circuits. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
5a	Convert DER growth to 576 profile as needed	Perform V&V for a subset of circuits selected by the IPE Roles: SDG&E to provide 576- hourly profile for DERs (Load adjustments for EV, EE, ES, PV) from LoadSEER for the subset of circuits. SDG&E to also provide typical load shapes for all the DERs, by classes as applicable.	SDG&E to provide the requested LoadSEER data by July 10.	▪ SDG&E to provide 576-hourly profile for DERs (Load adjustments for EV, EE, ES, PV) from LoadSEER for the subset of circuits. ▪ SDG&E to also provide typical load shapes for all the DERs, by classes as applicable.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		Verification: IPE to use DER forecast from Step 3 and the typical DER profiles to develop the 576-hourly profiles for DER adjustments and verify it against the data provided by SDG&E. Verify that the 576-hourly load adjustment profiles calculated for EV, EE, ES and PV match reasonably well with those provided by SDG&E for a subset of circuits. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		▪ SDG&E to also provide information on how these typical DER load profiles were developed.
				▪
5b	Convert base forecast and Weather normalization adjustment of load to 576 profile as needed	Perform V&V for a subset of circuits selected by the IPE Roles: SDG&E to provide 576- hourly profile for base (load) forecast and weather normalization adjustment from LoadSEER for the subset of circuits. SDG&E to also provide typical load shapes	SDG&E to provide the requested LoadSEER data by July 10.	▪ SDG&E to provide 576-hourly profile for base forecast and weather normalization adjustment from LoadSEER for the subset of circuits.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		associated with base forecast and weather normalization adjustment. Verification: IPE to use load forecast from Step 8 and the typical profiles provided by SDG&E to develop the 576-hourly profile for loads (for base forecast and weather normalization adjustment) and verify it against the data provided by SDG&E. Verify that the 576-hourly base and weather normalization load profiles calculated match reasonably well with those provided by SDG&E for a subset of circuits. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		▪ SDG&E to also provide typical load shapes associated with base forecast and weather normalization adjustment.
6	Derive net load profile	Perform V&V for a subset of circuits selected by the IPE Roles:	No additional data required.	▪

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		SDG&E to provide 576- hourly net load profile for the subset of circuits before incorporating load transfers, phase transfers, and corrections for data errors. Verification: IPE to use the results of Steps 5, 5a and 5b to calculate net load profile and compare with the profile provided by SDG&E. Verify that the 576-hourly net load profiles calculated match reasonably well with those provided by SDG&E for a subset of circuits. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
7	Determine net peak load	Perform V&V for a subset of circuits selected by the IPE Roles:	SDG&E to provide the requested LoadSEER data by July 10.	▪ SDG&E to provide the adjusted peak load forecast (Before Project Forecast) for the subset of circuits for the peak load hour

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		SDG&E to provide the peak load forecast (Before Project Forecast) for the subset of circuits for the peak load hour. Verification: IPE to verify the value provided by SDG&E against the value obtained for the peak day from the 576 hourly net load profile developed in Step 6. IPE to also verify that the peak load values used in Step 9 match with the values obtained in this step for a subset of circuits. Verify that the peak value of the 576-hourly net load profile matches reasonably well with the value provided by SDG&E for selected circuits. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
8	Adjust for "extreme weather"	Perform V&V for a subset of circuits selected by the IPE Roles:	Performed along with Step 1	▪ Description of business process used to develop P95 peak loads for each circuit, if

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
	Please note that process is completed after Step 4.	SDG&E to provide the P95 load forecasts (base forecast, corporate forecast and Adjustment for weather normalization) for selected number of circuits. SDG&E also to provide data for weather adjustment factors such as temperatures, historical feeder/substation loads and other data that are used for the calculation of weather-adjusted peak loads in LoadSEER, as well as a description of the general procedure used by LoadSEER for calculating weather-adjusted peak loads. Verification: IPE to use the data and the procedure provided by SDG&E to independently verify the P95 load forecasts developed by LoadSEER. If the IPE is not able to verify the peak load forecasts due to the complexity of calculations or lack of data and/or documentation, SDG&E will demonstrate the tool used, its inputs and outputs. Validation:		different from the process used in the 2021 DIDF. ▪ General procedure used by LoadSEER for calculating weather-adjusted peak loads, if different from the process used in the 2021 DIDF. ▪ P95 load forecasts (base forecast, corporate forecast and Adjustment for weather normalization) for selected number of circuits. SDG&E also to provide data for weather adjustment factors such as temperatures, historical feeder/substation loads and other data that are

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		used for the calculation of weather-adjusted peak loads in LoadSEER
	PROCESSES TO DETERMINE CIRCUIT NEEDS AND DEVELOP GNA			
9	Initial comparison to equip. ratings to determine if ratings exceeded	Perform V&V for a subset of circuits selected by the IPE Roles: SDG&E to provide equipment ratings for a subset of circuits selected by the IPE. Verification: IPE to compare the net peak load from Step 7 before any load transfers, phase transfers and compare it with the rating to determine if there is an overload (and the overload matches with the value calculated by SDG&E). Verify that the overloads calculated by the IPE match reasonably well with those provided by SDG&E for a subset of circuits.	SDG&E to provide requested information by July 10.	▪ SDG&E to provide equipment ratings for a subset of circuits selected by the IPE.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
10	Incorporate load transfers, phase transfers, correct data errors	Perform V&V for a subset of circuits selected by the IPE Roles: SDG&E to demonstrate how it makes adjustments to load forecasting based upon phase transfers, data error corrections and load transfers. Demonstration will include what data is relied upon to predict the impact of making the proposed changes (i.e., phase transfer). Verification: IPE to verify the process reflected in the SDG&E demonstration is consistent with the SDG&E process description and the result are the same as used in subsequent steps in process of developing the GNA. IPE to also verify the before and after load profiles for both the circuits where the load is transferred from, and the load is transferred to.	SDG&E to provide requested information by August 10.	SDG&E to provide the LoadSEER before and after load profiles for both the circuits where the load is transferred from and the load is transferred to, as well as the amount of load (MW) that was transferred.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
11	Final comparison to equip. ratings to determine if ratings exceeded	Perform V&V for a subset of circuits selected by the IPE Roles: SDG&E provided the needed information in the prior steps. Verification: IPE to compare the net peak load from Step 8 after any load transfers, phase transfers and compare it with the rating to determine if there is an overload (and the overload matches with the value calculated by SDG&E). Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		Data provided in Step 9.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
12	Compile GNA tables showing need amount and need timing, etc. (per IOU's documented planning standards and/or planning process)	Perform V&V on development of GNA table entries for select circuits also confirming that planning standard/process was followed as appropriate. Roles: SDG&E to provide confidential version of Planned Investment tables in Excel format that can be filtered by the IPE. SDG&E to provide list of planning standards/criteria that were used in the development of the GNA tables. Verification: IPE to review projects in the GNA report are consistent with the information verified in the previous steps and planning standards/criteria. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.	SDG&E to provide requested information by August 31.	▪ Confidential GNA tables in Excel format ▪ Copy of planning standard if different than one used in 2021. ▪ Description of process used, using excerpts from planning assumptions, GNA, and DDOR similar to approach in 2021 cycle. ▪ This step focuses upon an analysis concerning whether planning standards that lead to the identification of needs were followed. It does not include review of the planning standards, themselves.
	PROCESSES TO DEVELOP PLANNED INVESTMENTS AND COSTS			

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
13	Develop recommended solution and generate list of Planned Investments (follow the IOU's documented planning standards and/or planning process)	Perform V&V for a subset of projects selected by the IPE confirming that planning standard/process was followed. Roles: SDG&E to demonstrate/describe process used to determine recommended planned solution for a subset of projects. SDG&E to demonstrate the application of the process in developing the planned investment for selected projects. Verification: IPE to verify the SDG&E demonstration reflects the description of the process provided by SDG&E. IPE to verify that results shown in the demonstration follow the described process are same as included in DDOR. Validation:	SDG&E to provide requested information by August 31.	▪ Description of process used to develop proposed planned project to address identified need for distribution projects.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
14	Estimate capital cost for each Planned Investment	Perform V&V for a subset of projects selected by the IPE Roles: SDG&E to provide the cost breakdown for the planned projects. The breakdown should include direct material, labor and other costs by equipment, as well as indirect material, labor and other costs at a project level. SDG&E to describe the Expected Accuracy Level (as defined by AACE or by another method that describes the expected accuracy range in terms of % lower and higher than the estimate) of the capital costs for the projects included in the DDOR. If the Expected Accuracy is different for different projects, SDG&E to provide the accuracy range for each project.[1]	SDG&E to provide requested information by September 26.	▪ SDG&E to provide the cost breakdown for the planned projects. The cost breakdown should include direct material, labor and other costs by equipment, as well as indirect material, labor and other costs at a project level. ▪ SDG&E supporting information for costs. ▪ SDG&E to provided expected accuracy level of the cost estimates. ▪ All data above provided by mid-August

[1] During the course of implementing the IPE Plan, the ED in coordination with the IPE will seek to understand the effort and cost associated with improving the accuracy of capital cost estimates (i.e., from a Class 4 estimate accuracy to a Class 3 estimate accuracy).

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		SDG&E to provide supporting cost information for a subset of projects. Verification: IPE to verify the project costs provided by SDG&E against other sources such as rate case filings. IPE to verify the total project level costs provided by SDG&E with those included in the DDOR. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
	PROCESSES TO DEVELOP CANDIDATE DEFFERAL LIST AND PRIORITIZE			
15	Development of Candidate Deferral Projects list through application of	Perform V&V for all projects put through the screening process Roles:	SDG&E to provide requested information by September 15.	▪ SDG&E to provide Candidate Deferral calculation process ▪ Confidential version of Planned Investment table in Excel format

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
	screens (timing and technical)	SDG&E to provide confidential version of Planned Investment table in Excel format that can be filtered by the IPE. SDG&E to describe the process it used to develop its Candidate Deferral Projects. Verification: IPE to use the Excel tables to develop a list of Candidate Deferral Projects following the process described by SDG&E. IPE to verify its result (list of Candidate Deferral Projects) match the SDG&E results included in the DDOR. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		that can be filtered by the IPE. ▪ Utilize DPAG materials ▪ Data provided by mid-August
16	Development of operational requirements (daily, monthly annually etc.)	Perform V&V for a subset of candidate deferral projects selected by the IPE Roles: SDG&E to provide description of the process used to determine operational requirements. (Required	SDG&E to provide requested information by September 15.	▪ SDG&E to provide description of how operational requirements are established if different

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		load, months and hours needed, duration of call and number of calls per year). Verification: IPE to utilize description to confirm operational requirements for selected circuits are developed using the process described and that the values developed are the same as included in subsequent steps of the process (DDOR and DPAG) Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		from the process used in 2021.
17	Prioritization of candidate deferral projects into Tiers	Perform V&V on prioritization process for all candidate deferral projects Roles: SDG&E to provide a version of the Excel spreadsheet containing the formula used, if applicable, that is used to determine the metrics and components used to rank the Candidate Deferral Projects overall and into tiers.	SDG&E to provide requested information by September 15.	▪ Demonstrate active spreadsheet that calculates prioritization metrics, components and ranks projects on those results. To include spreadsheets for prioritization of CDOs and for

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		SDG&E to provide active version of spreadsheet (if one is used) used to rank and select candidate deferral projects for procurement using the SOC or PP procurement programs. Verification: IPE to verify that spreadsheet is consistent with the description of the description of the prioritization metrics, components and tier ranking process and SOC and PP ranking/selection process. IPE to verify that Excel results match the recommended Candidate Deferral Projects overall rankings and placement into tiers and recommended for RFO, SCO or PP procurement included in the DDOR and presented at the DPAG meetings. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		ranking/selecting SOC and PP projects ▪ Description of the IOU standardized prioritization metrics, components and tier ranking methodology and process and SOC and PP ranking selection process.
18	Calculate LNBA ranges and	Perform V&V for a subset of projects selected by the IPE	SDG&E to provide	▪ SDG&E to provide the spreadsheet(s) used for

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
	values for all planned investments	Roles: SDG&E to provide a spreadsheet (containing the formula) used for calculating all LNBA range values that are included in the DDOR. This includes the assumptions behind general inputs such as discount rates, inflation factors, revenue requirement multiplier and book life. SDG&E to also provide an active spreadsheet that calculates all LNBA metrics used in the project prioritization process (if different than values in the spreadsheet previously listed). Verification: IPE to verify the LNBA values by independently calculating these values using the formula used in the E3 LNBA calculator and the input assumptions provided by SDG&E. Verify that the LNBA values calculated independently using the using the formula used in the E3 LNBA calculator matches reasonably well with those provided by SDG&E.	requested information by September 30.	calculating the LNBA ranges for planned projects and LNBA metric(s) used for prioritization, as well as provide the assumptions behind general inputs such as discount rate, inflation factors, revenue requirement multiplier and book life.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
19	Compare 2021 forecast and actuals at circuit level for selected number of distribution circuits	Perform comparison of forecasted and actual loads for a statistically meaningful number of distribution circuits to be selected by the IPE in conjunction with SDG&E. Roles: SDG&E to demonstrate comparison of forecasted load for the year 2021 from the 2021 GNA/DDOR and recorded data for 2021 from the 2022 Distribution Planning Process. Verification: IPE to review SDG&E demonstrated process, values and compare differences. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF	SDG&E to provide requested information by September 30.	▪ Forecasted data from 2021 DDOR and recorded data from the 2022 Distribution Planning Process

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
	Other IPE Work			
20	Review implementing of planning standard and/or planning process	No further review is planned for the 2022/2023 DIDF cycle.		
21	Review list of internally approved capital projects	No further review is planned for the 2022/2023 DIDF cycle.		
22	Respond to and incorporate DPAG comments	Include in Final IPE Plan.	Complete by November.	
23	Track solicitation results to inform next cycle	Part of IPE Post-DPAG Report follow-on activities in coordination with the IE.	Q3-2022	
24	Treating confidential material in the IPE report	Confidentiality – the following steps will be followed to ensure that the IPE Reports treat confidential material consistent with the rules and procedures of the CPUC:	Target Dates listed in third column are aligned with the	

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		a. Hold an early meeting with IOU (and potentially the ED) to discuss process and for them to flag those items they intend to request Confidentiality treatment and on what basis. IPE may provide feedback to ED in lieu of having the ED attend the meeting with the IOU and IPE. Discussion held by September 15. b. IOU provides public version of any documents[2] for which they will seek confidential treatment prior to period IPE is wrapping up report. Date: October 22, 2020. At this point the IPE should have two sets of documents that were provided by SCE – one that contains documents that can be included in the public version of the report (all confidential information will be redacted) and a second set that has confidential information that is readable, but such information is highlighted to show that it is confidential. This second set would be	2022/2023 DIDF cycle schedule and will be updated in the Final IPE Plan.	

[2] Documents refers to any document provided to the IPE by the IOU that was not included in the IOU's public version of the GNA/DDOR reports. These documents will be included as attachments to the body of the IPE report as required by a CPUC ruling.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		included as part of the confidential version of the IPE Report. c. IPE provides the final two sets of documents to the IOU by October 26 that will be included in the IPE Report for the IOUs final confidentiality review. d. IPE provides the confidential and public versions of the body of the draft IPE Report to the IOU by November 2; the body of the report to include all but the documents provided in previous item) for final IOU confidentiality review. In the public version of the report, the IPE will redact confidential information based on the type of data flagged as confidential by the utility. e. IOU provides comments/markups of documents after final confidentiality review by November 4 from their review of all documents and by November 5 from their review of the two draft IPE report bodies. Markups of the bodies of the report will include marking up the confidential version highlighting what data is designated as		

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		confidential (data that was not previously designated as confidential). f. After review and signoff, the IPE produces final Confidential Report on CPUC schedule and provides to ED and IOU – November 11. Between November 5th and 11th the IPE and IOU work together to produce the final public version of the body of the report to ensure all confidential information is properly redacted in the public version of the report. On November 11th the public version is also provided to the ED and IOU. g. IOU requests CPUC Confidential Treatment using standard procedures. h. IOU files Public IPE Report version on CPUC schedule – DIDF Advice Letters submitted – November 15, 2020 i. IOU files revised Public Report if CPUC rejects any requests for confidential treatment; otherwise, process is complete, and no further action is needed. In the 2021/2022 cycle the IPE Plan was revised to		

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		assist the IPE to avoid using tables, plots, graphs or other data that are included in the IPE DPAG Report that end up needing to be redacted to meet the IOU's requirements. This should help to reduce the amount of redaction in the Public version of the IPE DPAG Report and make it easier for stakeholders to understand it.		

Appendix A CPUC 4/13/20 Ruling Excerpts

Attachment A
Listing of Schedule and IPE-Specific Reforms for the 2020-2021 DIDF Cycle

1. IPE-specific reforms for the 2020-2021 DIDF Cycle are implemented within the IPE Scope of Work presented in Attachment B.

2. IOU contracts with the IPE for the full scope of work identified in Attachment B shall be executed by the IOUs to allow for IPE Plan development to begin as soon as possible, ideally on or before **April 17, 2020**.

3. The IOUs shall work with the IPE and Energy Division to develop IPE Plans specific to each IOU such that the IPE can submit the Draft IPE Plans to Energy Division for review on or before **May 15, 2020**.

4. The IPE scope of work may be modified by Energy Division as needed for the IPE to successfully complete each assignment. The IOUs will promptly submit a Tier 1 Advice Letter to notice changes in scope should a scope change differ significantly from the scope described in Attachment B. Minor changes should not necessitate an Advice Letter filing.

5. As required by Energy Division on an annual basis, Pre-DPAG and Post-DPAG activities may include workshops; new, re-opened, suspended, or modified working groups (e.g., Distribution Forecast Working Group); and IOU presentations and deliverables.

6. During the Post-DPAG period and in consultation with the IPE, Energy Division may identify exemplary GNA/DDOR documentation components, analytical approaches, or data strategies implemented by one or more IOUs and require that each IOU implement the reform in future DIDF cycles.

R.14-08-013, A.15-07-005, *et al.* ALJ/RIM/nd3

Attachment B
IPE Scope of Work for DIDF Implementation

Term

- January 1st each year to July 31st the following year with the term subject to update by Energy Division if needed to support each DIDF cycle.

Pre-DPAG Period

- Develop an ***IPE Plan*** for each IOU describing the GNA/DDOR review process and detailed approach to Verification and Validation of all data used by the IOUs to prepare their DIDF filing materials.
    - Verification and Validation will include a thorough investigation of the following IOU processes, among others:
        - Collecting circuit loadings and performing weather adjustments;
        - Determining load and DER annual growth on the system level;
        - Disaggregating load and DER annual growth to the circuit level;
        - Checking sum of all disaggregated load and DERs against system-level values;
        - Adding incremental known loads to circuit level forecasts;
        - Developing load, DER, and net load profiles and determining net peak loads;
        - Adjusting for extreme weather;
        - Comparisons to equipment ratings to determine if ratings will be exceeded;
        - Incorporating load transfers, phase transfers, correcting data errors;
        - Compiling GNA tables showing need amount and timing; and
        - Following the IOU's planning standard and/or planning process.
    - GNA/DDOR report review will include an in-depth analysis of the following IOU steps, among others:
        - Developing recommended solutions (planned investments);
        - Implementing the IOU's planning standards and/or planning process;
        - Estimating capital costs for planned investments;

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    - Developing list of candidate deferral projects through application of screens (timing and technical);
    - Developing operational requirements;
    - Prioritization of candidate deferral projects into tiers;
    - Calculating LNBA values; and
    - Comparing prior-year forecast and actuals at circuit level for candidate deferral projects.

- Work directly with the IOUs and Energy Division to develop draft plans as needed. Development of the draft IPE Plans may include, among other activities:
    - Meeting with the IOUs and Energy Division to identify and understand each business process and tool used to complete their GNA/DDOR filings.
- Facilitate or participate in stakeholder workshops to receive feedback on the IPE Plans.
- Review and incorporate comments in the final IPE Plans.
- Submit final IPE Plans to Energy Division and the IOUs with recommendations for future improvements to the plans.
- Other technical support assignments as defined by Energy Division to ensure the IPE and Energy Division will receive from the IOUs the data and cooperation necessary to complete the required evaluation of the GNA/DDOR filings.

DPAG Period

- Participate in all workshops and meetings during the DPAG period. Prepare and deliver presentations or handouts as requested by Energy Division (*e.g.*, final IPE Plan presentations).
- Develop an ***IPE Preliminary Analysis of GNA/DDOR Data Adequacy*** for all three IOUs.
- Review any comments on the preliminary analysis that may be received and discuss the results with Energy Division.

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- Facilitate meetings with Energy Division and the IOUs to correct data inadequacies and prepare further documentation and provide technical support as needed.

- Fully implement each IPE Plan as defined in the final IPE Plans.

- Develop an ***IPE DPAG Report*** for each IOU presenting GNA/DDOR review findings and Verification & Validation outcomes.

- Submit the draft reports to Energy Division for review and (if necessary) to the IOUs to check for confidential information that may be included or to clarify specific details.

- Circulate the final IPE DPAG Reports to stakeholders (public and confidential versions).

- Other technical support assignments as defined by Energy Division to ensure the DPAG process is successfully completed.

Sample Size

- The scope of review conducted by the IPE for each IOU process may encompass the full set of circuits/projects or a subset/sample of circuits or projects. Where sampling is determined to be appropriate by the IPE in consultation with Energy Division, the size of the sample set for each case will be determined by the IPE based on the application of engineering judgement.

Post-DPAG Period

- Develop a single ***IPE Post-DPAG Report*** covering all three IOUs; comparing their current and prior filings; evaluating DIDF DER procurement, operational, cost, and contingency planning outcomes; reviewing IOU compliance; and making recommendations for process improvements and DIDF reform.

- Coordinate with and support the Independent Evaluator (IE) with IE activities and the development of IE reports as needed.

- Submit the draft report to Energy Division for review and (if necessary) to the IOUs to check for confidential information that may be included.

- Submit the final report to Energy Division and prepare public versions as needed.
- Support Energy Division with their review of DIDF reform comments, including comments on any IPE tasks.
- Support Energy Division's review of RFO materials and RFO outcomes.
- Attend RFO and procurement meetings and provide technical support as requested by Energy Division.
- Coordinate with the Independent Evaluator to support their evaluation and provide technical support at the discretion of Energy Division.
- Other technical support assignments as defined by Energy Division to develop and evaluate potential DIDF reforms and track and evaluate deferral opportunities that may be subject to ongoing review in other proceedings (e.g., pursuant to General Order 131-D).

List of IPE DIDF Deliverables

1. ***IPE Plan*** for each IOU describing the GNA/DDOR review process and approach to Verification & Validation for the underlying data.
2. ***IPE Preliminary Analysis of GNA/DDOR Data Adequacy*** for all three IOUs.
3. ***IPE DPAG Report*** for each IOU presenting GNA/DDOR review findings and Verification & Validation outcomes.
4. ***IPE Post-DPAG Report*** covering all three IOUs, comparing their filings, reviewing compliance, and making recommendations for process improvements and DIDF reform.

(end of Attachment B)

Submitted by:

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Appendix D Data Requests and Responses

The IPE received many sets of data in response to requests for information to SDG&E. Listed below are the types of data provided. In most cases these data sets are spreadsheets, PDFs, Power Point presentations or Word documents. These documents are provided as separate documents from the body of this report. Please contact the IPE to obtain a copy of these files.

D.1 Data Requests

The IPE made seven data requests through the course of the verification. A complete set of documents obtained through the data request are listed in D.2.

D.2 GNA DDOR List of Responses

- 1.2021 Circuits Peak Loads_Rev2_6.23.22 (public)
- 1.SCADAScrubber Circuit Loads_Rev2_6.23.22 (public)
- 1.Weather Adjustment Factors_Rev2_6.23.22 (public)
- 2. CED 2020 Load Modifiers - Mid Baseline Mid AAEE with CAISO with 2031
- 2. CED 2020 Load Modifiers - Mid Baseline Mid AAEE_Rev1_6.17.22
- 2. CED 2020_SDGE DER Growth Mid Low (Edited High Low EV)_Rev1_6.17.22
- 3. Distribution Forecast Disaggregations_Rev2_6.23.22 (public)
- 4. Specific Loads_Rev2_7.6.22 (public)
- 5. Forecast Shape - 2022 - Circuit A_Rev1_7.11.22 (public)
- 5. Forecast Shape - 2022 - Circuit B_Rev1_7.11.22 (public)
- 5. Forecast Shape - 2022 - Circuit C_Rev1_7.11.22 (public)
- 5. Forecast Shape - 2022 - Circuit D_Rev1_7.11.22 (public)
- 5. Forecast Shape - 2022 - Circuit E_Rev1_7.11.22 (public)
- 5. Forecast Shape - 2022 - Circuit F_Rev1_7.11.22 (public)
- 5. Forecast Shape - 2022 - Circuit G_Rev1_7.11.22 (public)
- 5. Forecast Shape - 2022 - Circuit H_Rev1_7.11.22 (public)
- 5. Forecast Shape - 2022 - Circuit I_Rev1_7.11.22 (public)
- 5a. 2022 SDGE EV Profile (LDEV)_Rev1_7.11.22
- 5a. 2022 SDGE EV Profile (MDHD)_Rev1_7.11.22
- 5b. Circuit A Profile - 2022 - EE & Weather_Rev1_7.11.22
- 5b. Circuit B Profile - 2022 - EE & Weather_Rev1_7.11.22
- 5b. Circuit C Profile - 2022 - EE & Weather_Rev1_7.11.22
- 5b. Circuit D Profile - 2022 - EE & Weather_Rev1_7.11.22
- 5b. Circuit E Profile - 2022 - EE & Weather_Rev1_7.11.22
- 5b. Circuit F Profile - 2022 - EE & Weather_Rev1_7.11.22
- 5b. Circuit G Profile - 2022 - EE & Weather_Rev1_7.11.22
- 5b. Circuit H Profile - 2022 - EE & Weather_Rev1_7.11.22
- 5b. Circuit I Profile - 2022 - EE & Weather_Rev1_7.11.22

- 10. Circuit Transfers_Rev1_9.8.2022 (public)
- 10. Forecast Shape-Circuit J-After Load Transfer_Rev1_9.8.2022 (public)
- 10. Forecast Shape-Circuit J-Before Load Transfer_Rev1_9.8.2022 (public)
- 10. Forecast Shape-Circuit K-After Load Transfer_Rev1_9.8.2022 (public)
- 10. Forecast Shape-Circuit K-Before Load Transfer_Rev1_9.8.2022 (public)
- 10. Forecast Shape-Circuit L-After Load Transfer_Rev1_9.8.2022 (public)
- 10. Forecast Shape-Circuit L-Before Load Transfer_Rev1_9.8.2022 (public)
- 10. Forecast Shape-Circuit M-After Load Transfer_Rev1_9.8.2022 (public)
- 14. Planned Investment Costs_Rev1_9.23.2022 (Public)_Redacted
- 19. Forecasted vs Actual_Rev1_9.30.2022 (public)
- Forecast Shape - Feeder - O (Public)
- Forecast Shape - Feeder - P (Public)
- Forecast Shape Export - A (Public)
- Forecast Shape Export - B (Public)
- Forecast Shape Export - Q (Public)
- IPE Steps 5-9_Summary_2022

resource innovations

Independent Professional Engineer PG&E 2022 DPAG Report

PUBLIC VERSION

Submitted to California Public Utilities Commission Energy Division and PG&E

Date: November 14, 2022

Contents

1. Introduction and Background

Summary of CPUC April 13, 2020 Rulemaking 14-08-013 and Other Rulemakings

The paragraphs that follow summarize the parts of the April 13, 2020, CPUC ruling and other rulings that directly impact the role of the IPE and/or this report.

The April 13, 2020, CPUC Ruling modified the Distribution Investment Deferral Framework (DIDF) process and filings with respect to the Independent Professional Engineer (IPE) scope of work and provided the updated 2020-2021 DIDF cycle schedule. Attachments A and B of the Ruling include a listing of the IPE-specific reforms discussed in the Ruling and the updated IPE scope of work. These Attachments of the Ruling are attached as Appendix A of this report.

In Decision 18-02-004, the Commission adopted the DIDF. Building upon the Competitive Solicitation Framework developed in the companion Integration of Distributed Energy Resources proceeding, the DIDF established an ongoing annual process to identify, review, and select opportunities for third party-owned distributed energy resources (DERs) to defer or avoid traditional capital investments by the investor-owned utilities (IOUs) on their electric distribution systems. Decision 18-02-004 ordered the IOUs to implement the DIDF as an annual planning cycle that would result in the selection of distribution upgrades for deferral through the competitive solicitation of DERs.

The DIDF was implemented in 2018 and 2019 with the expectation that it would be evaluated and revised after each cycle to improve the process. To that end, the assigned Administrative Law Judge (ALJ) issued a Ruling Requesting Answers to Questions to Improve the Distribution Investment Deferral Framework Process on February 25, 2019 (February 25, 2019, Ruling). Based on these comments, the ALJ issued a Ruling Modifying the Distribution Investment Deferral Framework Process on May 7, 2019 (May 7, 2019, Ruling). The parties have proposed additional recommendations for DIDF reform throughout the 2019 DIDF cycle. A Ruling Requesting Comments on Possible Improvements to the 2020 Distribution Investment Deferral Framework Process was subsequently issued on November 8, 2019 (November 8, 2019, Ruling), and the contents of this Ruling further modify the DIDF. A Ruling on May 11, 2020, modified the DIDF filing and process requirements including proposing a number of possible reforms to the DIDF followed by a ruling in June 2021 establishing new reforms and modifying some of those included in the May 11, 2020, ruling.

The CPUC issued Ruling 14-10-003 on 2/12/21 titled Decision Adopting Pilots to Test Two Frameworks for Procuring Distributed Energy Resources that Avoid or Defer Utility Capital Investments. In that ruling the CPUC added two additional procurement mechanisms to the DIDF cycle and spelled out how pilots of these two mechanisms are to be implemented over the next few DIDF cycles. The two new mechanisms are called the Standard Offer Contract, which applies to in front of the meter DERs, and the Partnership Pilot, which applies to behind the meter DERs. The ruling also includes some revisions to the DIDF process and timing which are followed in this cycle's IPE review and this report.

The IPE scope of work outlined in Attachment A provides for improvement to the IPE review process based on comments received and clarifies that the development of IPE review plans for each IOU will be overseen and approved by Energy Division. According to the Ruling, it is important the IPE has sufficient time to prepare the IPE Plans in advance of the GNA/DDOR filings and that after the filings, the IPE has the cooperation and coordination of the IOUs necessary to collect the data needed for review in time to prepare the IPE Preliminary Analysis of GNA/DDOR Data Adequacy and IPE DPAG Report.

The revised IPE scope reflected in Ruling 14-08-013 includes the requirement to develop an IPE Plan that will cover most if not all of the IPE activities. A copy of the Final 2021 IPE Plan for PG&E is included in Appendix C.

According to the Ruling, planning standards that lead to the identification of reliability needs need not be reviewed at this time. Instead, the IOUs should provide the IPE with planning documentation that supports the identification of all reliability needs. At this time, a formal review of IOU planning standards is not required as it could be a significant undertaking. However, the Ruling states that the Energy Division should discuss the 2020 GNA/DDOR filings with the IPE to determine if inconsistencies and shortcomings in the IOU planning standards exist and whether further review should be prioritized for future DIDF cycles.

The April 13, 2020, CPUC Ruling goes on to state to further assist the IPE with DPAG Report completion, a new IPE Post-DPAG Report deliverable is included within the IPE scope of work. The IPE Post-DPAG Report should review and compare overall IOU DIDF compliance and make recommendations for process improvements and DIDF reform.

As stated in the May 7, 2019, Ruling, the IPE shall report directly to Energy Division to prepare its deliverables and conduct its analyses for DIDF implementation. The April 13, 2020, Ruling states the term of the IPE scope of work shall be the entire DIDF cycle, which starts on January 1 each year to plan for Pre-DPAG and DPAG implementation and concludes on July 31 the following year after all RFOs are concluded and all DIDF reforms are implemented. As a result, IPE scopes of work for each DIDF cycle will overlap.

The schedule and milestones established by the April 13, 2020, Ruling and as modified in subsequent rulings are shown below as they apply to the 2022/2023 DIDF cycle.

DPAG Schedule for 2022-2023 DIDF Cycle

Activity	Date
Pre-DPAG	
Pre-DPAG meetings and workshops, including Draft IPE Plans review	May 2022
DPAG	
IOU GNA/DDOR filings	August 15, 2022
IPE Preliminary Analysis of GNA/DDOR data adequacy circulated	September 5, 2022
DPAG meetings with each IOU, Final IPE Plans circulated	September 19, 2022 (week of)
Participants provide questions and comments to IOUs and IPE	September 25, 2022
IOU responses to questions	October 5, 2022
Follow-up IOU meetings via webinar	October 15, 2022 (week of)
IPE DPAG Reports	November 11, 2022
DIDF Advice Letters submitted	November 15, 2022
Post-DPAG	
Provide draft RFO launch materials to Energy Division for approval in consultation with IPE and IE	December 10, 2022
Launch RFOs for DERs	January 15, 2023 (or within 30 days of DIDF Advice Letter approval if approval is after December 15, 2022)

Independent Professional Engineer

The California Public Utilities Commission (Commission) rulings direct Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities or IOUs) to enter into a contract with an Independent Professional Engineer (IPE). The role of the IPE is as previously described.

Through a contract with Nexant, Inc. (now a part of Resource Innovations), PG&E engaged Mr. Barney Speckman [1], PE, to serve as the advisory engineer (referred to as the Independent Professional Engineer (IPE) for the scope described in the April 23, 2020, CPUC Ruling are as modified by subsequent rulings.

This report which meets the requirements included in the CPUC ruling was provided to PG&E in sufficient time to be included in their DIDF Advice Letter.

1.1. IPE Plan

As required by the April 23, 2020 Ruling, the IPE developed an IPE Plan that served to guide the IPE's steps to implement its 2022 DIDF work scope. The plan was developed using a three-step process:

1. In step 1 the IPE developed a draft IPE Plan working with the Energy Division and PG&E by mid-May 2022.
2. The Plan was distributed to the service list and also discussed at the CPUC Distribution Forecasting Working Group meeting - both in an attempt to obtain stakeholder feedback on the plan.
3. Based upon stakeholder feedback received and under the direction of the Energy Division, the IPE revised the plan and made its IPE Final Plan available on September 21, 2022.

A copy of the Final IPE Plan is included as Appendix C.

The IPE Plan covers the business processes that PG&E uses to identify which distribution projects are recommended to proceed to an RFO seeking DER bids to determine if there is a cost-effective non-wires alternative. One of the core purposes of the plan is answer the question - Are the IOUs identifying every project that could feasibly and cost effectively be deferred by DERs?

The business processes in the Plan are organized generally in the order that they are performed. Starting with capturing the peak load values for each circuit for 2021, using the CEC IEPR forecasts to develop utility specific system level values which are then disaggregated to the circuit level adjusted for known loads and then used to determine if there is an overload or other issue during the planning period. For circuits that have a need, a planned project is selected to address one or more needs, capital costs developed for that project, and the planned projects/investments are screened on the basis of their in-service date to develop a list of potential candidate deferral projects. These candidate deferral projects are then prioritized into three tiers using several metrics, with the projects in the first tier normally recommended for solicitation. In this cycle, for the second time, projects were selected from the candidate deferral list to participate in the two CPUC Pilots – the Standard Offer Contract and Partnership Pilot.

[1] Consistent with the CPUC decision, the contract with Nexant Inc. the firm where Mr. Speckman is employed provides for other individuals within Nexant to assist Mr. Speckman to perform the work in the IPE contract provided that these other individuals are also bound by the same confidentiality and conflict of interest requirements that Mr. Speckman is required to meet.

1.2. Definitions of Verification and Validation

As part of the development of the IPE Plan, detailed definitions were developed to clarify the meaning of Verification and Validation as applied to the IPE scope of work. These definitions which are used and applied in all IPE deliverables, are listed below:

Verification – Is a review performed by the IPE during which an independent check is performed to determine if the results produced were developed using data assumptions and business processes that were defined and described by the utility or are based upon standard industry approaches that do not have to be defined and described. In other words, "Did the IOU follow their own processes correctly as defined by the IOU?"

Validation – Is a review performed by the IPE during which an independent assessment is performed of the appropriateness of the approach taken by the utility to perform a task from an engineering, economics, and business perspective. In other words, "Are the processes implemented by the IOU the best way to identify all planned investments that could feasibly be deferred by DERs cost effectively? And to what extent were the IOU methodologies appropriate and effective?"

1.3. Services Considered within the DDOR Framework

The CPUC, in a previous decision[2], approved the four services proposed by the Competitive Solicitation Framework Working Group (CSFWG) and directed the utilities to consider these services in the GNA/DDOR process. The four services as described in the decision are listed below in an excerpt from the decision:

> "The following definitions for the key distribution services that distributed energy resources can provide are adopted for the Competitive Solicitation Framework:
>
> Distribution Capacity services are load-modifying or supply services that distributed energy resources provide via the dispatch of power output for generators or reduction in load that is capable of reliably and consistently reducing net loading on desired distribution infrastructure;
>
> Voltage Support services are substation and/or circuit level dynamic voltage management services provided by an individual resource and/or aggregated resources capable of dynamically correcting excursions outside voltage limits as well as supporting conservation voltage reduction strategies in coordination with utility voltage/reactive power control systems;
>
> Reliability (back-tie) services are load-modifying or supply service capable of improving local distribution reliability and/or resiliency. Specifically, this service provides a fast reconnection

[2] Decision 16-12-036; definitions can be found on Page 8. Link to document below: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M171/K555/171555623.PDF

and availability of excess reserves to reduce demand when restoring customers during abnormal configurations; and

Resiliency (micro-grid) services are load-modifying or supply services capable of improving local distribution reliability and/or resiliency. This service provides a fast reconnection and availability of excess reserves to reduce demand when restoring customers during abnormal configurations."

1.4. Approach to Information Collection

The information reflected in this report was obtained through a number of methods including:

- Conference calls with PG&E held to review material, respond to IPE questions, and perform Verification and/or Validation Demonstration walk-throughs as described in the IPE Plan and whose results are described later in the report.
- Written data requests sent to PG&E regarding their planning process that led to the needs identified in their GNA Report and the projects included in their DDOR Report. Responses from PG&E were made during follow up conference calls or in writing. All written requests and responses were provided through a secure file transfer protocol established by PG&E. A copy of documents provided in response to these requests are included as Appendix D.
- Participation in PG&E's DPAG Webinar (September 22) and its follow up DPAG Webinar (October 21).
- A review of publicly available materials referred to in the discussions with PG&E or materials previously filed with the CPUC.

1.5. Report Contents

The remainder of this report includes the following sections:

- Section 2 – Review of GNA Report which briefly discusses the contents of the PG&E GNA Report, and any significant differences noted in PG&E's reports between the 2022 and 2021 DIDF cycle. Observations, comments, and recommendations that result from the Validation review with respect to the GNA Report are included in this section.
- Section 3 – Review of DDOR Report which briefly discusses the contents of the PG&E DDOR Report, and any significant differences noted in PG&E's reports between the 2022 and 2021 DIDF cycle. Observations, comments, and recommendations that result from the Validation review with respect to the DDOR Report are included in this section.
- Section 4 – Review of Screening and Prioritization which discusses the screening and prioritization process and results. Observations, comments, and recommendations that result from the Validation review with respect to the screening and prioritization are included in this section.
- Section 5 – Review of Candidate Deferral Projects which includes the review of projects that have been placed into the Tiers defined by PG&E. Observations, comments, and

recommendations that result from the Validation review with respect to the placement of projects in the PG&E defined Tiers are included in this section.

- Section 6 – Discussion of Other Topics of Interest. Observations, comments, and recommendations that result from the Validation review with respect to these topics are included in this section.
- Section 7 – Verification completed which reviews the approach and results of the verification performed by the IPE.
- Appendix A – IPE Scope - Excerpt from April 23, 2020, CPUC Rulemaking 14-08-013.
- Appendix B – Comments Received from the DPAG Members and IOU and IPE responses.
- Appendix C – IPE Final IPE Plan – PG&E
- Appendix D – Documents Received

Identifying Confidential Information

There are a number of instances where information is confidential and such information is highlighted in gray in the confidential version of the Report and blacked out (redacted) in the Public Version of the Report. These are data elements that are considered confidential by PG&E because they are entries for projects that meet the 15/15 Rule or are otherwise declared confidential by PG&E. They include, but are not limited to, such things as certain entries in the GNA and DDOR report appendices, screenshots of planning software etc.

2. Review of GNA Report

The GNA Report submitted by PG&E is summarized at a high level below.

2.1. Scope of PG&E's GNA/DDOR Reports

The PG&E Grid Needs Assessment (GNA) Report is a written report including several Appendices, Appendix D: GNA Results - DER Growth Forecast, Appendix E: GNA Results – Demand Forecast and Bank & Feeder Capacity Needs, Appendix F: GNA Results – Reliability/Resiliency Needs and Appendix G: GNA Results – Line Section Capacity and Voltage Needs. These Excel-based workbooks provide the potential grid needs on PG&E's distribution system. A corresponding DDOR Distribution Deferral Opportunity Report (DDOR) was completed summarizing the mitigation efforts required to meet the needs identified in the GNA. PG&E filed its GNA and DDOR Reports on August 15, 2022, as required by the CPUC. Pursuant to the August 30, 2022 Administrative Law Judge (ALJ) Ruling, PG&E filed the DDOR Supplemental Report containing the Known Load Project Tracking Data on October 17, 2022 and the Line Section Capacity and Voltage Needs (Appendix G) and LNBA-Planned Investments – Line Sections (Appendix H) on October 19, 2022.

Summary of PG&E's 2022 GNA Report

The GNA covers all identified substation, distribution circuit and circuit/segment[3] level needs after free or no-cost load transfers have been reflected in load forecasts. The needs listed include among other information, the following:

- Service Required – Capacity, Voltage Support, Reliability (back-tie), Resiliency (Microgrid).
- Primary Driver of Grid Need – driven by Demand Growth, Voltage or Reliability.
- Rating – Element, Rating and Units.
- Deficiencies – in MW, MVAR, or Vpu and %; and
- Anticipated year of need

2.2. Changes to GNA for 2022

PG&E received a Motion for Extension approval on August 30, 2022, to delay publishing of grid needs resulting from line section analyses, which are primarily voltage support and distribution capacity needs. PG&E provided a supplemental filing on October 19, 2022, per the approved Motion for Extension. The GNA and DDOR were not revised because no candidate deferral opportunities were identified in the supplemental filing (due to the application of the timing screen).

[3] Line section needs were provided in a supplemental filing on October 19, 2022.

2.3. GNA Results

2.3.1. Needs and In-service or Operational Dates

A summary of needs and associated in-service or operational dates can be seen in Table 2-1 and Table 2-2, which are tables included in PG&E's GNA Report and duplicated here for convenience.

Table 2-1: Summary of Grid Needs by Distribution Service and Facility Type

Facility Type	Distribution Service				Total
	Distribution Capacity	Voltage Support	Reliability (Back-Tie)	Resiliency (Microgrid)	
Substation/Bank	167	0	5	3	**175**
Feeder	282	0	6	15	**303**
Distribution Line	0	0	11	0	**11**
Totals	**449**	**0**	**22**	**18**	**489**

*Additional Grid Needs and associated Planned Investments resulting from line section analysis will be provided as a supplemental filing on October 17, 2022

Table 2-2: Summary of All Grid Needs by Anticipated Need Date

Anticipated Need Date					Total
2022	2023	2024	2025	>=2026	
327	61	41	40	20	**489**

2.3.2. Distribution Capacity Needs

The majority of the Grid Needs are Distribution Capacity needs. Of the 449 needs in this category, 389 are needed within the next 3 years, leaving 60 capacity needs with Anticipated Need Dates of 2025 or later.

PG&E has two Distribution Capacity Needs, Blackwell Bank 1 and Huron Bank 1, that are designated as DER Driven which are driven by reverse flow from PV solar generation on the distribution system. These needs and proposed planned Investments are discussed briefly in Section 3.

2.3.3. Voltage Support Needs

There are no voltage support needs at the substation, bank or feeder level as seen from Table 2-1. Most Voltage Support Needs are associated with line sections. PG&E received approval on August 30, 2022, for an extension of time to complete its line section analysis. Any Grid Needs and related Planned Investments for line segments were provided in a supplemental filing on October 19, 2021. There were 129 line segment level voltage support needs identified in this analysis. All of the planned projects associated with these needs had an in-service date within the first three years.

2.3.4. Reliability (Back-Tie) Needs

PG&E identified 22 Reliability or Back-Tie Needs. All of these needs had an Anticipated Need Date of 2022. Of the 22 Back-Tie Needs, 11 were needs related to line sections.

2.3.5. Resiliency (Micro-Grid) Needs

PG&E identified 18 Resiliency Needs. All of these needs had an Anticipated Need Date of 2022. Fifteen of the needs were for feeders with greater than 6,000 customers. As mentioned earlier, these needs were categorized as a Reliability Need prior to the 2021 DIDF. PG&E justified this change by stating "In order for a DER solution to provide a reliability benefit in the same manner as reducing customer count on a circuit, a set of customers on the circuit would need to be immediately served by other means during an outage. This can be accomplished by islanding a part of the circuit so that those customers are not affected by the outage." This is consistent with the design goal stated in PG&E's, Guide for Planning Area Distribution Facilities, dated 8/5/18. This guide states "The feeder design goal is to limit the total number of customers to no more than 6,000."

2.4. GNA - Observations, Conclusions and Recommendations

- We observe the total number of Needs, not including the line segment needs, increased from 392 in 2021 to 489 in 2022. The majority of the changes between the 2022 and 2021 GNA were due to Distribution Capacity-related Needs. The number of Reliability and Resiliency Needs were around the same between the two years. At the line segment level, the total number of Capacity and Voltage Needs increased from 217 in 2021 to 306 in 2022.

- In the 2022 GNA, all 60 of the needs were in years 4 and beyond, whereas in the 2021 GNA, only 25 Needs were in these years.

- One potential reason for the increase in number of Needs in the 2022 GNA when compared to the 2021 GNA is the increase in known loads in the first three forecast years, and particularly in the first year of forecast. The Figure 2-1 shows a comparison of the known loads for the first three forecast years between the 2022 and 2021 GNA. The cumulative three year known loads increased from 814 MW to 1320 MW between the 2021 and 2022 GNAs and the first year known loads increased from 301 MW to 893 MW[4]. Figure 2-2 shows the components of the known load growth in the first three forecast years between the 2021 and 2022 GNAs. It can be seen that the known load total MW are almost uniformly higher in all customer sectors (Residential, Commercial, Industrial and Agricultural) when comparing the 2022 values with those from 2021. On a percentage of the total MW basis, the

[4] It should be noted that in the 2021 GNA, PG&E took the average of the service requests for load additions for the first three years and assumed 100% of this average as the known load addition for the first forecast year, 90% for the second and 80% for the third. In the 2022 GNA, PG&E changed its methodology to account for cancellations or delays associated with service requests. PG&E assumed that the known load additions for year 1, 2 and 3 would be 90% of the service requests for load additions for each of those years. This is covered in Section 7.1.2 of this report.

Agriculture and Commercial components are the largest and are also have increased in share of the total.

Figure 2-1: Comparison of the Known Load Additions between the 2022 and 2021 GNAs

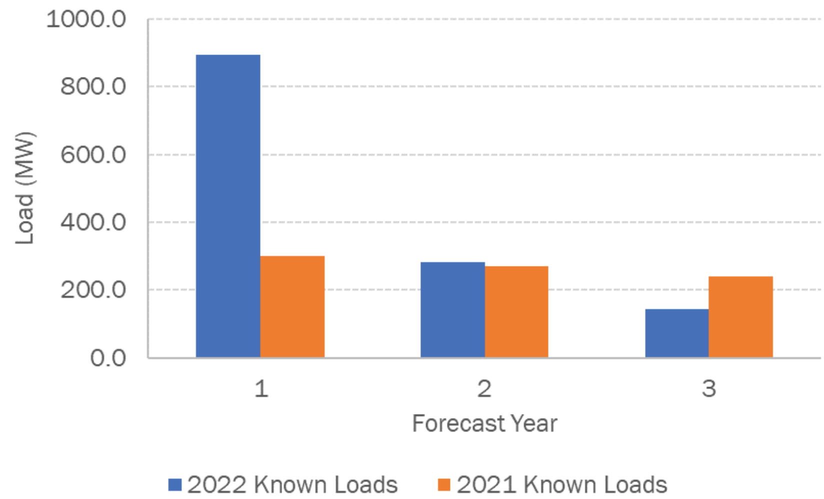
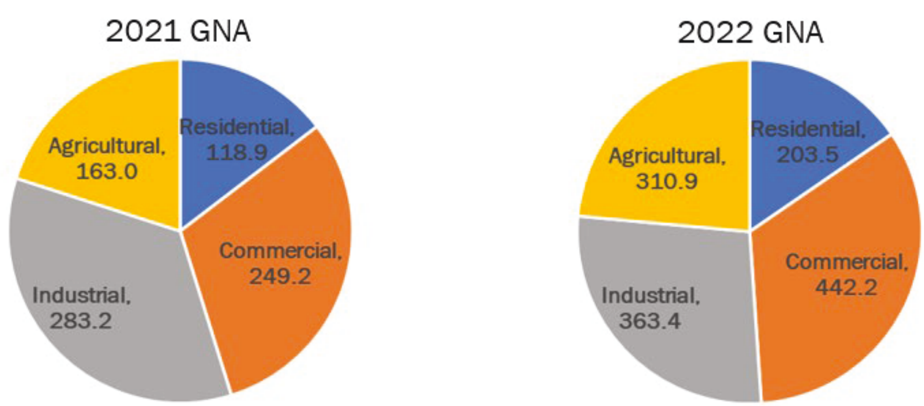


Figure 2-2: Known Load Adjustment Types and Load (MW) in the 2021 and 2022 GNA for the First 3 Forecast Years



- A comparison of cumulative and annual load growth forecasts between the IEPR values and those used in the GNA are shown in Figure 2-3 and Figure 2-4 respectively. As seen in Figure 2-3, the cumulative value of all known loads after three years (1320 MW) is greater than the cumulative IEPR load growth forecast for the same period (812 MW) by around 500 MW. Therefore, the load growth forecast used in the GNA for the first three years is substantially higher than the CEC IEPR forecast load forecast. The GNA and the IEPR cumulative forecasts finally converge in year 10. This is a result of the limited number of applications and therefore new known loads in the later years. As observed in prior years, this approach will likely result in more investment in the earlier years than if the IEPR forecast was used without adjustments. The verification for the calculations performed to develop the GNA load forecast can be found in Section 7.1.2.

Figure 2-3: Cumulative load forecast for the 10-year period

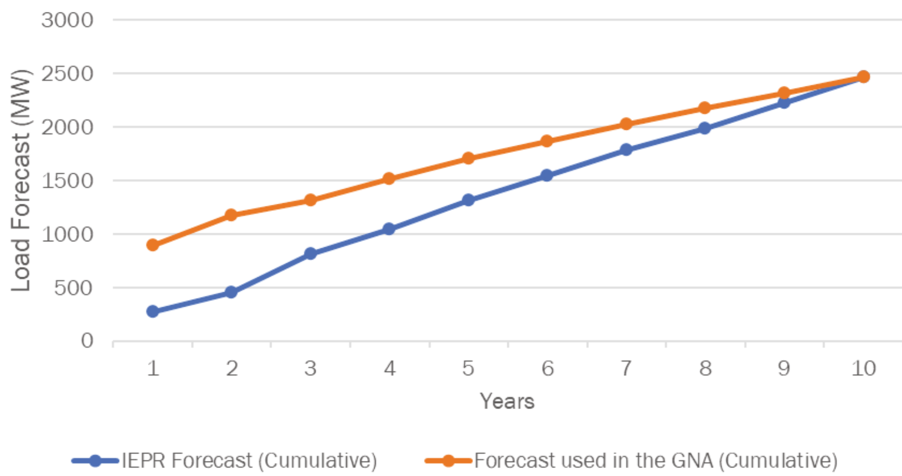
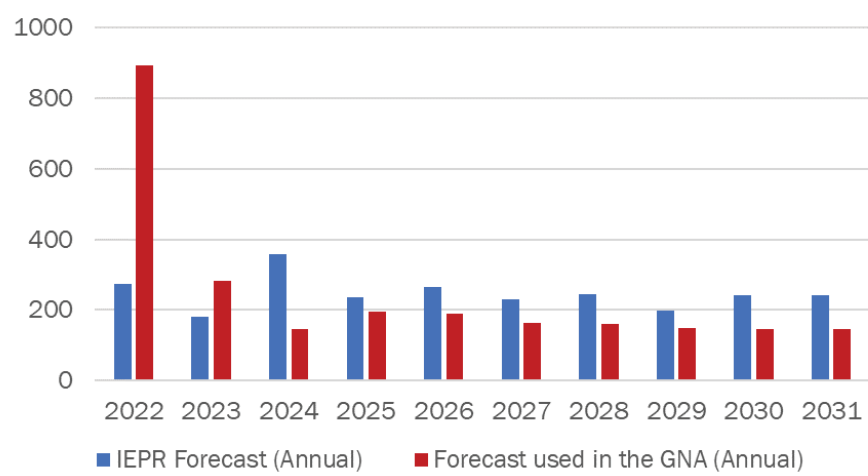


Figure 2-4: Annual load forecast for the 10-year period



- Starting with GNA 2021, PG&E has identified circuits with more than 6000 customers as a resiliency need with the reasoning that a non-wire solution would require some customers to be served by a microgrid during an outage. This need is driven by a specific planning criterion for PG&E that states circuits should not serve more than 6,000 in order to limit the impact of circuit outages. Similarly, PG&E considers emergency bank loss that results in unserved load after exhausting all available transfers as a resiliency need since an NWA solution would require a microgrid. Based on an initial review, it appears that the identification of resiliency needs is not consistent across the utilities. The IPE plans to review the approaches used by the three IOUs in identifying and addressing resiliency needs in the IPE Post-DPAG report. Based on this review, recommendations may address 1) the appropriateness of including resiliency needs in the GNA, 2) revisions to the definition of resiliency, if included in the GNA, and 3) the types of resiliency projects that are deferrable.

- With California's goal of 100% zero-emission vehicles by 2035, it can be reasonably expected that the transportation-related loads will increase in the near future. It is not only important for the utilities to know the location, timing and peak load impact of these new loads, but also have this information as far in advance as possible to make sure any grid needs are addressed in a timely manner in order to support California's zero-emissions goal. It is important for utilities to engage with charging station developers and fleet operators and others developing transportation related projects to have the most up-to-date information on their plans. The IPE plans to investigate how the utilities currently engage with these constituents and report the findings in the IPE Post-DPAG report.

3. Review of DDOR Report – Planned Investments

Using the GNA as the foundation, the DDOR identifies Candidate Deferral Opportunities (CDOs) for potential competitive solicitation for cost-effective Distributed Energy Resource (DER) solutions to mitigate the identified distribution system needs. The DDOR also includes descriptions of the methodology used to prioritize CDOs for potential solicitation and procurement and the methodology used to identify CDOs for inclusion in the two pilot frameworks for procuring DERs, the Partnership Pilot and the Standard Offer Contract (SOC) Pilot.

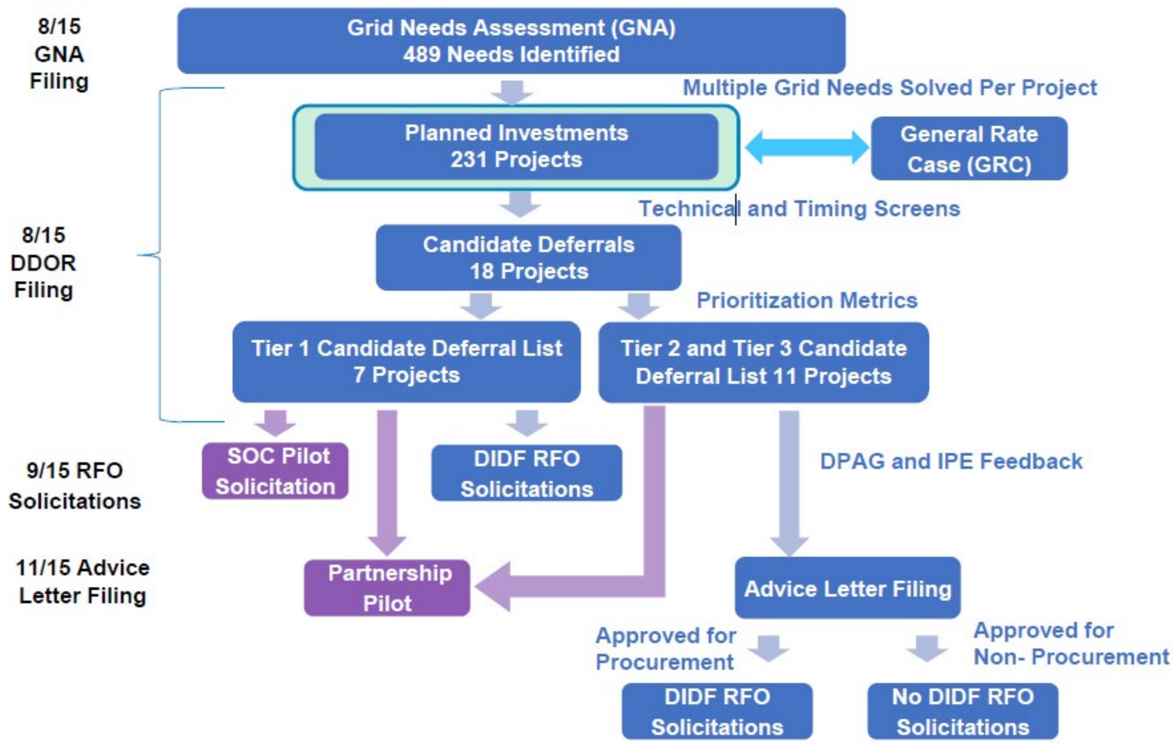
The PG&E DDOR report covers all needs identified in the GNA and includes an Appendix with five Excel-based workbooks each containing several tabs: Appendix A: Planned Investments and Appendix B: Candidate Deferral Opportunities, with tabs for “Planned Investments” and “Candidate Deferral Opportunities”; Appendix C: Prioritization Metric Workbook with tabs for “Tiers Summary, “Introduction”, “Prioritization Metrics Template”, “Candidate Deferral Inputs”, ”LNBA Inputs”, and “Certainty Score”; Appendix D: LNBA Workbooks for Candidate Deferral Opportunities with tabs “Overview”, “General Inputs”, “LNBA Results – Candidate Deferrals ”, and “Project Specific Inputs”; Appendix E: LNBA Workbooks for Planned Investments, and Appendix F: Forecast Uncertainty Questionnaire with tabs for “Assumptions Documentation”, and “Certainty Score”.

The data reflected in these workbooks represents a portion of PG&E’s traditional infrastructure projects that are planned to contribute to the safe and reliable operation of the distribution system and serves as the baseline for evaluating opportunities for DERs to potentially defer or avoid traditional distribution system investments.

The GNA identifies 489 grid needs and since projects often fulfill multiple needs, the DDOR identifies 231 associated planned projects. The DDOR Appendix C Candidate Deferral Input tab identifies the 18 candidate deferral opportunities that have passed the technical and timing screen. The DDOR Appendix C Prioritization Metrics Template tab summarizes the individual deferral candidates and their respective raw and normalized metric component evaluations. The use of the Prioritization Metrics to prioritize candidate deferral projects is described in more detail later in this report.

The figure below provides an illustration of the process followed by PG&E to identify CDOs based on GNA data.

Figure 3-1: Process to Identify Candidate Deferral Opportunities



A summary of the 231 identified 2022 DDOR Planned Investments that mitigate 418 grid needs can be seen in the following tables from PG&E's DDOR Report. As shown in Table 3 1, distribution line projects (example, line section switches) make up 37% of the projects while feeders, bank and substation projects make up the rest. Additional capacity and voltage related line section needs, and projects were identified and provided supplemental filing on October 19, 2022.

Table 3-1: Summary of Planned Investments by Distribution Planning Region and by Project Type

Distribution Planning Region	Project Type				Total
	Substation/ Bank	Bank and Feeder	Feeder	Distribution Line	
Bay Area	3	4	30	13	**50**
Central Valley	9	18	37	37	**101**
North Coast	2	4	4	6	**16**
North Valley and Sierra	4	5	5	16	**30**
South Bay and Central Coast	3	7	10	14	**34**
Totals	**21**	**38**	**86**	**86**	**231**

** Additional Grid Needs and associated Planned Investments resulting from line section analysis provided as a supplemental filing on October 19, 2022, were identified but not included in this table.*

Distribution capacity service needs make up 90.6% of the service requirements as can be seen in Table 3-2.

Table 3-2: Summary of Planned Investments by Distribution Service

Distribution Service			Total
Capacity	Reliability	Resiliency	
205	14	12	**231**

Additional Grid Needs and associated Planned Investments resulting from line section analysis provided as a supplemental filing on October 19, 2022, were identified but not included in this table.

Table 3-3 shows 92% of the projects or 213out of 231 projects have an in-service or operational date earlier than 2024.

Table 3-3: Summary of Planned Investments by In-Service Date

In-Service Date					Total
2022	2023	2024	2025	2026	
97	75	41	18	0	**231**

IOU Ownership

PG&E stated that it does not have any DER solutions planned for IOU ownership for PG&E's list of Planned Investments in PG&E's 2022 DDOR. The Blackwell Bank 1 Planned Investment was evaluated as a CDO in the 2020 DDOR and bids were sought for IOU ownership for this bank during the 2020-2021 DIDF RFO cycle. No cost-effective bids were received.

DER-Driven Projects

PG&E has two Planned Investments for a DER driven Distribution Capacity need, Blackwell Bank 1 and Huron Bank 1 since the 2019 DIDF cycle. Both Planned Investments are replacements of substation banks because backflow caused by photovoltaic generation on the distribution system is projected to exceed the normal rating of the bank.

For Blackwell Bank 1, PG&E sought bids for IOU ownership in the 2020-21 RFO and no cost-effective bids were received. The Blackwell Bank 1 Planned Investment was also re-evaluated as a Candidate Deferral Opportunity in PG&E's 2021 DDOR, although was not recommended for DER solicitation. Blackwell Bank 1 is again evaluated as a Candidate Deferral Opportunity in PG&E's 2022 DDOR and is recommended for solicitation via the SOC Pilot.

For the Huron Bank 1 Planned Investment, PG&E solicited, contracted, and received approval for a DER solution to address the DER-driven needs in the 2019- 2020 DIDF Cycle. After the DER contract was terminated in November 2019, it was determined that an alternate DER deferral project was not available, and the planned investment (transformer bank) was resumed.

3.1. DDOR Report Planned Investments - Observations, Conclusions and Recommendations

We observe that the total number of substation/bank and feeder projects for 2022 is very similar to the number in 2021 (145 vs. 150). The number of distribution line projects in 2022 was slightly lower when compared to 2021 (86.vs. 104). Please note that these distribution line projects are primarily for addressing capacity, reliability and back-tie needs that have been identified at the substation, bank and feeder level. As mentioned previously, additional capacity and voltage related line section needs, and projects were provided in the supplemental filing.

4. Review of DDOR Report – Screening and Prioritization of CDOs

This section contains a discussion of the process used for screening and prioritizing the candidate deferral opportunities.

4.1. Project Screens

This section contains a discussion of the two screens used by PG&E to develop its candidate deferral project list. The screens, required by D.18-02-004, are a technical screen and a timing screen.

The first screen used is the Technical Screen which is intended to identify all grid needs that could be potentially mitigated by DERs with one of the four distribution services adopted by D.16-12-036, specifically Distribution Capacity, Voltage Support, Reliability (Back-Tie), and Resiliency (Microgrids).

The second screen is the Timing Screen which is intended to ensure cost-effective DER solutions can be procured and implemented with sufficient time to fully deploy and begin commercial operation in advance of the in-service date associated with the planned project. For this DDOR, a 2025 or later in-service date is considered as adequate lead time. Using the Timing Screen, 213 out of 231 projects are screened out. The remaining 18 projects are shown in Table 4-1. As seen in the table, 90% of the projects are substation/bank related, and only 5% each are feeder or distribution line related.

Table 4-1: Summary of Candidate Deferral Opportunities by Project Type and Distribution Planning Region After Screening

Distribution Planning Region	Project Type				Total
	Substation / Bank	Bank and Feeder	Feeder	Distribution Line	
Bay Area	0	2	0	0	2
Central Valley	2	7	1	0	10
North Coast	1	0	0	0	1
North Valley and Sierra	0	1	0	0	1
South Bay and Central Coast	1	2	0	1	4
Totals	4	12	1	1	18

Table 4-2 shows, 94% of the projects provide Distribution Capacity and the remaining 6% of the projects provide Resiliency service.

Table 4-2: Summary of Candidate Deferral Opportunities by Distribution Service After Screening

Distribution Service				Total
Distribution Capacity	Voltage Support	Reliability (Back-Tie)	Resiliency	
17	0	0	1	18

After screening, all the projects have an in-service date of 2025. There are no projects in 2026 or later as shown in Table 4-3.

Table 4-3: Summary of Candidate Deferral Opportunities by In-Service Date After Screening

In-Service Date					Total
2022	2023	2024	2025	2026	
0	0	0	18	0	18

4.2. Project Prioritization

This section contains a discussion of the prioritization process used by PG&E to prioritize its candidate deferral projects along with a discussion of the various metrics and sub-metrics PG&E used in that process.

PG&E used the Prioritization Metrics Workbook Template jointly developed by the three IOUs and approved by the Energy Division on May 18, 2021. As in prior years, the prioritization process included three prioritization metrics – Cost Effectiveness, Forecast Certainty, and Market Assessment. However, some of the sub-metrics and how they were evaluated have changed.

The relative ranking of the individual metrics and each Deferred Candidate Opportunity is identified with a color code as shown in Table 4-4.

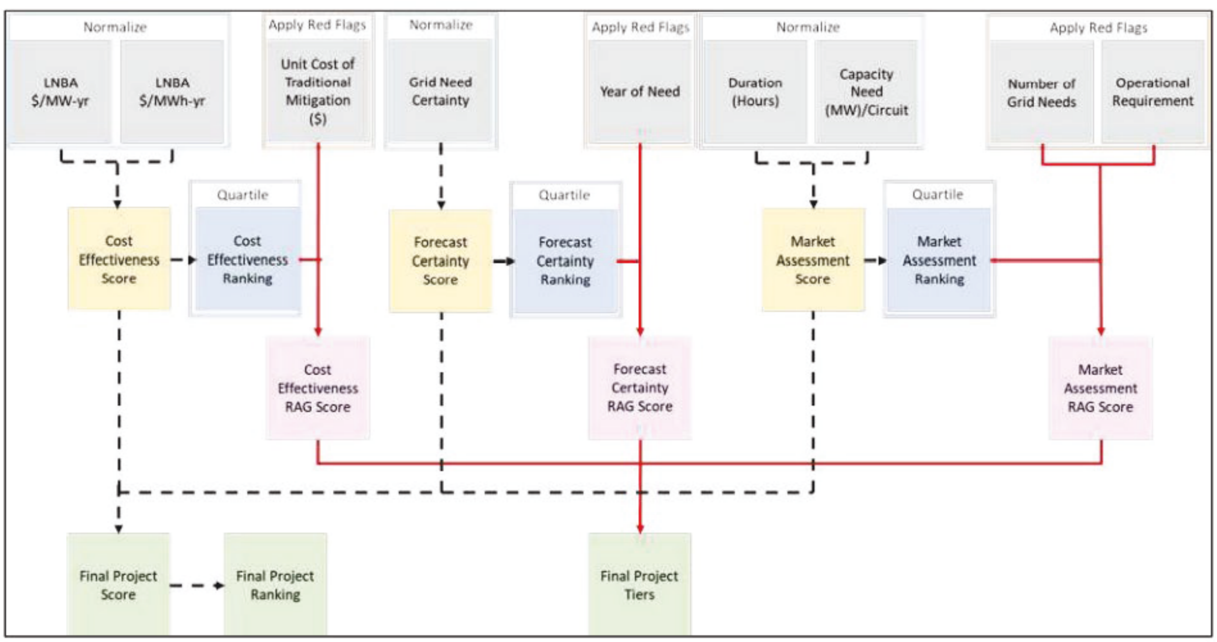
Table 4-4: 3-Tier Prioritization System

Tier	Color Designation	Definition
1		Relatively High Ranking
2		Relatively Moderate Ranking
3		Relatively Low Ranking

All rankings are relative. For example, a higher tiered project does not indicate that the project will be cost effective, have a certain forecast, or have a robust market. It only indicates the ranking of the Candidate Deferral Opportunity relative to other Candidate Deferral Opportunities.

The Joint Prioritization Metrics Workbook Template places CDOs into three tiers based on a step-by-step process, as illustrated in Figure 4-1. The development of the three-prioritization metrics is based on the evaluation of the sub-metrics of each of the three metrics. Each metric has two to four sub-metrics for a total of nine sub-metrics. Five of the sub-metrics are normalized and four are flagged if they don't meet a certain requirement. The five quantitative sub-metrics are normalized first (based on the maximum and minimum values for each sub-metric). The normalized values for each sub-metric are summed[5] to create a score for each Prioritization Metric. Each of the three Prioritization Metric scores are separated into quartiles. The top quartile of Prioritization Metric scores is assigned a "1", the middle two quartiles assigned a "0", and the bottom quartile assigned a "-1". These are known as the Red-Amber-Green (RAG) score. If one of the sub-metrics is flagged for a given Prioritization Metric, that Prioritization Metric is flagged. The total RAG score for each Candidate Deferral Opportunity is then summed across the three Prioritization Metrics. Those with a total RAG score greater than zero are placed in Tier 1; those with a total RAG score of zero are placed into Tier 2; and those with a total RAG score less than zero are placed into Tier 3. As the total RAG score is summed across the three Prioritization Metrics, a Candidate Deferral Opportunity can be assigned a "-1" for one of the Prioritization Metrics (e.g., Forecast Certainty) and still be placed into Tier 1. However, if any of the sub-metrics are flagged, the Candidate Deferral Opportunity will be placed into Tier 3 automatically.

Figure 4-1: Prioritization Metrics, Final Scoring, and Tiering



[5] The Forecast Certainty Metric is based on one sub-metric and therefore is weighted by a factor of 2 (the other Prioritization Metrics have two quantitative sub-metrics summed with equal weighting).

Prioritization Metrics Included in Joint Prioritization Workbook Template

The Cost Effectiveness metric is intended to provide a relative indication of how likely DER resources can cost effectively defer a planned investment. This metric has two quantitative sub-metrics, Estimated LNBA ($/KW-yr.) and Estimated LNBA ($/MWh-yr). The LNBA-related metrics are developed by taking the deferral value for the project and dividing that value by the summation of all maximum MW needs associated with project during the deferral period and the maximum MWh-yr. For the metric evaluation, these two sub-metrics are normalized and added together. For informational purposes only, the Estimated LNBA ($/MWh-day) value for each Candidate Deferral Opportunity is also shown. The MWh-day value is the maximum energy need for the day of the forecasted peak demand. There is also one sub-metric, Cost of Traditional Mitigation, which is flagged if the cost is less than $1 million. The Unit Costs are the estimated project capital costs at the time of the report. This topic is discussed further in Section 7.3.

High tiered CDOs under the Cost Effectiveness Metric are characterized by:

- High unit cost of a traditional solution.
- High LNBA ($/kW-year); and
- High LNBA per MWh of deferral ($/Megawatt-hour (MWH)-year).

The Forecast Certainty Metric is intended to give a relative indication of the certainty of the forecasted grid need. This metric contains two components, a Grid Need Certainty Score and a Year of Need.

The Grid Need Certainty Score is developed from a Forecast Questionnaire (included as Appendix F in the DDOR report), which PG&E revised for this cycle. This questionnaire, completed by local distribution engineers, provides local engineering judgement potentially impacting the certainty of the forecast, such as the health and condition of assets and other activity in the area which may impact the forecast loading. The questionnaire is significantly different from the one used in the previous cycle. See Section 4.2.2 for additional discussion of the Forecast Questionnaire.

The Forecasted Year of Need identifies the earliest Anticipated Need date of all the Grid Needs associated with that particular Candidate Deferral, as derived from the LoadSEER forecast. PG&E considers needs in later years as having more uncertainty. This is a flagged sub-metric that identifies CDOs with a year of need of 2027 and beyond.

High tiered CDOs under the Forecast Certainty Metric are characterized by:

- Nearer term need (2025 vs. 2026); and
- A higher (less negative) Grid Need Certainty Score from the Forecast Questionnaire completed by the distribution engineers.

The third metric, Market Assessment, is intended to give a relative indication of how likely DER resources can be sourced to successfully meet the DER distribution service requirements. This metric has four sub-metrics. Two quantitative sub-metrics, Duration (hours) and Capacity Need (MW/circuit), are normalized and summed. The other two sub-metrics, Operational Requirement (Real Time or Day Ahead) and Number of Grid Needs, are flagged sub-metrics.

For the Duration (hours) sub-metric, a project with shorter duration receives a higher quantitative score. For a CDO with one need location this value would be the CDO's DER duration needs as determined in the planning process. For CDOs with multiple needs the value would be the maximum duration of any of the need locations included in the project.

The Capacity Need (MW) per Circuit sub-metric receives higher quantitative scores for CDOs that have less capacity needed per circuit which can be met by the DER.

The Operational Requirement sub-metric is flagged when the requirement is Real Time because it is believed developers may view a Real Time five-minute dispatch notice to be too difficult and costly to achieve in practice and likely to impact potential revenue streams.

For the Number of Grid Needs sub-metric, a CDO with more than five grid needs are flagged. The reason for this is implementing DER solutions for fewer locations will be easier (and less costly) than implementing DER for many locations.

High tiered CDOs under the Market Assessment Metric are characterized by:

- Day Ahead, rather than Real Time, operational requirement.
- Low number of electric facilities experiencing grid needs in the CDO.
- Shorter duration

As mentioned above, numerical values are determined for each prioritization metric and each of the three prioritization metrics are divided into quartiles based on these scores. Metrics in the first quartile receive a RAG score of one, metrics in the second and third quartile receive a RAG score of 0, and metrics in the fourth quartile receive a score of -1. The three prioritization metric RAG scores for each CDO are summed and those CDOs with a sum greater than 0 are placed in Tier 1; those with a sum of zero are placed in Tier 2; and those with a score of less than zero are placed in Tier 3. Any CDO with a Red Flag is automatically placed in Tier 3.

The results of the application of these three metrics are shown in Table 4-5 below. Using the prioritization table, PG&E has identified 7 Tier 1, 2 Tier 2 and 9 Tier 3 Candidate Deferral Opportunities.

Table 4-5: Preliminary Prioritization Metrics and Rankings of Candidate Deferral Opportunities

Note: This table has confidential information highlighted in gray which will be redacted in the public report

Tier	DDOR ID	Candidate Deferral	In-Service Date	Deficiency (MW)	Cost Effectiveness	Forecast Certainty	Market Assessment
Tier 1	DDOR109	Blackwell Bank 1	6/1/2025		1	0	1
Tier 1	DDOR1001	Camden 1106	5/31/2025		1	1	0
Tier 1	DDOR1007	Carlotta Bank 2	5/31/2025	2.0	0	0	1
Tier 1	DDOR079	Gabilan Bank 2	5/1/2025		1	0	1
Tier 1	DDOR1008	Old River Bank 2	5/31/2025		1	0	1
Tier 1	DDOR1005	San Joaquin Bank 2	5/31/2025		1	1	1
Tier 1	DDOR066	Vasona 1109	6/1/2025		0	1	0
Tier 2	DDOR1029	7th Standard Bank 2	5/1/2025		-1	1	0
Tier 2	DDOR1030	Famoso Bank 1	5/1/2025		0	0	0
Tier 3	DDOR1027	Millbrae Substation	5/2/2025		0	-1	0
Tier 3	DDOR091	Chualar Bank 1	5/1/2025		-1	-1	-1
Tier 3	DDOR105	Lockeford Bank 5	5/1/2025		0	0	FLAG
Tier 3	DDOR102	Montague Bank 2	5/1/2025		-1	0	FLAG
Tier 3	DDOR1026	Ravenswood Substation	4/1/2025	72.5	0	-1	-1
Tier 3	DDOR1031	Semitropic Bank 4	5/1/2025		0	1	FLAG
Tier 3	DDOR1032	Tevis Bank 1	5/1/2025		0	1	FLAG
Tier 3	DDOR1034	Tulucay Bank 4	5/31/2025		-1	-1	0
Tier 3	DDOR1033	Weber Bank 7	5/1/2025		0	0	-1

Please note that the table shown is a revised version provided by PG&E during the DPAG meeting on September 22, 2022. This table includes two minor changes (Cost Effectiveness Score for Carlotta Bank 2 and Market Assessment Score for Millbrae Substation) in the table included in the DDOR report issued on August 16, 2022. However, these changes do not result in the projects identified for procurement in the 2022 DIDF cycle.

4.2.1. IPE Review of Non-Tier 1 CDOs

The IPE believes the Cost Effectiveness metric, in general, is very important to the overall ranking process . If there are insufficient funds or budget to develop and operate a DER solution that is cost effective (one that results in a bid that is below the cost cap) then the other two categories become less important. For this reason, CDOs with high Cost Effectiveness rankings, and not initially recommended by PG&E for one of the DER sourcing mechanisms, were evaluated to determine if they should be considered for procurement.

The IPE performed a Cost Effectiveness (CE) Sensitivity Analysis for all the Tier 2 and Tier 3 projects that had a CE score that was not in the first quartile. The sensitivity analysis answers the question "How much higher does the deferral cost need to be for the CE score for a project to move up in CE ranking to become the lowest project in the top quartile?" The answer to this question is in the form of a multiplier, for example, the deferral cost has to be 2 times higher for the project to be at the bottom of the top quartile for Cost Effectiveness. A low value of multiplier (i.e., 1.2) indicates that a project has a cost effectiveness score that is relatively close to projects in the top quartile. If the other metrics, i.e., Forecast Certainty and Market Assessment are in the second quartile and not flagged, a project with a low multiplier might be worth considering for procurement. Based on this analysis, the IPE found one project (Millbrae Substation) that could be considered for procurement.

4.2.2. Project Prioritization - Observations Conclusions and Recommendations

- Forecast Questionnaire

  The Forecast Certainty Metric contains two components, a Grid Need Certainty Score and a Year of Need. As mentioned earlier, the Grid Need Certainty Score is developed from a Forecast Questionnaire (included as Appendix F in the DDOR report), which PG&E revised for this cycle. In this revised questionnaire, there are six questions and the responses to these questions are assigned a score on a 10-point scale. The Grid Need Certainty score is the sum of these scores. A higher value of Grid Need Certainty score indicates the potential for additional load being added to the circuit that has not been taken into account in the forecasting process. The

  – Q2: Is the area served by the project within two miles of (select one):
    - 0 freeway or highway
    - 1 freeway or highway
    - 2 freeways or highways
    - 3 freeways or highways"

  – Q3: Have you received an inquiry about new load growth application (e.g., fast charging connection) in the area that is not yet reflected in the load forecast?

  – Q4: If you've answered "Yes" in the previous question about new load growth application, please specify the type of load(s) below

  – Q5a-e: What type of project is planned – a) New Substation, b) New Substation Transformer, c) Replaced Substation Transformer, d) New Circuit Breaker, e) Line Work Creates Tie?

  – Q6: What is the asset health risk based on condition for the project and all grid need locations

Response to question Q2 indicates the possibility of additional load growth in the area due to EV charging stations which are likely to locate near highways that are not in the current load forecast. Response to questions Q3 and Q4 also indicate the potential for new load interconnecting to the circuit. The response to question Q5 indicates the scope of the planned project. We assume that a larger project such as a substation gets a higher certainty score since it's most likely to provide the largest amount of margin (capacity in excess of identified need) and thus be able to accommodate the most unforecasted increase in load. Finally, the response to question Q6 indicates the asset health risk for assets in the area. We believe that the rationale behind this question is that if there are assets with a high risk of failure that a non-wires solution would rely on, and thus they are likely to be replaced during the life of the non-wires contract which would make the non-wire project solution moot.

The questions appear to address primarily the possibility of additional load materializing in the area that is not currently in the load forecast. One question is related to the potential failure and replacement of high-risk asset which may undermine DER solution .

The IPE plans to compare the methodology used by the three IOUs for determining the Forecast Certainty score and, as appropriate develop recommendations in the Post-DPAG report.

5. Review of DDOR Report – Pilot Project Selections

Table 5-1 shows the summarizes PG&E's 2022 DDOR Candidate Deferral Opportunities including location, targeted In-Service Date, minimum grid capacity needed (i.e., deficiency), and initially recommended sourcing mechanism.

Table 5-1: Candidate Deferral Opportunities Summary

Note: This table has confidential information highlighted in gray which will be redacted in the public report

Tier	DDOR ID	Candidate Deferral	In-Service Date	Deficiency (MW)	Sourcing Mechanism*
Tier 1	DDOR109	Blackwell Bank 1	6/1/2025		Standard Offer Contract (SOC)
Tier 1	DDOR1001	Camden 1106	5/31/2025		DIDF RFO
Tier 1	DDOR1007	Carlotta Bank 2	5/31/2025	2.0	Partnership Pilot (PP)
Tier 1	DDOR079	Gabilan Bank 2	5/1/2025		Partnership Pilot (PP)
Tier 1	DDOR1008	Old River Bank 2	5/31/2025		DIDF RFO
Tier 1	DDOR1005	San Joaquin Bank 2	5/31/2025		DIDF RFO
Tier 1	DDOR066	Vasona 1109	6/1/2025		Partnership Pilot (PP)
Tier 2	DDOR1029	7th Standard Bank 2	5/1/2025		Not recommended
Tier 2	DDOR1030	Famoso Bank 1	5/1/2025		Not recommended
Tier 3	DDOR1027	Millbrae Substation	5/2/2025		Not recommended
Tier 3	DDOR091	Chualar Bank 1	5/1/2025		Not recommended
Tier 3	DDOR105	Lockeford Bank 5	5/1/2025		Not recommended
Tier 3	DDOR102	Montague Bank 2	5/1/2025		Not recommended
Tier 3	DDOR1026	Ravenswood Substation	4/1/2025	72.5	Not recommended
Tier 3	DDOR1031	Semitropic Bank 4	5/1/2025		Not recommended
Tier 3	DDOR1032	Tevis Bank 1	5/1/2025		Not recommended
Tier 3	DDOR1034	Tulucay Bank 4	5/31/2025		Not recommended
Tier 3	DDOR1033	Weber Bank 7	5/1/2025		Not recommended

PG&E has identified the following 3 Tier 1 candidates for competitive solicitation via the RFO mechanism:

- Camden 1106
- Old River Bank 2
- San Joaquin Bank 2

PSG&E has selected the following Tier 1 CDOs for the Partnership Pilot:

- Gabilan Bank 2
- Carlotta Bank 2
- Vasona 1109

PG&E has selected the following Tier 1 CDO for the Standard Offer Contract (SOC) Pilot:

- Blackwell Bank 1

PG&E provided a demo of the Excel workbook that implemented the logic for selecting CDOs for the Partnership Pilot, SOC Pilot and the RFO. The process used for selecting the candidates for the various procurement mechanisms is described below.

- Screen out CDOs that have any flags or have at least one 24-hour need. This step filtered out 9 CDOs – 4 CDOs that had flags and 5 CDOs that had at least one 24-hour need.
- Determine the trend (MW of the need over time) of the remaining 9 needs. Needs that have a growing MW are suitable for ratable procurement under the Partnership Pilot. The Workbook showed 4 CDOs that had growing needs. Three (Gabilan Bank 2, Carlotta Bank 2 and Vasona 1109) out of the 4 were selected for Partnership Pilot. The remaining CDO (Blackwell Bank 1) was recommended for the SOC Pilot. The reason for this is discussed below.
- Identify CDOs with load profiles that do not have charging constraints. These CDOs are candidates for the SOC Pilot since most FTM NWA resources tend to be energy storage. One CDO (Blackwell Bank 1) was found suitable because it had a single need for reverse flow and no charging constraints.
- The remaining CDOs in Tier 1 were then selected for the DIDF RFO (Camden 1106, Old River Bank 2, San Joaquin Bank 2).

In addition, the selection of the Candidate Deferral Opportunities for the Partnership Pilot was based on the PG&E's application of the following criteria:

1. At least one Tier 1 deferral opportunity and two Tier 2 or Tier 3 deferral opportunities selected.
2. Candidate Deferral Opportunities that could demonstrate Ratable Procurement (e.g., opportunities with low to moderate capacity needs that have incremental procurement goals).
3. Candidate Deferral Opportunities where Ratable Procurement could potentially address the challenge of changing distribution system needs and risk of over and under procurement.
4. Candidate Deferral Opportunities with grid needs occurring within two to five years of Pilot launch.
5. At least one deferral opportunity with a grid need forecast 4 to 5 years out to ensure the subscription period was sufficiently long in duration to test payments.
6. Clusters of deferral opportunities and planned investments.
7. Planned investments that service Disadvantaged Communities (DACs).

The selection of the CDO for the SOC Pilot is based on the Prioritization Metrics discussed above and examination of the following criteria:

- At least one Tier 1 Candidate Deferral Opportunity selected.
- A single Grid Need location to defer the Candidate Deferral Opportunity, in order to facilitate a single Point of Interconnection for an In-Front-of-the-Meter (IFOM) DER solution.
- Indications that there is sufficient capacity at the location of the Grid Need for a DER to charge from the grid, so that IFOM DERs (including energy storage) may be able to charge from the location of need. PG&E notes that this assessment is only indicative, and the DER solution would still need to pursue the interconnection process.
- Earlier In-Service Dates to test the impact of the SOC pilot on the ability of DERs to meet the In-Service Date.
- Candidate Deferral Opportunities with larger Grid Needs (MW), as those needs may be most appropriate for Utility-Scale IFOM DER solutions.

6. Other Items of Interest

6.1. Known Load Project Tracking

The ALJ's June 16, 2022 DIDF Reform order required all three IOUs to track known load projects in the 2022 GNA/DDOR. The reform also required the known load tracking dataset to include a unique project identifier, impacted circuit, initial service request date, load amount, current expected in-service date or indication if service request was cancelled, if appropriate, and type/category of load and, if appropriate, the actual date service was initially provided and the amount. PG&E provided this data as Appendix J in a Supplemental Report filed on October 17, 2022.

The IPE reviewed the data sent by the three IOUs and found that there were various interpretations of the request and different approaches to provide the data. The IPE recommended that a set of definitions similar to the one shown in Table 6-1 be used by all three utilities. The IPE plans to follow up with all three utilities and the Energy Division to better understand the data that is being provided and to ensure that the data will be able to be used to perform the tracking analysis envisioned in the ALJ's June 16th reform order.

Table 6-1: Suggested Definitions for Known Load Project Data Elements

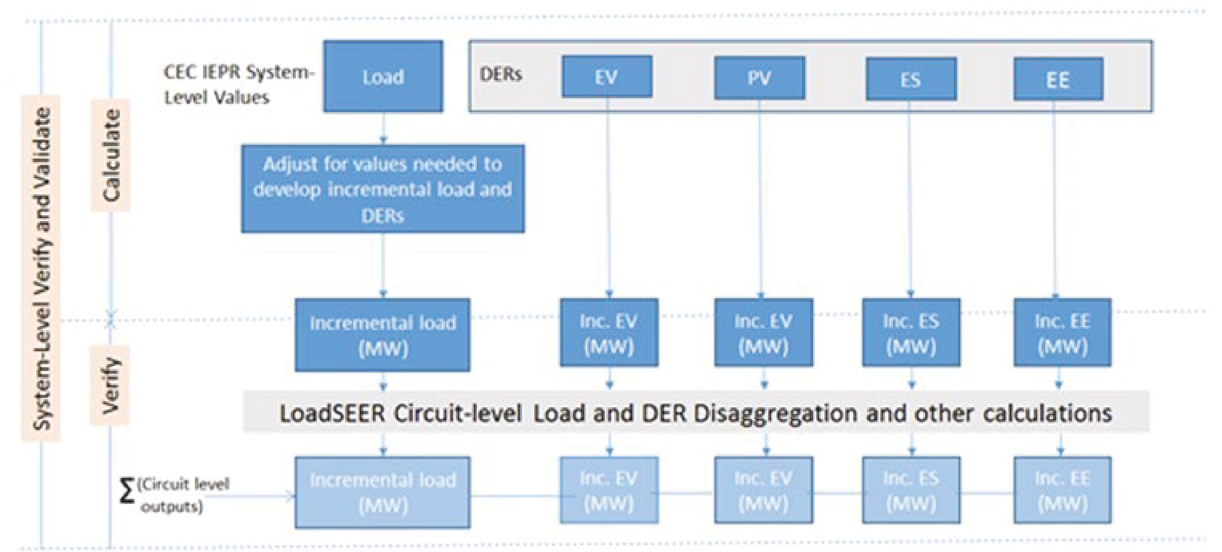
Database Element	Definition
Unique Identifier	This should be a unique identifier associated with each known load. The identifier can be for a new load (no existing meter) or incremental load at an existing customer meter. Only one identifier should be used for each known load even if the load is expected to be served by multiple circuits.
Circuit	This is the name/ID for the circuit(s) that the new load is expected to be served by.
Sector	Residential, Commercial, Industrial or Agricultural
Category	Information on load category such as EV charger, cannabis cultivation, hospital, tract homes etc.
IEPR Status	Embedded or incremental (currently, incremental load only used by SCE).
Load Amount (MW)	This is the load (MW) expected during the peak load hour after adjustments, if any, are made to the load requested by customer. For a new load, this is the peak for the entire load. For an incremental load, it's the peak for just the increment of load requested by the customer. This value should be the same as the value used in the planning process.
Initial Service Request Date	This is the date on which the service request for a new load or incremental load at a customer meter was made. This is not the date that an existing customer first received service. This

	is the date on which the existing customer made a request for an incremental service.
Current Expected In-Service Date	This is the utility planned in-service date associated with the known load. In the case that the known load is an incremental load at an existing business, this date is the date at which service for this incremental load is expected to be provided.
Status	This is the status of the service request that is driving the known load which would be one of the following: in-service, ongoing or cancelled
Actual In-Service Date	This is the date on which the new or incremental service was provided.
Actual Load Amount	The usability of this data will be discussed with the IOUs and this data element will be modified as necessary.

7. Verification Approach and Results

The approach used to verify steps related to load forecasting and checking for circuit overloads is shown in Figure 7-1 and Figure 7-2.

Figure 7-1: System Verification

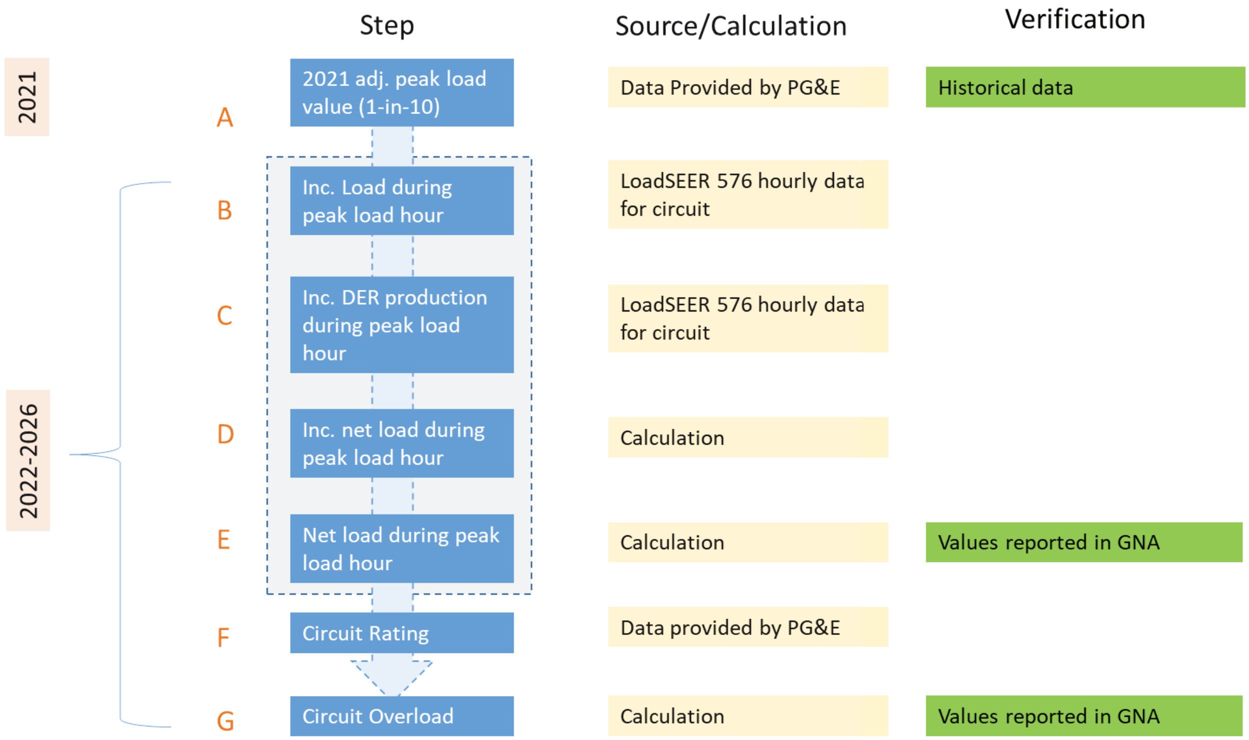


Prior to allocating the CEC IEPR System-Level forecast to distribution circuits, the system load forecast is reduced to account for:

- System-level LDEV,
- System-level Other Private generation,
- Transmission-only load, and
- New known distribution loads.

This adjusted system load is then distributed by customer class and allocated to the circuits in the LoadSEER Geographical Information System geo-spatial load forecasting program created by Integral Analytics. This program is used to model substation and feeder demand forecasts and identify grid needs using satellite imagery and proprietary data analytics to score each acre in PG&E's territory for the likelihood of increased load by customer class. This GIS model also uses historical land aerial imagery to help determine expansion trends that have occurred within specific areas and takes this information into consideration for the acre scoring analysis. The spatial forecasting model is enhanced by utilizing an energy consumption model that is weather normalized and includes economic variables. After area scores are determined, the geospatial program then allocates the CEC customer class load growth projections to each parcel and maps the load growth to feeders based on closest proximity. The output of the geo-spatial program is an annual PG&E peak MW growth by feeder, by customer class for the next 10 years. This growth is then uploaded into the LoadSEER Forecast Integration Tool (LoadSEER FIT) forecasting program. LoadSEER FIT uses customer-class load shapes to turn the system peak growth amount into a 576-hour load shape that can then be applied to the feeder or bank load shape. After the disaggregation of the adjusted system load, the LDEV is reallocated to circuits in LoadSEER based upon propriety algorithms and the new known loads are allocated based upon new application information. The Other Private generation and Transmission-only loads are not disaggregated to individual feeders.

Figure 7-2: Circuit Level Verification



The review includes both a system level review and a circuit level review. The system level review includes:

- The review of the use of the CEC IEPR data to develop top-down load and DER growth forecasts for the planning period.
- This review of CED IEPR data adjustments for such items as transmission customer loads and known new distribution customer loads.
- It also includes a check of the output results of the disaggregation of load and DERs to confirm the aggregate of the outputs at the circuit level (summation of all circuit values) match the input values developed from the CEC IEPR.
- The review performs a number of checks at the individual circuit level for selected circuits. The review checks to see whether the disaggregated load and DERs when integrated, results in the values that are included in the GNA/DDOR reports.

7.1. Processes to Develop System Level Forecasts at Circuit Level

7.1.1. Collect 2021 Actual Circuit Loading, Normalize and Adjust for Extreme Weather – Steps 1 and 8

Monthly peak loads are routinely obtained from SCADA or sometimes from AMI aggregate data or monthly substation meter reads and entered into LoadSEER. The peak load value for the summer months is checked by the Distribution Planning Engineer to ensure it was not associated with a system operating abnormality and is then entered into LoadSEER for 1-in-2 and 1-in-10 load forecasts. If a circuit is identified as subject to temperature variations, LoadSEER adjusts the actual peak load according to the temperature at the time of the peak and generates a 1-in-2 and a 1-in-10 load forecast based on this new adjusted peak load. If the circuit is not identified as temperature sensitive, the starting peak load is not adjusted and the forecast starting point for the 1-in-2 and 1-in-10 forecasts in LoadSEER is the most recent historic peak load. Similarly, the starting point peak load for the 1-in-2 and 1-in-10 forecasts for water-sensitive circuits (i.e., circuits that service pumping loads) are developed. Sixteen circuits that were temperature or water-sensitive were selected for verification. Table 7-1 presents the data collected and reviewed. In addition to the data shown in the table, other information such as 3-day weighted average temperature observed during the peak load hour, as well as the 3-day weighted average temperature for 1-in-2 and 1-in-10 forecasts were provided.

Table 7-1: Data for Circuit Net Load Verification

(Confidential information is redacted in the public report)

Feeder Name/ID	Nominal Voltage (kV)	2021 Peak Date/Time in LoadSEER	2021 Peak Amps in LoadSEER	Weather sensitive? (Was temperature selected as a regression variable?)	Water sensitive? (Was a water variable selected as a regression variable?)	2021 (Amps) Corporate 1-in-2 Temp Adjusted Forecast start point	2022 (Amps) - Final 1-in-2	2022 (Amps) - Final 1-in-10
Llagas 2101/083182101	21	6/17/21 16:00	409	Yes	No	409	432	475
Edenvale 2109/082952109	21	8/28/2021 18:00	403	No	No	n/a	457	504
Wyandotte 1107/102911107	12	7/10/21 19:00	490	Yes	No	462	500	522
Lakewood 1104/013531104	12	9/8/21 18:00	366	No	No	n/a	366	416
Yosemite 0402/022490402	4	9/20/2021 01:00	167	No	No	n/a	168	169
Rincon 1101/043321101	12	6/17/21 19:00	413	Yes	No	408	407	430
Meridian 1102/062541102	12	6/26/21 20:00	293	No	Yes, blend not used	n/a	292	319
Figarden 2102/254552102	21	7/9/21 18:00	493	No	No	n/a	540	566
Anita 1101/102841101	12	6/24/21 20:00	135	No	No	n/a	139	158
Wolfe 1114/083671114	12	6/18/21 16:00	427	Yes	No	414	516	557
Vasona 1102/083771102	12	6/17/21 17:00	438	Yes	No	468	542	607
Atascadero 1101/182541101	12	7/10/21 19:00	536	Yes	No	468	465	508
Manteca 1704/162611704	17	7/10/21 19:00	299	Yes	No	303	379	419
Notre Dame 1104/102041104	12	7/10/21 18:00	420	Yes	No	378	378	405

7.1.2. Determine Load and DER Annual Growth on System Level - Step 2

In this step, the process used by PG&E to determine the system-level peak load and DER forecasts from the CEC IEPR forecasts is verified. Also, the process used by PG&E to model known loads (customer service requests) and spatial loads (difference between system-level peak load and known loads) is verified in this step.

The overall process used by PG&E for determining system level load and DER forecasts is summarized below:

- PG&E uses the peak load and energy forecasts from CED 2020 Forecast, Mid Baseline, Mid AAEE case as the starting point for load and DER forecasts. Since this forecast goes only up to the year 2030, the forecast for 2031 was developed by extrapolating the forecast for the years 2029 and 2030 per CEC's guidance.
- PG&E adjusts the IEPR peak load forecast for the following: transmission-only loads, other private generation and LDEVs. The adjusted forecast is used for determining the annual peak load growth at the system level.
- The annual peak load growth is then allocated to customer classes (residential, industrial, and commercial) proportional to their forecast annual energy consumption.
- Annual known load additions for each customer class are then subtracted from the annual peak load growth calculated in the previous step. The annual known load additions in the first three years used in this process are 90% of the actual known load requests received by PG&E to account for cancellation. The methodology for accounting for cancellation is different from last year where PG&E used 100%, 90% and 80% of the first three-year average known loads for years 1, 2 and 3.
- For calculating the spatial loads for each year, PG&E takes the difference between cumulative annual peak load growth in the 10-year forecast period and the cumulative known loads and spreads the difference evenly from years 4 through 10. These spatial loads are then disaggregated to each circuit using load allocation factors developed by LoadSEER.
- PG&E models the following DERs explicitly: Photovoltaic Solar (PV), Energy Storage (ES), Light Duty Electric Vehicles (LDEV), and Additional Achievable Energy Efficiency (EE). PG&E uses the zonal forecasts for PV, ES, LDEV stock that the CEC provides corresponding to the Mid-Mid case. PG&E also uses bus-bar level EE forecast (low case) provided by the CEC to develop the system-level forecast.
- These system-level DER forecasts are disaggregated to circuits using DER-specific disaggregation methodologies discussed in the GNA report. This is verified in Step 3.

The results of the process used for developing the system-level peak load the process used for modeling the known loads and spatial loads can be seen in Figure 7-3.

Figure 7-3: Peak Forecast Based on CED 2020 Forecast

LINE #		Coincident Peak 1 in 2 (MW)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031 (Extrapolation)
	ANNUAL MW GROWTH OF DISTRIBUTION SYSTEM (2020 IEPR)												
1		*Line 1 of Mid-Baseline IEPR Forecast (2031 extrapolated per CEC gui*	21387	21700	21921	22315	22589	22878	23127	23390	23605	23866	24126
2		*Line 2 of Mid-Baseline IEPR Forecast (2031 extrapolated per CEC gui*	125	164	207	245	285	309	330	350	369	388	407
3		*Line 11 of Mid-Baseline IEPR Forecast (2031 extrapolated per CEC gu*	1157	1145	1133	1122	1110	1099	1088	1077	1066	1055	1044
4			2260	2270	2280	2290	2300	2310	2320	2330	2340	2350	2360
5		*Line 1 minus line 2 minus line 3 minus line 4*	17846	18121	18300	18658	18894	19160	19389	19633	19831	20073	20315
6		*(YearX+1)-(Year X)*		275	180	358	236	266	230	244	197	242	242
7		Running Growth Total (Cumulative MW growth at system peak)		275	454	812	1048	1314	1543	1787	1985	2227	2469
8	CUSTOMER CLASS CONTRIBUTION TO INCREMENTAL PEAK LOAD GROWTH (MW) BY YEAR												
9		Residential allocation 40%		110	72	143	94	106	92	97	79	97	97
10		Commercial allocation 12%		33	22	43	28	32	28	29	24	29	29
11		Industrial allocation 33%		91	59	118	78	88	76	80	65	80	80
12		Agricultural allocation 15%		41	27	54	35	40	34	37	30	36	36
13		Total		275	180	358	236	266	230	244	197	242	242
14	KNOWN ADJUSTMENTS BY CUSTOMER CLASS PEAK LOAD GROWTH (MW) BY YEAR*			90% confidence rate applied to									
15		Known Residential Loads, 2022, 2023, and 2024 applications		143	37	24	4	8	1	1			
16		Known Commercial Loads, 2022, 2023, and 2024 applications		286	100	57	20	20	5	9	2		
17		Known Industrial Loads, 2022, 2023 and 2024 applications		234	100	29	16	14	11	4	1		
18		Known Agricultural Loads, 2022, 2023 and 2024 applications		231	45	35	10			0			
19		TOTAL KNOWN LOAD APPLICATIONS BY YEAR (INCREMENTAL)		894	282	144	49	42	17	14	2	0	0
20		RUNNING TOTAL KNOWN ADJUSTMENTS (CUMULATIVE)		894	1176	1320	1369	1411	1428	1442	1444	1444	1444
21	INCREMENTAL GROWTH BY CUSTOMER CLASS THAT SHOULD BE ALLOCATED TO FEEDERS (CC												
22		RESIDENTIAL		0	0	0	58.56	58.56	58.56	58.56	58.56	58.56	58.56
23		COMMERCIAL		0	0	0	17.57	17.57	17.57	17.57	17.57	17.57	17.57
24		INDUSTRIAL		0	0	0	48.31	48.31	48.31	48.31	48.31	48.31	48.31
25		AGRICULTURAL		0	0	0	21.96	21.96	21.96	21.96	21.96	21.96	21.96
26		TOTAL GEOSPATIAL GROWTH BY YEAR (INCREMENTAL)		0	0	0	146	146	146	146	146	146	146
27		RUNNING TOTAL GEOSPATIAL GROWTH (CUMULATIVE)		0.0	0.0	0.0	146.4	292.8	439.2	585.6	731.9	878.3	1024.7
28													
29	*equals Line 20 plus line 27*	KNOWN ADJUSTMENTS + GEOSPATIAL GROWTH RUNNING TOTAL (CUMULATIVE)		893.5	282.2	144.2	195.3	334.9	455.8	599.4	734.4	878.3	1024.7

7.1.3. Disaggregate Load and DER Annual Growth to Circuit Level – Step 3

PG&E uses the results of the LoadSEER software to disaggregate system-level load and DER forecasts to each circuit. Table 7-2 shows the system-level load forecasts by customer class derived from the CEC IEPR (verified in Step 2) that are an input to this step. Table 7-3 shows the aggregated circuit-level loads by customer class. It can be observed that the load added by customer class by the end of the study period, i.e., year 2031 is the same between the two, but the trajectory is different. In particular, it can be seen that at the system-level, there are no spatial loads in the first three years of the forecast and that the spatial loads increase linearly from 2025 to 2031. This is the target load profile for the spatial loads input into LoadSEER. However, when looking at the aggregate circuit-level spatial loads in Table 7-3, it can be seen that LoadSEER assigns some loads to circuits in the first three years. This has the effect of moving growth from the latter years (2025 to 2031) to the first three years. However, since the load disaggregated to each circuit is small (a total of 262MW in the first three years assigned to over 3000 circuits), this is not expected to increase the number of needs in the first three years by any significant amount. The mismatch between the system-level and aggregate circuit-level spatial load growth was brought to the attention of PG&E and recommended to be fixed in the next cycle.

Table 7-2: System-level load forecasts derived from the CEC IEPR

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Residential	0	0	0	59	117	176	234	293	351	410
Commercial	0	0	0	18	35	53	70	88	105	123
Industrial	0	0	0	48	97	145	193	242	290	338
Agricultural	0	0	0	22	44	66	88	110	132	154
Total	0	0	0	146	293	439	586	732	878	1025

Table 7-3: Aggregated circuit-level load forecasts derived from LoadSEER results

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Residential	33	63	94	187	262	292	323	352	380	410
Commercial	11	22	33	49	65	81	92	103	112	123
Industrial	31	61	91	155	188	219	249	278	308	338
Agricultural	15	30	44	62	77	93	109	123	139	154
Total	89	175	262	453	592	685	772	856	939	1025

Similarly, PG&E disaggregates system-level growth forecasts down to the circuit level for the following four DERs: Additional Achievable Energy efficiency (AAEE), Photovoltaics (PV), Energy Storage (ES), and Electric Vehicles (EV). The IPE verified that the sum of the disaggregated circuit-level forecasts matches with the system-level forecasts provided by the CEC.

Table 7-4 shows a comparison of the disaggregated circuit-level forecasts for AAEE with the system-level forecasts for the Mid-Low case, which is at the WECC busbar level as provided by the CEC. The values shown in this table are incremental, annual AAEE values as opposed to the cumulative values shown in Table 7-3. It can be seen from the table that the two values match very closely except for one year during which AAEE is negative at the system level and assumed to be zero for disaggregation purposes. This mismatch, which is likely due to errors in the bus bar-level CEC forecast was pointed out to PG&E. However, the impact of energy efficiency on peak loads at the circuit level is expected to be small given their magnitude at the system level.

Table 7-4: AAEE forecast verification at the circuit level

	2022	2023	2024	2025	2026	2027	2028	2029	2030
Sum of Circuit-level Forecast	51	125	21	0	39	147	45	42	42
CEC System-level Forecast	51	125	21	-58	39	147	45	42	42

PG&E uses the residential light duty electric vehicle (LDEV) stock forecast from the CED 2020 Mid Baseline case at the zonal level (Zones 1-6) for modeling residential LDEV loads. PG&E used the residential LDEV stock mid forecast provided by the CEC to estimate the counts corresponding to a high EV scenario. PG&E assumed a 20% increase in peak load per unit to account for the LDEV High scenario. The kw per unit was increased from 1.2kw to 1.44kw. .These values are then disaggregated to the circuits based on ZIP code level adoption models developed by PG&E.

PG&E does not use the commercial LDEV stock forecast from CEC, rather uses known load EV additions in place of this. PG&E also does not model MHDEV and electric buses as explicit loads in the GNA. Table 7-5 below compares the System-level residential LDEV peak load derived from the CEC forecast as discussed above with the disaggregated circuit-level peak loads. It can be seen from the table that the two values match very closely.

Table 7-5: Residential LDEV forecast verification at the circuit level

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
CEC System-level Forecast	156	158	150	147	112	111	111	111	115	115
Sum of Circuit-level Forecast	157	155	146	143	108	106	106	106	109	109

PG&E disaggregates the residential and commercial PV solar forecast provided by the CEC at the zonal level (Zones 1-6) to the circuit-level. The IPE verified that the sum of the disaggregated circuit-level forecasts matches with the system-level forecasts provided by the CEC. It can be seen from Table 7-6 that the two values match exactly for residential PV and closely for commercial PV.

Table 7-6: Residential and Commercial PV forecast verification at the circuit level

	2022	2023	2024	2025	2026	2027	2028	2029	2030
	Residential PV Solar								
CEC System-level Forecast (MW)	264	209	186	179	177	176	174	172	172
Sum of Circuit-level Forecast (MW)	264	209	186	179	177	176	174	172	172
	Commercial PV Solar								
CEC System-level Forecast (MW)	192	199	206	214	222	231	241	250	250
Sum of Circuit-level Forecast (MW)	207	214	221	229	238	246	256	265	265

Similar to PV, PG&E disaggregates the residential and commercial energy storage (ES) forecast provided by the CEC at the zonal level (Zones 1-6) to the circuit-level. It can be seen from Table 7-7 that the two values match very closely.

Table 7-7: Residential and Commercial ES forecast verification at the circuit level

	2022	2023	2024	2025	2026	2027	2028	2029	2030
	Residential Energy Storage								
CEC System-level Forecast (MW)	35.07	36.85	38.21	39.30	40.32	41.31	42.28	43.21	44.10
Sum of Circuit-level Forecast (MW)	36.81	38.18	39.27	40.30	41.29	42.23	43.16	44.07	44.07
	Commercial Energy Storage								
CEC System-level Forecast (MW)	8.53	8.53	8.53	8.53	8.53	8.53	8.53	8.53	8.53
Sum of Circuit-level Forecast (MW)	9.80	8.79	8.80	8.46	8.62	9.24	9.53	9.06	8.57

7.1.4. Add Incremental Load Growth Projects to Circuit Level Forecasts – Step 4

PG&E accepts the CEC ten-year forecast and does not assume there are other loads that will connect to the PG&E distribution system not included in that forecast. However, they do identify specific loads they expect with a high degree of confidence will be connected on specific circuits because the developer has submitted an application for service. These make up the "new known distribution loads" adjustment made to the CEC annual system load growth forecast. After the adjusted (remaining) system load is allocated to the circuits, these new known distribution loads are added to their specific circuits. As mentioned earlier, the annual known load additions in the first three years are 90% of the actual known load requests received by PG&E to account for cancellation.

Typical new known distribution loads include loads such as, industrial, commercial, agricultural, and residential projects, cannabis growers, and electric vehicle DC charging stations. This information is obtained from service planning applications for new loads.

As seen in Table 7-8, there is significant expected load growth in all classes of load including EV charging and cannabis growth. The known loads shown in this table match reasonably well with those used in Step 2 (rows 15-19 of Figure 7-3), but don't match the numbers exactly. This is because PG&E continuously updates the list of known loads and list used for Table 7-8, is more current than the list of known loads used in Step 2.

Table 7-8: MW of New Known Distribution Load by year

	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
New Residential	143	37	24	4	8	1	1	0	0	217
New Commercial	286	100	57	20	20	5	9	2	0	498
New Industrial	234	100	29	16	14	11	4	1	0	408
New Agricultural	221	44	35	10	0	0	0	0	0	310
TOTAL	884	281	144	49	42	17	14	2	0	1433

As shown in Table 7-9, the in-service dates for most of the known loads are in first two years of the planning window.

Table 7-9: Count of New Known Distribution Load by Year

	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
New Residential	370	107	35	12	10	2	1	0	0	537
New Commercial	459	85	34	14	10	3	3	1	0	609
New Industrial	230	50	22	9	8	4	2	1	0	326
New Agricultural	560	67	54	4	0	0	1	0	0	686

7.1.5. Convert Peak Growth to 8760 Profile, Determine Net Load and Peak Load – Steps 5, 6, and 7

PG&E uses the circuit-level peak load growth forecast (also called Corporate Forecast) by customer class (verified in Step 3) and 576-hourly profiles from LoadSEER for each customer class to develop the Peak load growth 576 hourly profile for each feeder for each forecast year. This is done using LoadSEER which calculates the 576-hourly load growth profiles at different percentile levels such as P5, P25, P75, and P95. If there are any new known loads assigned to a feeder, these loads are also modeled using standard 576-hourly load profiles for each customer class.

Similarly, PG&E uses the circuit-level DER growth forecast by customer class (if applicable) and standard 576-hourly profile for each DER to develop the DER growth 576 hourly profile for each feeder for each forecast year. The load growth and DER profiles are added to the base load profile to obtain the net load profile for each year. The peak of this net load profile is compared against the rating of the feeder to determine if there are overloads.

In this step, the IPE obtained the 576-hourly load profiles for base load, Corporate and known load growth, and DER growth from LoadSEER for several circuits. These feeders were chosen based on the following criteria:

1. One or more feeders that have sensitivity to temperature and one or more that have sensitivity to water allocation,
2. One or more feeders that have known load (Residential or Commercial) additions,
3. One or more feeders that have identified needs that are solved using load transfer,
4. One or more feeders that have identified needs that are solved with a planned project,
5. One or more feeders with needs that result in Candidate Deferral Opportunity (CDO) project,
6. One or more feeders with known DCFC addition.

The IPE also obtained standard load profiles for new loads by customer class and various DERs by customer class, as applicable. We then used the peak load and DER forecast at the feeder level (verified in Step 3) and the standard profiles to develop our own 576 hourly profiles and compared it with those from LoadSEER. This was done to verify the annual peak loads are being calculated based on the information provided by PG&E.

While this verification was performed on a number of feeders, only the results for Figarden 2102 circuit are presented in this section. This feeder has load growth due to known commercial load addition, as well as growth due to PV, EV, and energy efficiency. Figure 7-4 shows the load profile for a day in January 2022 and 2030 for commercial solar for the Figarden 2012 circuit from LoadSEER. Figure 7-5 shows the same information as calculated by the IPE. As observed, the commercial solar profile calculated by the IPE matches reasonably well with what was produced by LoadSEER. Similarly, Figure 7-6 and Figure 7-7show a comparison of the load profiles for residential LDEVs, and

Figure 7-8 and Figure 7-9 a comparison of energy storage[6]. The figures produced by the IPE match exactly with those from LoadSEER. As mentioned earlier, this circuit also has a known commercial load addition of 2.2 MW. Figure 7-10 and Figure 7-11 show a comparison of the 576-hourly load profiles for new commercial load in 2022 as produced by LoadSEER and as calculated by the IPE. A comparison of the 576-hourly load profile is made since the loads vary by the month and day (weekday vs. weekend).

[6] The comparison of LoadSEER versus IPE calculated load profile for energy storage was made for the Lakewood 1104 circuit since there was no energy storage on the Figarden 1102 circuit.

Figure 7-4: Load profile for Commercial PV for the Figarden 2102 circuit from LoadSEER

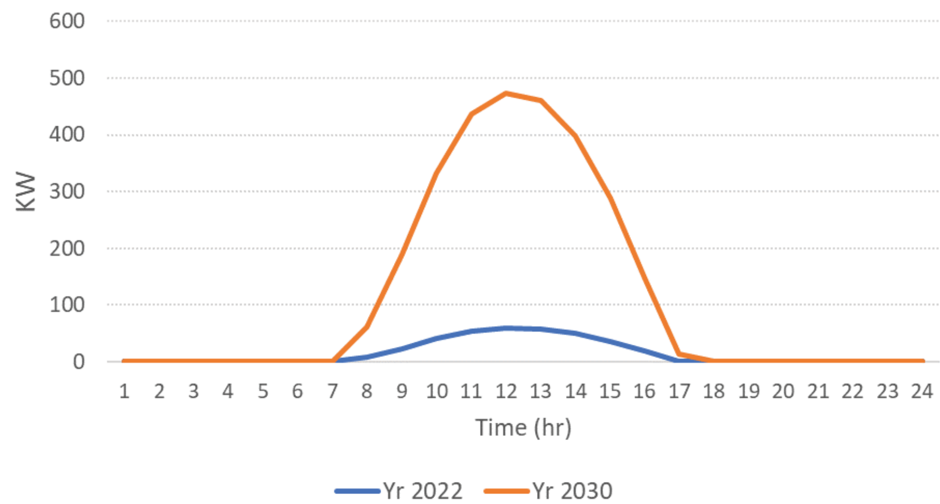


Figure 7-5: Load profile for Commercial PV for the Figarden 2102 circuit calculated by the IPE

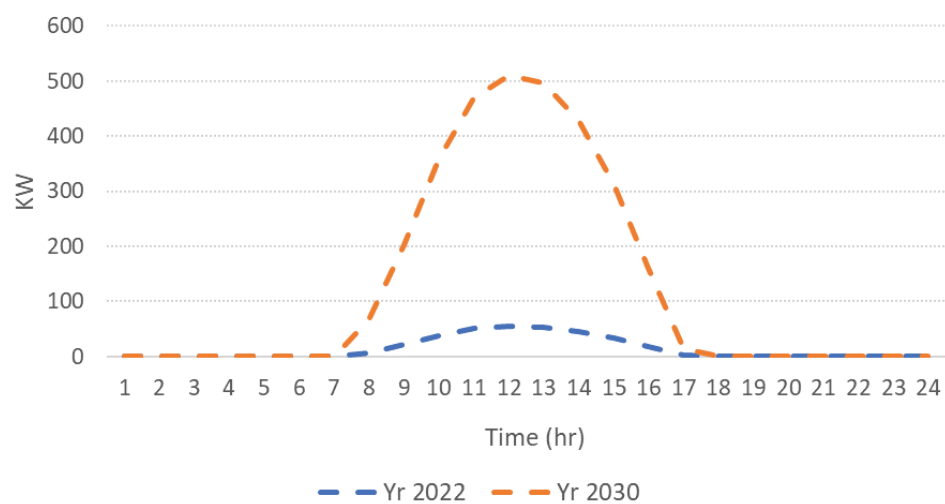


Figure 7-6: Load profile for Residential LDEV for the Figarden 2102 circuit from LoadSEER

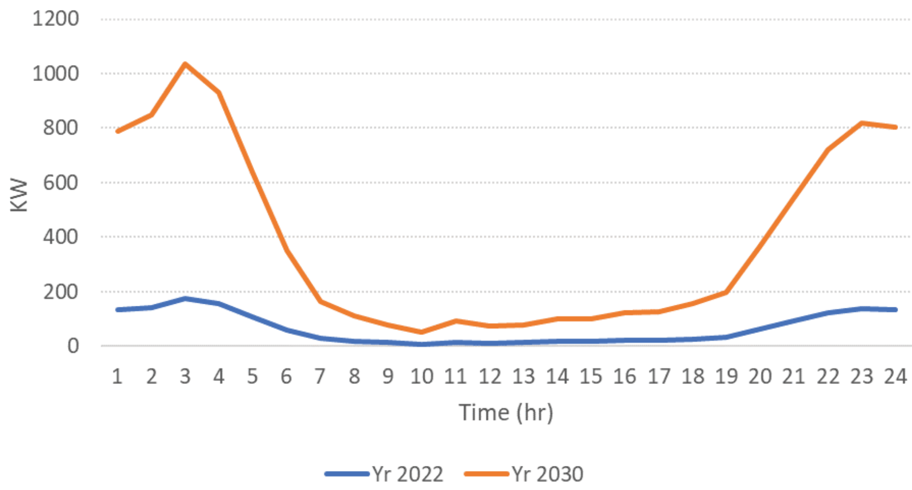


Figure 7-7: Load profile for Residential LDEV for the Figarden 2102 circuit calculated by the IPE

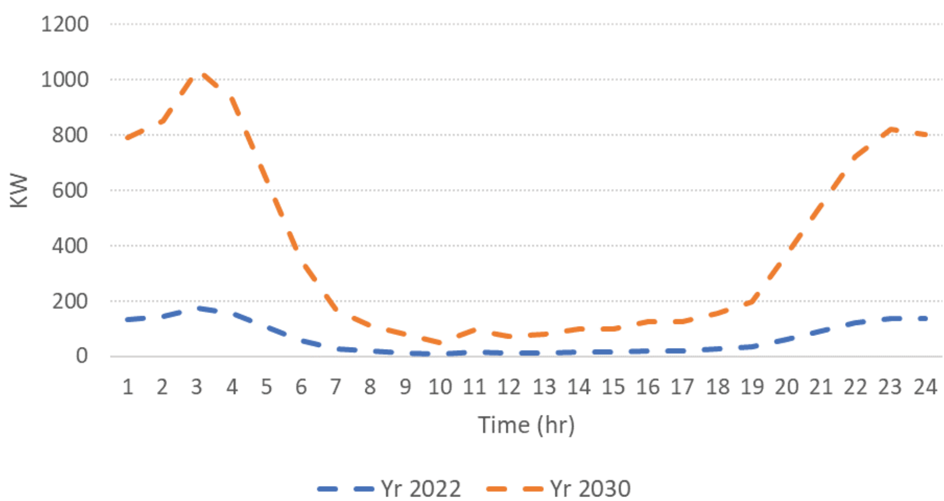


Figure 7-8: Load profile for Energy Storage (Charging) for the Lakewood 1104 circuit from LoadSEER

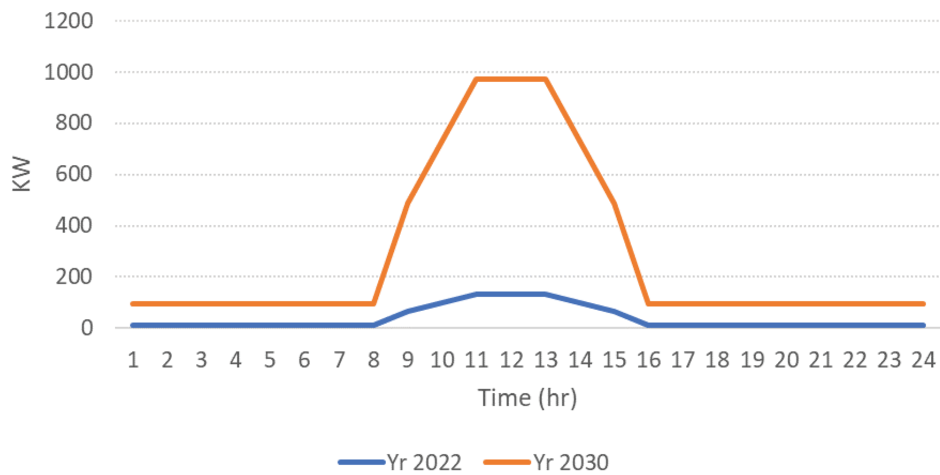


Figure 7-9: Load profile for Energy Storage (charging) for the Lakewood 1104 circuit calculated by the IPE

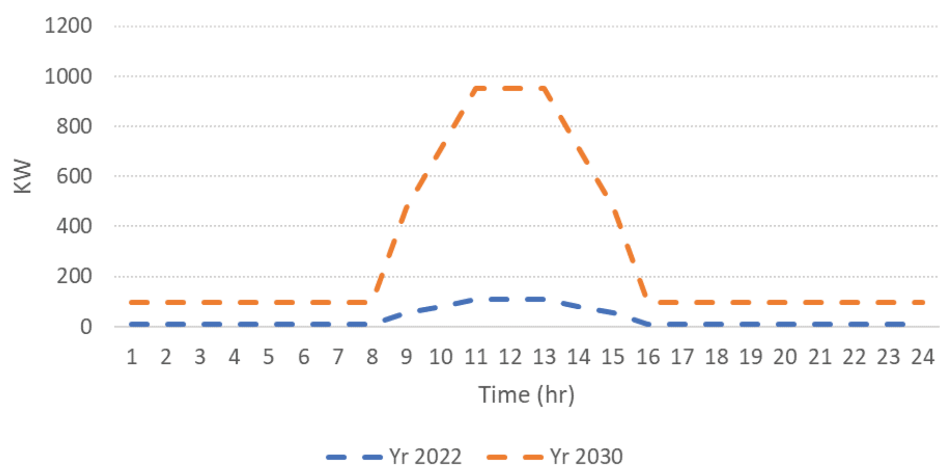


Figure 7-10: Load profile for new commercial load for the Figarden 2102 circuit from LoadSEER

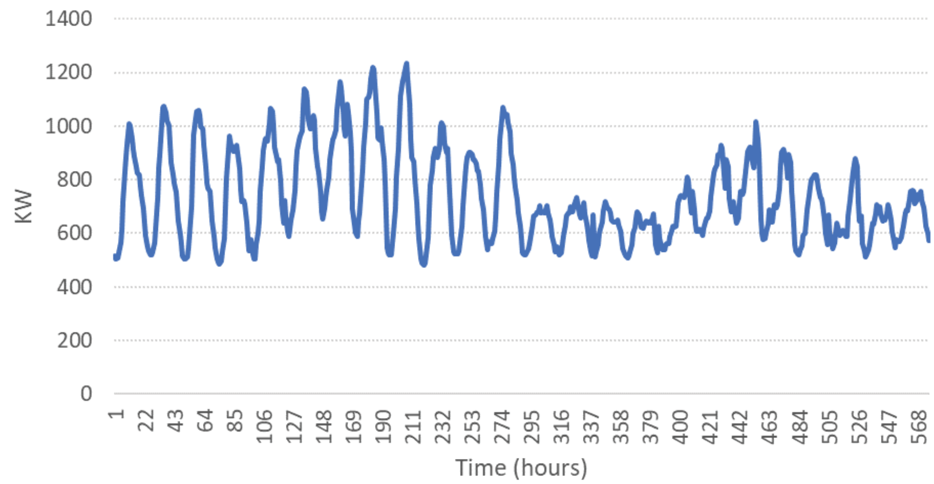
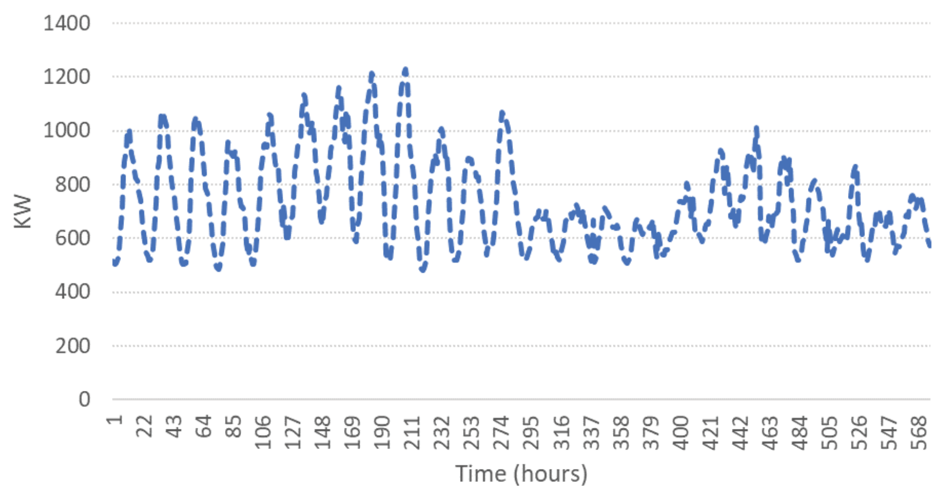


Figure 7-11: Load profile for new commercial load for the Figarden 2102 circuit calculated by the IPE



Since Figarden 2102 circuit does not have any loads due DCFC fast charger, local delivery fleet, or transit agency, other circuits were chosen for this purpose. Figure 7-12 through Figure 7-14 show the EV charging profile for a DCFC, a local delivery fleet and a transit authority from feeders Willows 1101, Barton 1112 and San Luis Obispo 1108 respectively.

Figure 7-12: 24-hour DCFC charger profile

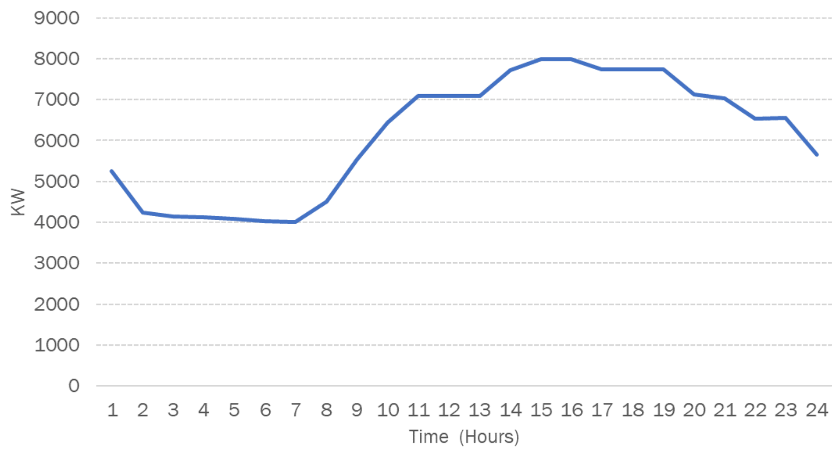


Figure 7-13: 24-hour local delivery fleet charging profile

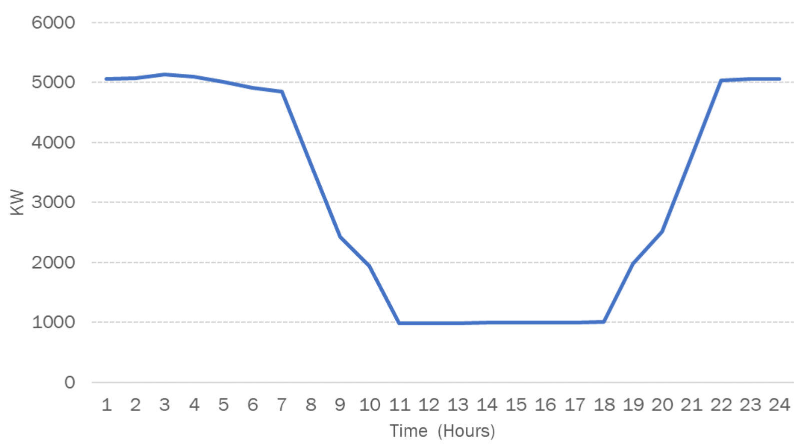
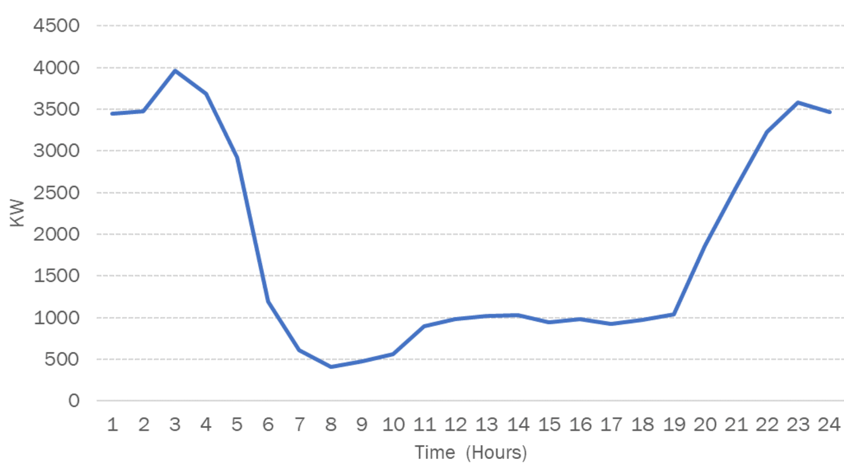


Figure 7-14: 24-hour transit authority charging profile



By using the process described above, the IPE verified the load profiles developed in LoadSEER for load and DER growth. Since the net load is the sum of the base load profile (i.e., existing load) and the growth due to load and DERs, it is reasonable to conclude the net load profile has also been verified by the IPE.

As mentioned earlier, the peak load used for determining circuit and bank overloads is obtained from the peak of the net load profile. Using the 576-hourly data provided by PG&E, the IPE determined the peak load as a percentage of the bank/circuit's rating . Table 7-10 shows the peak load as a percentage of the rate as calculated by the IPE.

Table 7-10: Peak load as a percentage of rating for select circuits as calculated by the IPE

(Confidential information is redacted in the public report)

			Anita 1101		ATASCADERO 1101		EDENVALE 2109		FIGARDEN 2102		LAKEWOOD 1104	
Rating (MW)			11.05		12.19		20.04		21.22		10.76	
	Peak Load (MW)	Over load (%)	Peak Load (MW)	Over load (%)	Peak Load (MW)	Over load (%)	Peak Load (MW)	Over load (%)	Peak Load (MW)	Over load (%)	Peak Load (MW)	Over load (%)
2022			3.39	31%	10.87	89%	18.68	93%	20.98	99%	8.90	83%
2023			3.45	31%	10.76	88%	18.80	94%	23.05	109%	8.97	83%
2024			3.56	32%	10.70	88%	18.96	95%	23.80	112%	9.02	84%
2025			3.67	33%	10.71	88%	19.12	95%	24.01	113%	9.15	85%
2026			3.77	34%	10.72	88%	19.23	96%	24.38	115%	9.21	86%
2027			3.83	35%	10.67	88%	19.30	96%	24.40	115%	9.28	86%
2028			3.94	36%	10.66	87%	19.41	97%	24.41	115%	9.40	87%
2029			4.06	37%	10.65	87%	19.53	97%	24.45	115%	9.51	88%
2030			4.14	37%	10.65	87%	19.67	98%	24.52	116%	9.66	90%
2031			4.26	39%	10.67	88%	19.81	99%	24.56	116%	9.81	91%

7.2. Processes to Determine Circuit Needs and Develop GNA

7.2.1. Initial Comparison to Equipment Ratings, Evaluate No Cost Solutions and Comparison to Equipment Ratings after No Cost Solutions – Steps 9, 10, and 11

PG&E uses no-cost solution such as load transfer to a neighboring circuit before evaluating capital projects. Evaluating potential load transfers involves both LoadSEER and the CYME load flow program. The LoadSEER program provides bank and feeder loading and capacity information, while the CYME load flow program determines loading between sectionalizing devices and identifies any voltage or conductor loading problems. Loads to be transferred between sectionalizing devices are obtained by the Distribution Planning Engineer from the CYME load flow program and entered into LoadSEER for new bank and feeder loading results. The transfers are also reflected in CYME (new loading and circuit reconfiguration) to ensure no line section voltage or capacity problems result.

The data provided by PG&E showed that 630 MW was transferred from one circuit to another in 2022 to relieve overloads. The transfer amount was 150 MW for the 2023 and a total of 60 MW for the years 2024 through 2028. The IPE verified the before and after 576 hourly load profile associated with a transfer of 62 Amps (1.33 MW) from Deschutes 1104 to Oregon Trail 1104 to alleviate overload on Deschutes 1104. Figure 7-15 shows load transfer information including the transfer date, transfer amount and the switching device codes. Figure 7-16 and Figure 7-17 show the 576 profiles from LoadSEER for the two feeders before and after the transfer. It can be clearly seen that there is a 1.3 MW reduction in the loading of Deschutes 1104 and a corresponding increase in the loading of Oregon Trail 1104 after the transfer.

Figure 7-15: Load Transfer Information for Deschutes 1104 to Oregon Trail 1104

Description: Deschutes 1104 to Oregon Trail 1104

Switching: Close 5769 | Open LR 9726

Transfer date: 2022-05-01 ◉ Planned ○ Completed

☐ Exclude from forecast

☐ Requires Project

From:

Type	Name	kV	Amps	MW
Feeder	DESCHUTES 1104	12.47	-62	-1.33

Edit Clear

To:

Type	Name	kV	Amps	MW
Feeder	OREGON TRAIL 1104	12.47	62	1.33

Edit Clear

Customers:

Customer Class	Count
Domestic	0
Commercial	0
Industrial	0
Agriculture	0
Total	0

Comment: mtn6 - This transfer is to alleviate the sum 2022 projected overload on Deschutes 1104.
Free Transfer

Figure 7-16: Loading before and after Transfer for Deschutes 1104

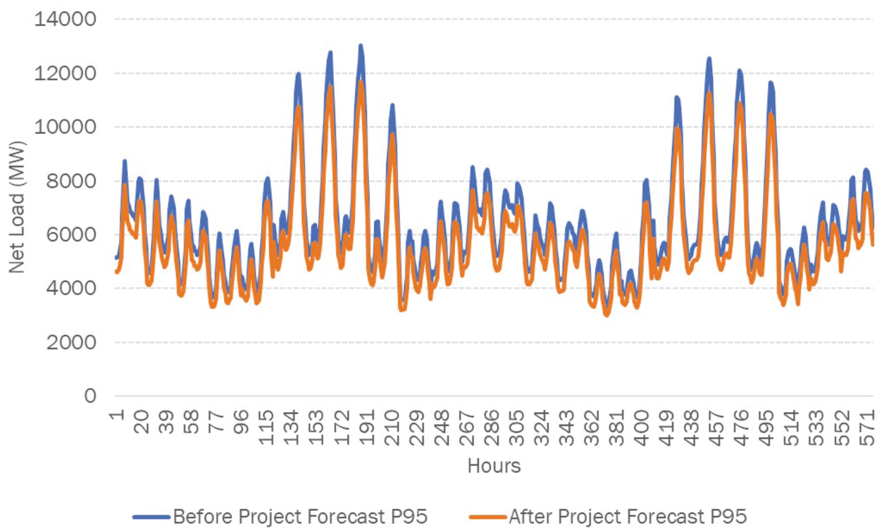
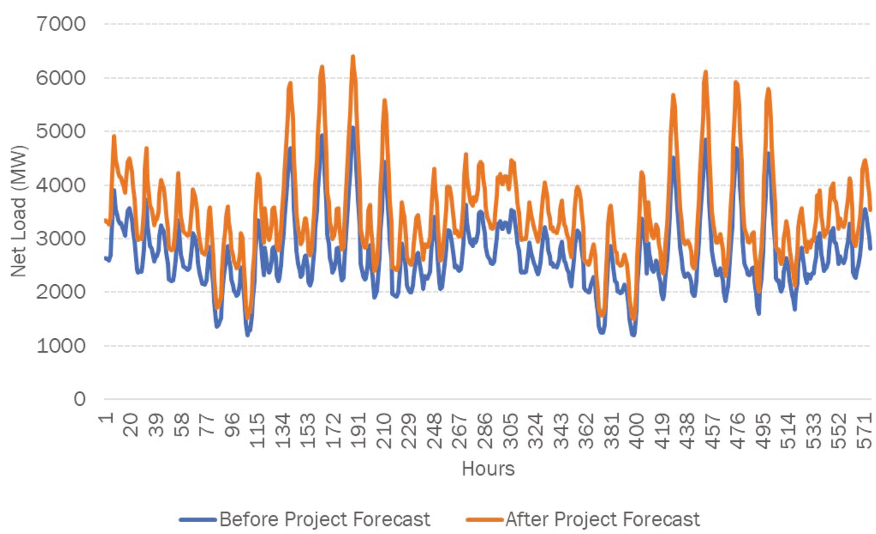


Figure 7-17: Loading before and after Transfer for Oregon Trail 1104



7.2.2. Compile GNA Tables Showing Need and Timing – Step 12

In this step, the IPE compared the loading for select circuit calculated in Step 9 with those reported in the GNA table (Appendix D-F of the GNA Report). Table 7-11 shows the results of the comparison. It can be seen that the values for the loading calculated by the IPE matches exactly with what is reported in the GNA table for the selected circuits. It should be pointed out that the GNA tables show the loading only for the first five forecast years. i.e., 2022-2026.

Table 7-11: Verification of Circuit Loading in the GNA

(Confidential information is redacted in the public report)

			Anita 1101		ATASCADERO 1101		EDENVALE 2109		FIGARDEN 2102		LAKEWOOD 1104	
	Over load calc by IPE (%)	Over load in GNA (%)	Over load calc by IPE (%)	Over load in GNA (%)	Over load calc by IPE (%)	Over load in GNA (%)	Over load calc by IPE (%)	Over load in GNA (%)	Over load calc by IPE (%)	Over load in GNA (%)	Over load calc by IPE (%)	Over load in GNA (%)
2022			31%	31%	89%	89%	93%	93%	99%	99%	83%	83%
2023			31%	31%	88%	88%	94%	94%	109%	109%	83%	83%
2024			32%	32%	88%	88%	95%	95%	112%	112%	84%	84%
2025			33%	33%	88%	88%	95%	95%	113%	113%	85%	85%
2026			34%	34%	88%	88%	96%	96%	115%	115%	86%	86%
2027			35%	35%	88%	88%	96%	96%	115%	115%	86%	86%
2028			36%	36%	87%	87%	97%	97%	115%	115%	87%	87%
2029			37%	37%	87%	87%	97%	97%	115%	115%	88%	88%
2030			37%	37%	87%	87%	98%	98%	116%	116%	90%	90%
2031			39%	39%	88%	88%	99%	99%	116%	116%	91%	91%

7.3. Processes to Develop Planned Investments and Costs

7.3.1. Develop Recommended Solution – Step 13

PG&E has a design criterion, "*Guide for Planning Area Distribution Facilities*" dated 8/15/18 which has been revised to include LoadSEER forecasting, DER inclusion, and GNA and DDOR requirements and timeline. This guideline provides the distribution planners with the explanation and rational for distribution system and component planning, capability of assets, load forecasting, and normal and emergency planning.

The development of two potential CODs were demonstrated for the Millbrae substation project (DDOR 1027) in which a new bank (Bank 2) and a new feeder (1109) are added to decrease the loading on the following banks and circuits: Millbrae Bank 4, Millbrae 1107, East Grand Bank 1 and East Grand 1112. The demo showed that the approach to developing a solution was consistent with the "*Guide for Planning Area Distribution Facilities*".

7.3.2. Estimate Capital Cost for Candidate Deferral Projects – Step 14

Estimated project costs evolve as a project develops and the scope of work becomes more defined. PG&E considers the definition of the CDOs as conceptual with a relatively general definition of scope. They consider the unit cost uncertainty level for all these projects as Class 5 as defined by the American Association of Cost Engineers (AACE).

PG&E considers the CDOs as being at the earlier stages of development and the associated costs are estimated using either estimates of specific equipment and unit costs for work required, or historical costs from completed projects. The costs used for the development of these CDOs are the same costs as used in the GRC.

Cost breakdown for four Tier 1 and one Tier 2 CDOs are shown below in Table 7-12. The costs provided in this table are consistent the costs shown in DDOR Appendix A, Planned Investments.

Table 7-12: Cost Data for Selected Candidate Deferral Opportunities

DDOR ID	PROJECT NAME	PROJECT DESCRIPTION	SCOPE	PROJECT DEVELOPMENT COST
DDOR109	Blackwell Bank 1	Replace Bank 1	Blackwell Bank 1 - Replace existing transformer bank	$ 7,500,000.00
DDOR1001	Camden 1106	Install New Camden 1106 Feeder	Install 2 distribution circuit breakers; Distribution Line Work-16,000 feet of reconductor (1106) and 52,800 feet of reconductor (1107)	$ 13,808,000.00
DDOR1007	Carlotta Bank 2	Replace Carlotta Bank 2	Carlotta Bank 2 - Replace existing transformer Bank	$ 7,500,000.00
DDOR079	Gabilan Bank 2	Install Bank 2	Install new Gabilan Bank 2	$ 13,802,320.00
DDOR1027	Millbrae Substation	Install Bank 2 and Millbrae 1109 Feeder	New Millbrae Bank 2 and 1109 Feeder	$ 18,026,000.00

7.4. Processes to Develop Candidate Deferral List and Prioritize

7.4.1. Development of Candidate Deferral Projects – Step 15

As mentioned earlier, the technical screening is a continuous process. As capacity and/or reliability projects are identified and created, they are entered into LoadSEER which creates a list of grid needs. This LoadSEER list is used as input for capacity projects in the GNA. The need date for capacity projects is identified in LoadSEER and entered in the GNA. Because of project lead times, an in-service date may be later than the need date. In these cases, PG&E must develop a "work around" alternative until the project can be completed.

Line segment overload, undervoltage, and overvoltage conditions are identified from the CYME, PG&E's load flow and voltage analysis tool. Each line segment with an overload or low voltage condition based on the load forecast is entered into the GNA. Normally these conditions are near term and are filtered out by the timing screen. As mentioned earlier, PG&E received a Motion for Extension approval on August 30, 2022, to delay publishing of grid needs resulting from line section analyses, which are primarily voltage support and distribution capacity needs. PG&E provided a supplemental filing on October 19, 2022, per the approved Motion for Extension.

The DDOR in-service dates are used for as the timing screen. There were 18 projects that passed the technical and timing screen. The IPE verified that the technical and timing screen were applied correctly.

7.4.2. Development of Operational Requirements – Step 16

Operational requirements are developed in LoadSEER that provides loading by month and hour for the peak weekday and weekend day of the month. The process used in this year's DDOR is the same as last year's. An hourly profile is developed for the peak weekday and weekend day for the month, identifying the times and duration of any overload.

Since a weekday could be any weekday in the month, it is assumed for the purposes of determining the maximum calls (or days) per month, the DER could be called upon every weekday that month. The same approach is taken for weekend days. Therefore, a need for a DER on one weekday would result in a requirement of approximately 20+ calls per month (depending upon the number of weekdays in the month) and a maximum of approximately 8 calls per month (depending upon the number of weekend days per month) if the overload only occurs during a weekend day.

The LoadSEER results are put into a separate Excel workbook that identifies the service requirements which include the peak year, month ranges, max/min and times and the weekday/weekend needs such as start/end times, load ranges, and potential calls/year. PG&E adds an hour to each side of the overload time to reflect when an overload extends to part of an hour before or after the hour identified by LoadSEER.

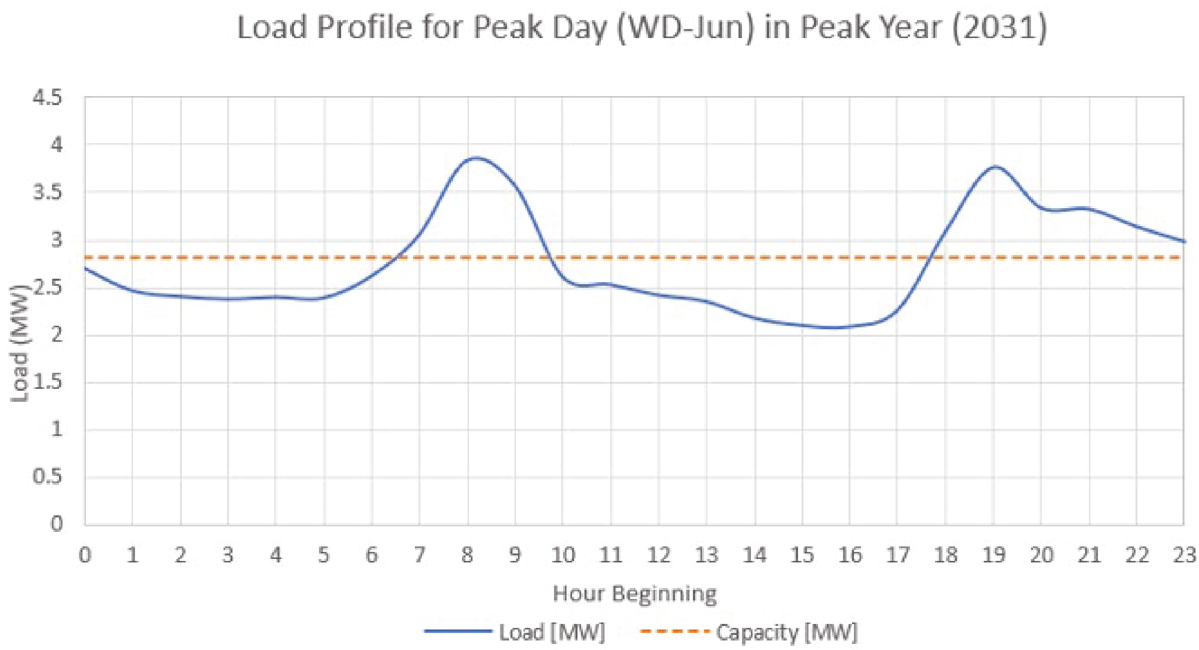
PG&E demonstrated the development of operational requirements for Carlotta Bank 2 – DDOR 1007. In this project, Carlotta Bank 2 is replaced for an overload on Carlotta Bank 1 and Carlotta 1121 feeder. PG&E calculated the operational requirements for the two needs separately. This process involves comparing the 576 Hourly profiles for Carlotta Bank 1 and Carlotta 1121 feeder against their seasonal ratings. The Figure 7-18 below shows the results from this process for Carlotta Bank 1. The top portion of the figure shows the output of the Excel tool that is used for estimating the operational requirements. Quantities such as the need size (MW), the starting and ending months for the need, the starting and ending times and the duration of the need are all estimated. Engineering judgment is the used to fine tune the estimates produced by the Excel tool. This is shown in the bottom half of the figure. Figure 7-19 shows the peak summer day load profile for this circuit. It should be noted that PG&E calculates the operational requirements for all the needs that are associated with CDOs and not just the just the ones selected for procurement.

Figure 7-18: Operational Requirements for Carlotta Bank 1

DER Grid Need (MW)	Grid Need Unit	Starting Need Month	Last Need Month	Calls/Year	Start Time	End Time	Max Need Duration	Peak Year	Number of Events	Anticipated Need Year/First Year
1.02	MW	1	12	365	7:00 AM	12:00 AM	7	2031	2	2025

Grid Need	Grid Need Unit	Month	Calls/Year	Hours	Duration (Hours)	Peak Year	Anticipated Need Year/First Year	WD/WE?
1.02	MW	1-12	365	6 AM-12 AM, 3 PM-12 AM	9	2031	2025	WD/WE

Figure 7-19: Peak Day Load Profile for Carlotta Bank 1



It is observed PG&E has a relatively conservative approach to some of the operational requirements in last year's IPE report, which is repeated here. If there is a peak weekday during the month, it is assumed for the purposes of determining the maximum calls (or days) per month, the DER could be called upon every weekday that month. This is reasonable for identifying potential availability, but we believe it is overly conservative to use it to develop the total number of calls and/or hours for use in the LNBA metrics (LNBA/MWh-yr.). It is unlikely they will be needed for every day of the month. This approach could have an impact on the LNBA metrics resulting in negative rankings for some CDOs. <u>It is recommended PG&E consider an approach that captures the likely distribution over 8760 hours for identifying the number of hours required</u>.

7.4.3. Prioritization of Candidate Deferral Projects into Tiers – Step 17

As part of this step, the prioritization metrics spreadsheet in the PG&E DDOR Report Appendix C: Prioritization Metrics Workbook was used to review the raw data, normalization process, assignment of red flags and final scoring and ranking of the CDOs. The methodology used followed the description provided by PG&E as discussed in detail in Section 5 of this report. The prioritization or assignment of Tiers for the CDOs are consistent with the calculations in this appendix.

7.4.4. Calculate LNBA Values – Step 18

Development and Use of LNBA Values

The Locational Net Benefits Analysis (LNBA) value is the unitized net present value (NPV) of the savings associated with deferring a planned project. The deferral value is the revenue requirement associated with the planned project which includes annualized capital and operations and maintenance (O&M) costs. The LNBA value is typically expressed as a $/MW-year value, determined by dividing the deferral value by the product of two values – the number of years of deferral and the maximum amount (MW) of need during the deferral period. The LNBA value is used as an indicator of the economic feasibility of a non-wire solution. A non-wire solution project with a higher value of LNBA would indicate, in general, that it is a more economically feasible than a project with a lower value. In the DDOR report, actual LNBA values (i.e., not ranges) are reported for both Planned Investments and Candidate Deferral projects. The LNBA values are also used in the calculation of prioritization metrics.

Approach

We reviewed the methodology that PG&E used to develop the LNBA values that it included in its DDOR Report. A summary of that review follows.

Deferral Timeframe

Deferral period is a key input to the LNBA calculation. In the 2022 DDOR, PG&E uses a 10-year deferral timeframe as required by the 2020 May ALJ Ruling Reform #5. For example. If the operating date of a project is in 2025, then the deferral period is 7 years (i.e., defer from 2025 to 2031). PG&E calculated the LNBA values for planned investments (provided in units of $/MW-yr, $/Vpu-yr, or $/MVAR-yr).

LNBA Calculation

The deferral value associated with the deferral of a planned project is the NPV of all the annual deferral values during the deferral timeframe. For example, the 10-year deferral value is the sum of the Net Present Values (NPV) of the 1-year deferral value of the proposed solution for the first ten years. The 1-year deferral value of the proposed solution is the sum of the 1-year deferral value of the equipment capital cost and the operations and maintenance (O&M costs) associated with the new equipment that would have been added if the traditional project had been built. In the E3-based LNBA calculation tool, the deferral value for a multi-year deferral is calculated using a single NPV formula and not as the sum of the NPV of 1-year deferral values as stated above.

The 1-year deferral value associated with equipment is calculated by multiplying the revenue requirement for the project with the RECC factor.

1-Year deferral value = Project Revenue Requirement * RECC,

Where RECC is defined by the following equation:

$$\text{RECC} = \frac{(r-i)}{(1+r)}\left(\frac{(1+r)^N}{(1+r)^N-(1+i)^N}\right)$$

Where, i = assumed inflation over the period of interest, r = assumed discount rate, and N = is the assumed life of the traditional project.

The Project Revenue Requirement is calculated by multiplying the estimated capital cost of the equipment with the Revenue Requirement Multiplier (RRQ Multiplier or RRM). The RRQ Multiplier represents costs recovered from utility customers and includes costs such as taxes, franchise fees, utility authorized rate of return, and overheads. In equation form, the Project Revenue Requirement is:

Project Revenue Requirement = Estimated Project Capital Cost * RRQ Multiplier

If a DER is procured instead of building a traditional wires project, utility customers also benefit by avoiding any annual O&M activities associated with the traditional wires project equipment which is not built. Since O&M is an expense item that is passed to customers in the year it is incurred, it is not multiplied by the RECC factor or the RRM. Since O&M costs are incurred in the year they are performed, O&M cost is also subject to inflation adjustments.

The complete expression of the avoided cost associated with a one-year deferral is thus:

Deferral Benefit = [[Project Capital Cost] x [RECC Factor] x [RRQ Multiplier] + annual O&M]

To calculate the value of a multiple-year deferral, the yearly deferral values for each year, after the first year, are calculated and simply discounted to a present value using a discount factor derived from same discount and inflation rates used in the RECC factor and then the discounted values are summed together to form the multiple year deferral value. The E3-based LNBA calculation tool used by PG&E calculates the multi-year deferral using a single NPV formula with the year of deferral as an input, instead of summing the NPV of 1-year deferrals.

The key assumptions for the LNBA calculation include the following:

- Discount Rate: Derived from the utility’s weighted average cost of capital.
- Inflation Rate: Inflation rates for equipment and O&M as assumed as per utility’s practice.
- Life of a Traditional Project: Assumptions for project life as per utility’s practice.
- Equipment Capital Cost: Cost of the project equipment as per utility’s practice.
- O&M Costs: Cost of O&M as per utility’s practice. Expressed as a percentage of the project’s capital cost.

In general, PG&E’s LNBA calculations followed the same calculations as those included in the E3 LNBA tool. However, PG&E used their own set of assumptions for the key inputs to the deferral calculation. The inputs and outputs of PG&E’s LNBA calculation are discussed below.

Key inputs

The key inputs to the LNBA calculation are shown in the table below. Only the inputs corresponding to substations, primary feeders, and IT are shown in the Table below for simplicity because those were the only ones used. PG&E used a discount rate of 10%. PG&E indicated that the 10% discount rate is equal to PG&E's incremental cost of capital. PG&E's incremental cost of capital is intended to be a forward-looking long-term cost of capital, whereas PG&E's authorized cost of capital is a short-term cost of capital that largely reflects the cost of existing financing, not new or incremental financing. One other key input for the LNBA calculation is the capital cost of equipment for each project.

Table 7-13: Key Inputs for LNBA Calculation

Input	General	Substation Bank	Primary Feeder	Poles and towers	Source
Revenue Requirement Multiplier (Fixed Costs)	145.54%	144.3%	146.8%	150.7%	PG&E assumption
Revenue Requirement Multiplier With O&M	247.78%	186.5%	309.1%	310.5%	PG&E assumption
Equipment Inflation	2.50%	2.50%	2.50%	2.50%	Standard assumption in LNBA Calculator
O&M Inflation	2.50%	2.50%	2.50%	2.50%	Standard assumption in LNBA Calculator
O&M Factor	5.15%	2.13%	8.18%	8.18%	PG&E assumption
O&M Old Eqpt	0%	0%	0%	0%	PG&E assumption
Book Life	46	46	46	44	PG&E assumption
RECC	0.047	0.047	0.047	0.047	Calculated
Discount rate net or project inflation (5/yr.)	4.17%	4.17%	4.17%	4.17%	Calculated

Results

The LNBA values shown in PG&E's DDOR report were verified using the formula shown in E3's LNBA calculator for one of the planned projects (Project ID: DDOR109, GNA Facility Name: Blackwell Bank 1) as shown in Table 7-14. The calculated values (LNBA range) match those provided in the DDOR report for this circuit. In this table, the values from PG&E's LNBA calculation are shown in column 2. The corresponding values calculated using E3's formula, as well as the formula themselves are shown in the 3rd and 4th columns respectively.

Table 7-14: Blackwell Bank 1 Work LNBA Verification

(Confidential information is redacted in the public report)

#	LNBA Item	Values shown in DDOR Report	IPE Calculations based on E3 LNBA formula	E3 LNBA formula
1	Project ID / Name	DDOR109	DDOR109	Input Verified
2	GNA Facility Name	Blackwell Bank 1	Blackwell Bank 1	Input Verified
3	Planned Investment Type	Bank	Bank	Input Verified
4	Project Cost ($k)	7500.00	7500.00	Input Verified
5	Revenue Requirement Multiplier	1.44	1.44	Input Verified
6	Discount Rate (%/yr)	7%	7%	Input Verified
7	Equipment Inflation	3%	3%	Input Verified
8	O&M Inflation	3%	3%	Input Verified
9	O&M Factor	0.00	0.00	Input Verified
10	Book Life	46	46	Input Verified
11	DER Install Year	6/1/2025	6/1/2025	Input Verified
12	Cost year basis	8/1/2022	8/1/2022	Input Verified
13	Analysis Year	2022	2022	Input Verified
14	Deferral Years	7	7	Input Verified
15	Number of no deficiency years after the DER Install yr	0.00	0.00	Input Verified
16	Incremental O&M Cost	0.00	0.00	C4*C9
17	RECC	0.05	0.05	(C6-C7)/(1+C6)*(1+C6)^C10/((1+C6)^C10-(1+C7)^C10)
18	Discount rate net or project inflation (5/yr)	0.04	0.04	(1+C6)/(1+C7)-1
19	RR Install Yr $'s	11607.69*	11554.18	C4*C5*(1+C7)^((C11-C12)/365.25)
20	RR * RECC	548.06	545.56	C19*C17
21	Capital Benefit in Install Year	3405.63	3390.07	PV(C18,C14,-C20,0,1)
22	O&M Deferral Benefit in Install Year	0.00	0.00	PV(C18,C14,-C16,0,1)*(1+C8)^(C11-C12)/(1+C18)^B15
23	Value of Deferral Benefits ($000s) in Install Year			

24	Value of Deferral Benefit ($000s) in 2022			
25	Max Need (MW/Vpu/MVAR)*			
26	Normalized Deferral Benefit ($000s/MW-yr)			

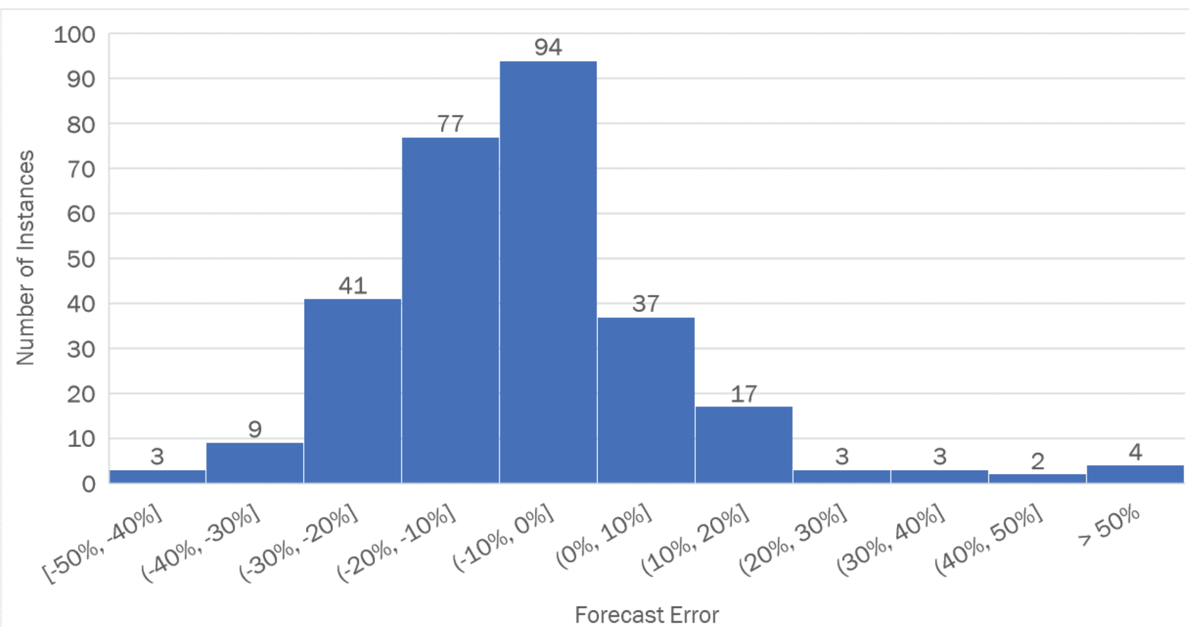
Note: This table has confidential information highlighted in gray which will be redacted in the public report

*The value calculated for revenue requirement by PG&E is slightly different since it takes partial year into account in the present value calculation whereas the E3 LNBA does not.

7.4.5. Compare 2021 Forecast and Actuals at Circuit Level for 2021 – Step 19

A comparison of the actual 2021 peak load (adjusted to 1-in-10) and the 2021 forecasted 1-in-10 peak load from the 2020 GNA was conducted for roughly 10% of the feeders. PG&E provided the 2021 actual scrubbed peak loads adjusted to 1-in-10 and the corresponding forecast was obtained by the IPE from the 2020 GNA appendix. The analysis process included calculation of the delta between the actual and forecasted load, percent difference and overloads. Figure 7-20: Percent Difference Distribution, below shows the percent difference distribution for 291 circuits.

Figure 7-20: Percent Difference Distribution



It can be inferred from the figure that the distribution is a little skewed (forecasts higher than actuals more than actuals higher than forecasts) and that the about 45% of the forecasted loads are within +/-10% of the actual values and about 78% of the forecasted loads are within +/-20% of the actual values.

7.5. Other IPE Work

7.5.1. Respond to and Incorporate DPAG Comments – Step 22

The IPE was available during the PG&E DPAG meeting and the PG&E Follow-Up DPAG meeting to respond to questions raised by stakeholders. There were no written comments or questions directly addressed to the IPE.

7.5.2. Track Solicitation Results to Inform Next Cycle – Step 22

This review was completed in Q3 of 2022. A solicitation tracking tool (XCEL workbook) was developed at the Direction of the Energy Division. The IPE participated in the definition of the data to be tracked. Going forward the IEs for each utility will update the information in the tracking tool on a regular basis.

7.5.3. Treating confidential material in the IPE report – Step 24

The IPE work products have followed the process and steps included in this Business Step in developing its IPE Final Report.

Appendix A IPE Scope

R.14-08-013, A.15-07-005, *et al.* ALJ/RIM/nd3

Attachment A
Listing of Schedule and IPE-Specific Reforms for the 2020-2021 DIDF Cycle

1. IPE-specific reforms for the 2020-2021 DIDF Cycle are implemented within the IPE Scope of Work presented in Attachment B.
2. IOU contracts with the IPE for the full scope of work identified in Attachment B shall be executed by the IOUs to allow for IPE Plan development to begin as soon as possible, ideally on or before **April 17, 2020**.
3. The IOUs shall work with the IPE and Energy Division to develop IPE Plans specific to each IOU such that the IPE can submit the Draft IPE Plans to Energy Division for review on or before **May 15, 2020**.
4. The IPE scope of work may be modified by Energy Division as needed for the IPE to successfully complete each assignment. The IOUs will promptly submit a Tier 1 Advice Letter to notice changes in scope should a scope change differ significantly from the scope described in Attachment B. Minor changes should not necessitate an Advice Letter filing.
5. As required by Energy Division on an annual basis, Pre-DPAG and Post-DPAG activities may include workshops; new, re-opened, suspended, or modified working groups (e.g., Distribution Forecast Working Group); and IOU presentations and deliverables.
6. During the Post-DPAG period and in consultation with the IPE, Energy Division may identify exemplary GNA/DDOR documentation components, analytical approaches, or data strategies implemented by one or more IOUs and require that each IOU implement the reform in future DIDF cycles.

(end of Attachment A)

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Attachment B
IPE Scope of Work for DIDF Implementation

Term

- January 1st each year to July 31st the following year with the term subject to update by Energy Division if needed to support each DIDF cycle.

Pre-DPAG Period

- Develop an ***IPE Plan*** for each IOU describing the GNA/DDOR review process and detailed approach to Verification and Validation of all data used by the IOUs to prepare their DIDF filing materials.
    - Verification and Validation will include a thorough investigation of the following IOU processes, among others:
        - Collecting circuit loadings and performing weather adjustments;
        - Determining load and DER annual growth on the system level;
        - Disaggregating load and DER annual growth to the circuit level;
        - Checking sum of all disaggregated load and DERs against system-level values;
        - Adding incremental known loads to circuit level forecasts;
        - Developing load, DER, and net load profiles and determining net peak loads;
        - Adjusting for extreme weather;
        - Comparisons to equipment ratings to determine if ratings will be exceeded;
        - Incorporating load transfers, phase transfers, correcting data errors;
        - Compiling GNA tables showing need amount and timing; and
        - Following the IOU's planning standard and/or planning process.
    - GNA/DDOR report review will include an in-depth analysis of the following IOU steps, among others:
        - Developing recommended solutions (planned investments);
        - Implementing the IOU's planning standards and/or planning process;
        - Estimating capital costs for planned investments;

- Developing list of candidate deferral projects through application of screens (timing and technical);
- Developing operational requirements;
- Prioritization of candidate deferral projects into tiers;
- Calculating LNBA values; and
- Comparing prior-year forecast and actuals at circuit level for candidate deferral projects.

- Work directly with the IOUs and Energy Division to develop draft plans as needed. Development of the draft IPE Plans may include, among other activities:
  - Meeting with the IOUs and Energy Division to identify and understand each business process and tool used to complete their GNA/DDOR filings.
- Facilitate or participate in stakeholder workshops to receive feedback on the IPE Plans.
- Review and incorporate comments in the final IPE Plans.
- Submit final IPE Plans to Energy Division and the IOUs with recommendations for future improvements to the plans.
- Other technical support assignments as defined by Energy Division to ensure the IPE and Energy Division will receive from the IOUs the data and cooperation necessary to complete the required evaluation of the GNA/DDOR filings.

DPAG Period

- Participate in all workshops and meetings during the DPAG period. Prepare and deliver presentations or handouts as requested by Energy Division (*e.g.*, final IPE Plan presentations).
- Develop an ***IPE Preliminary Analysis of GNA/DDOR Data Adequacy*** for all three IOUs.
- Review any comments on the preliminary analysis that may be received and discuss the results with Energy Division.

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- Facilitate meetings with Energy Division and the IOUs to correct data inadequacies and prepare further documentation and provide technical support as needed.
- Fully implement each IPE Plan as defined in the final IPE Plans.
- Develop an ***IPE DPAG Report*** for each IOU presenting GNA/DDOR review findings and Verification & Validation outcomes.
- Submit the draft reports to Energy Division for review and (if necessary) to the IOUs to check for confidential information that may be included or to clarify specific details.
- Circulate the final IPE DPAG Reports to stakeholders (public and confidential versions).
- Other technical support assignments as defined by Energy Division to ensure the DPAG process is successfully completed.

Sample Size

- The scope of review conducted by the IPE for each IOU process may encompass the full set of circuits/projects or a subset/sample of circuits or projects. Where sampling is determined to be appropriate by the IPE in consultation with Energy Division, the size of the sample set for each case will be determined by the IPE based on the application of engineering judgement.

Post-DPAG Period

- Develop a single ***IPE Post-DPAG Report*** covering all three IOUs; comparing their current and prior filings; evaluating DIDF DER procurement, operational, cost, and contingency planning outcomes; reviewing IOU compliance; and making recommendations for process improvements and DIDF reform.
- Coordinate with and support the Independent Evaluator (IE) with IE activities and the development of IE reports as needed.
- Submit the draft report to Energy Division for review and (if necessary) to the IOUs to check for confidential information that may be included.

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Appendix B DPAG Survey and Comment Responses

PG&E solicited feedback from the DPAG during their DPAG meeting on September 22, 2022 and also solicited comments by email. There were a number of comments from the Energy Department and the Public Advocates Office directed to PG&E. The responses to these questions were posted by PG&E to the R.21-06-017 Service List on October 5, 2022 and discussed during their DPAG follow-on meeting on October 21, 2022

Appendix C Copy of the IPE Plan

Note: The 2022/2023 IPE Plan for PG&E is included in a separate file from the file containing this report.

Independent Professional Engineer Plan for Pacific Gas and Electric

Submitted to California Public Utility Commission

9/21/2022

Submitted by:
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Contents

1 Introduction and Background

This document is the draft version of the Independent Professional Engineer Plan for the 2022/2023 Distribution Investment Deferral Framework (DIDF) cycle for Pacific Gas and Electric. The requirements for the plan and oversight by the Energy Division are spelled out in a recent CPUC Ruling 14-08-013 (April 13, 2020) which is attached as Appendix A. The Ruling modified the Distribution Investment Deferral Framework (DIDF) process and previous rulings with respect to the Independent Professional Engineer (IPE) scope of work and provided the updated 2020-2021 DIDF cycle schedule. As of writing this draft report, the 2022/2023 cycle schedule has not been finalized.

As a result of stakeholder comments regarding improving the effectiveness of the IPE process, schedule and expected results, a number of modifications were made by the Ruling and implemented for the first time in the 2020-2021 DIDF cycle. These changes have been incorporated in the IPE Plans developed ever since. Some of these changes are highlighted below:

- The IPE review process now starts earlier to allow for more time for the IPE, utilities and the Energy Division to perform the necessary production of data in response to data requests, verify and validate the data, produce reports and address the confidentiality of data in the reports prior to the IPE Report deadline. The review process starts in the late-April timeframe.
- The IPE scope includes development of a draft IPE Plan for each utility by mid-May in each cycle. The plan goes through a stakeholder review cycle and will be issued in final form by the IPE in August.
- The scope of the IPE review was expanded to include several new business processes
- The scope of the review was expanded to include the new CPUC Standard Offer Contract (SOC) and Partnership Pilots (PP).
- The original schedule for IPE deliverables was established in the CPUC 2020 Rulings for the 2020/2021 cycle[1]:
  - Draft IPE Plan. Due May 13, 2020
  - Final IPE Plan. Due August 15, 2020.
  - IPE Preliminary Analysis of GNA/DDOR Data Adequacy for all three IOUs. Due September 5, 2020.

[1] Dates shown below were originally set forth per the 2020 Ruling. The CPUC plans to issue a ruling with dates for the 2022/2023 DIDF cycle in May. These updated dates will be included in the Final PG&E IPE Plan.

- IPE DPAG Report for each IOU presenting GNA/DDOR review findings and Verification & Validation outcomes. Due November 15, 2020.
- IPE Post DPAG Report covering all three IOUs, comparing their filings, reviewing compliance, and making recommendations for process improvements and DIDF reform. Due February 5, 2021.

- The May 2022 draft IPE Plan for 2022/2023 DIDF cycle will be distributed to stakeholders in May to facilitate stakeholder comments prior to finalizing the IPE Plan in August 2022.

2 Description of the Plan

2.1 Definitions Used in the Plan and Other Deliverables

To facilitate understanding of the IPE scope of work, the following definitions are included and will be used in the Plan and throughout all of the IPE work products and deliverables.

> Verification – Is a review performed by the IPE during which an independent check is performed to determine if the results produced were developed using data assumptions and business processes that were defined and described by the utility or are based upon standard industry approaches that do not have to be defined and described. In other words, "Did the IOU follow their own processes correctly as defined and described by the IOU?"
>
> Validation – Is a review performed by the IPE during which an independent assessment is performed of the appropriateness of the approach taken by the utility to perform a task from an engineering, economics and business perspective. In other words, "Are the processes implemented by the IOU the best way to identify all planned investments that could feasibly be deferred by DERs cost effectively? And to what extent were the IOU methodologies appropriate and effective?"

The IPE Plan covers the business processes that the IOUs use to identify which distribution or sub transmission projects are recommended to proceed to 1) an RFO, 2) Standard Offer Contract or 3) Partnership Pilot seeking DER bids to determine if there is a cost-effective non-wires alternative. One of the core purposes of the plan is to answer the question - Are the IOUs identifying every project that could feasibly and cost effectively be deferred by DERs?

The business processes in the Plan are organized generally in the order that they are performed. Starting with capturing the peak load values for each circuit for 2021, using the CEC IEPR forecasts to develop utility specific system level values which are then disaggregated to the circuit level adjusted for known loads then used to determine if there is an overload or other issue during the planning period (nominally 2022 through 2026). For circuits that have a need, a planned investment is selected, capital costs developed for that project and the planned investments are screened to develop a list of candidate deferral projects. These candidate deferral projects are then prioritized into tiers using several metrics with the projects in the first tier normally recommended for a DER RFO. Candidate deferral projects are also considered for SOC or PP pilot programs based upon the results of the prioritization process along with additional set of metrics for SOC and PP pilots.

As indicated earlier, in the 2021/2022 cycle two new pilot programs were initiated that are testing new mechanisms to procure DERs. They are called the Partnership Pilot and a Standard Offer Contract. These pilots impact other parts of the business processes covered in the IPE Plan.

3 IPE Plan

The heart of the IPE Plan is the material contained in Table 3-1 below. This table lists the business processes, roles of the utility and IPE, target timing and information requirements for each business process in the IPE scope. Listed below is a more detailed description of the contents of Table 3-1:

- IOU Business Process / IPE Review Step – This column includes a number for each business process included in the table. To make it easier for readers who will be looking at more than one utility IPE Plan, the process was started with the same numbering for all three utilities and that set of numbers was maintained as much as possible. In cases where additional steps needed to be added to accommodate a utilities specific unique process a letter was added to the previous number. For example, the step after Step 3 was added and was number Step 3a. For cases where steps are not needed, they will be spelled out in the table.
- Business Process / IPE Review Step Description – This column contains a general description of the business process being reviewed.
- Plan for 2022/23 DIDF Cycle – This column includes several types of information:
  - A brief description of what the review will include and whether it would include review of a subset of the total number of elements (i.e., circuits) or all elements and what is being examined.
  - Roles which include the role of the utility overall and the role of the IPE for both the verification and validation review. For both reviews, an indication is provided for what the IPE will be checking for or confirming in the review.
    Note that there are generally two approaches to performing a verification. The first is a demonstration wherein the utility develops the necessary spreadsheet or other mechanism to show how the business process developed the results of interest and the IPE performs a walk through to view the demonstration by the utility. The second approach is wherein the IPE develops a spreadsheet or other mechanism to calculate the results of interest using data provided by the utility and then compares the results to the numerical utilities results.
- Target Timing – This column includes a target timing for the reviews in the business process in this row or in the timing that data will be provided to the IPE.
- Data/Information Requirements – This column includes the data or information that the IPE needs to perform its review and in some cases the date the information is required.

Table 3-1 PG&E IPE Review for 2022/23 DIDF Cycle is shown starting on the following page.

Table 3-1: PG&E IPE Review for 2022/23 DIDF Cycle

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
PROCESSES TO DEVELOP STARTING POINT LOAD, SYSTEM LEVEL VALUES AND DISAGGREGATE TO CIRCUIT LEVEL				
1	Collect 2021 actual circuit loading and adjust for weather as needed	Perform Verification for at least 10 circuits mutually selected by PG&E and the IPE; Verify the following: • Collection and correction of peak load data for the circuits • Normalization of corrected peak load based on weather, water allocation or other factors • Development of 1-in-2 and 1-in-10 Baseline load profiles in LoadSEER. Roles: PG&E to provide a description and demonstration of the processes used for peak load collection, scrubbing, normalization and correction for extreme weather. PG&E to provide the information specified in the Data/Information Requirements column.	PG&E to provide the process description (specified in the data/information column) by June 15. PG&E to provide the data/information items (1) and (2) (specified in the data/information column) by June 15. PG&E to provide the data/information item (3) (specified in the data/information column) by June 15.	PG&E to provide the data/information requested below. IPE to provide the data/information provided in the last cycle for reference. **Process Description:** PG&E to provide a description of the following process. PG&E to indicate if any of these processes have changed since the last GNA-DDOR cycle. ▪ Collection and correction of peak load data for the circuits ▪ Normalization of corrected peak load based on

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		Verification: IPE to review the data/information and demonstrations provided by PG&E and verify that these results are carried forward in the planning process in subsequent V&V steps. Validation: IPE to review the business process for reasonableness and consistent with the objectives of the DIDF process.	PG&E to provide a demonstration (specified in the data/information column) by June 30.	weather, water allocation or other factors ▪ Development of 1-in-2 and 1-in-10 Baseline load profiles in LoadSEER. **Data/Information:** (1) Summary data for the 10 circuits as shown below. Feeders should consist of at least 4 feeders with temperature as a normalization/adjustment variable, at least 3 feeders whose load is impacted by water allocation and at least 3 feeders without a normalization/adjustment forecast variable. a. Peak data raw (MW and Time) b. Peak data scrubbed (MW and Time) c. Peak data 1 in 2 (MW and Time)

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
				d. Peak data 1 in 10 (MW and Time) e. Temperature or water allocation corresponding to a above f. Temperature or water allocation corresponding to b above g. Temperature or water allocation corresponding to c above h. Temperature or water allocation corresponding to d above h. Data associated with water allocation i. Any other data relative to load measurement adjustments (2) PG&E to provide the 576 hourly (P75 and P95) load profiles from LoadSEER for the selected circuits. (3) PG&E to provide a list of feeders or a breakdown of the

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
				percentage of feeders with loads that are temperature sensitive, water allocation sensitive and those with neither temperature nor water allocation sensitivity. **Demonstration:** PG&E to provide a demonstration of the processes used for peak load collection, scrubbing, normalization, correction for extreme weather, as well as the development of the 1-in-2 and 1-in-10 profiles in LoadSEER.
2	Determine load and DER annual growth on system level	Perform Verification and Validation of how system-level, annual load and DER growth forecasts are developed by PG&E using the CEC IEPR forecasts. Roles:	PG&E to provide the data/information (specified in the Data/Information Requirements column) by June 15.	PG&E to provide the data/information requested below. IPE to provide the data/information provided in the last cycle as a reference.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		PG&E to provide data and information on how the system-level annual load and DER growth forecasts are developed by PG&E using the CEC IEPR forecasts PG&E provides description of CEC forecast used (name of the forecasts used), the EXCEL spreadsheet used and a link to CEC table(s) used. PG&E provides description as to how known load values are developed and how that load is managed if it should exceed the CEC forecast in any given year. Verification: The IPE will verify the CEC forecasts are used as described by PG&E to calculate the load and DER forecast values at the system level for 10 years. IPE to review spreadsheet results and compare the result from its spreadsheet model to the results developed by PG&E.	PG&E to provide the process description (specified in the Data/Information Requirements column) by June 15.	PG&E to provide the following: **Data/Information:** • Name(s) of the CEC IEPR forecast files and links to those files. • Excel spreadsheet used to calculate the system-level load growth by customer class. • Excel files containing the zonal forecasts for EV, PV and ES. Excel file containing busbar forecasts for EE. • Known load additions including amount, circuit name, class, type of load and in-service date. **Process Description:** • PG&E to provide the description of the process

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IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		IPE to review the process used to PG&E to adjust the CEC system-level load forecasts for known load additions. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		used to develop system-level load growth (for customer classes) and DER growth from the CEC forecast. • PG&E to provide description as to how known loads are developed and how that load is modeled should it exceed the CEC forecast. • PG&E to indicate if any of these processes have changed since the last GNA-DDOR cycle
3	Disaggregate load and DER annual growth to the circuit level	Perform verification and validation for circuit-level load and DER disaggregation. Roles: PG&E to provide the inputs and outputs, as well as a general description of the processes used for disaggregating system-level load growth to circuit-level	PG&E to provide the data/information (specified in the Data/Information Requirements column) by June 30. PG&E to provide the process description	PG&E to provide the data/information requested below. IPE to provide the data/information provided in the last cycle for reference. **Data/Information:**

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		and further at a class level (Domestic, Commercial, Industrial) using LoadSEER. PG&E to provide the inputs and outputs, as well as a general description of the processes used for disaggregating system-level DER capacity to circuit-level capacity. Verification: IPE to verify that the load and DER growth values at the circuit level match with the 576-hourly profiles for specific circuits that are chosen in Step 6. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.	(specified in the Data/Information Requirements column) by June 30.	▪ PG&E to provide circuit-level load growth by year and by customer class (AGR, COM, DOM, IND). ▪ PG&E to provide circuit-level values by year for the following DERs: PV, ES, EE and EV (LDV). **Process Description:** ▪ General description of the process used for disaggregating system-level load to circuit-level loads and further at a class level (Domestic, Commercial, Industrial) using LoadSEER. ▪ General description of the process used for disaggregating system-level DER capacity to circuit-level capacity and the tools/techniques used.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
				PG&E to indicate if any of these processes have changed since the last GNA-DDOR cycle. ▪ 576 hourly load profile for selected circuits provided in Step 5.
3a	Check sum of all disaggregated load and DERs same as CEC IEPR System Level values	Perform Verification on this aggregation for all circuit values as well as cross check values used in other V&V checks. Roles: Information provided by PG&E in Step 3 will also be used in this step. Verification: IPE to verify that the sums of all load and DER growth forecasts at the circuit level match the starting point system values verified in Step 2.		Data needed for this step is provided in Step 3

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
4	Add Incremental known loads to circuit level forecasts (in CEC forecasts and others not in CEC forecast)	Perform verification of the known load additions at the circuit level. Roles: Information on circuit-level known loads is already obtained in Step 2. In this step, the IPE will verify that the 576 hourly load profiles for selected circuits match with the values provided in Step 2. Verification: IPE to verify that the circuit-level known load additions provided as a part of Step 2 match with the 576 hourly load profiles for specific circuits that are chosen in Step 6.		576 hourly loads for selected circuits profiles provided in Step 5.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
5	Convert peak growth to 576 profile as needed	Perform V&V for 10-15 circuits mutually selected by the IPE and PG&E. Roles: PG&E to provide 576- hourly profiles for selected circuits, as well as the typical load profiles used for new residential, commercial, industrial and agricultural loads, as well as the typical corporate load forecast profile. Verification: IPE to verify that the 576 hourly load profiles for new loads (DOM, COM, IND, AGR) and corporate load forecast match with those values determined in Step 3 and 4. Validation:	PG&E to provide the data requested (specified in the Data/Information Requirements column) by July 15.	PGE&E to provide the 576 hourly load profiles for selected circuits as shown below: a) One or more circuits that have sensitivity to temperature and one or more that have sensitivity to water allocation b) One or more circuits that have known load (Residential or Commercial) additions c) One or more circuits that have identified needs that are solved using load transfer d) One or more circuits that have identified needs that are solved using phase balance

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		e) One or more circuits that have identified needs that are solved with a planned project f) One or more circuits with needs that result in Candidate Deferral Opportunity (CDO) project g) One or more circuits with known DC Fast Charger (DCFC) loads
5a	Convert DER growth to 576 profile as needed	Perform V&V for 10-15 circuits mutually selected by the IPE and PG&E in Step 5. Roles: PG&E to provide 576- hourly profiles for selected circuits, as well as the typical hourly profiles for DERs (PV, ES, EE, and LDEV).	PG&E to provide the data requested (specified in the Data/Information Requirements column) by July 15.	**Data/Information:** PG&E to also prove the hourly load profiles of the DERs (PV, ES, EE, and LDEV) for selected circuits. **Process Description:**

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		Verification: IPE to verify that the 576 hourly load profiles for the DERs match with those values determined in Step 3. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		PG&E to provide information on how these typical profiles are developed.
6	Derive net load profile	Perform V&V for 10-15 circuits mutually selected by the IPE and PG&E in Step 5. Roles: No new data required from PG&E for this step. Verification: IPE to use the results of Steps 5 and 5a to calculate net load profile and compare with the profile provided by PG&E. Validation:		No additional data/information is required.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
7	Determine net peak load	Perform V&V for 10-15 circuits mutually selected by the IPE and PG&E in Step 5. Roles: PG&E to provide the calculated peak load forecast for the selected circuits for the peak load hour that was used in the GNA. Verification: IPE to verify the value for these circuits provided by PG&E against the value obtained for the peak day from the 576 hourly net load profile developed in Step 6. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.	PG&E to provide the data requested (specified in the Data/Information Requirements column) by July 15.	PG&E to provide the calculated peak load for the selected circuits used in the GNA.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
8	Adjust for "extreme weather" (1 in 10)	Performed as part of Step 1 (See Step 1 above)	Performed as part of Step 1 (See Step 1 above)	Provided in Step 1 (See Step 1 above)
PROCESSES TO DETERMINE CIRCUIT NEEDS AND DEVELOP GNA				
9	Initial comparison to station outlet ratings or other circuit limiting factor to determine if ratings exceeded	Perform V&V for 10-15 circuits mutually selected by the IPE and PG&E in Step 5. Roles: PG&E to provide station outlet, transformer or other circuit limiting ratings for the selected circuits if not included in the GNA/DDOR Report. Verification: IPE to compare the net peak load from Step 7 before any load transfers are simulated and compare it with the rating	Data will be obtained in mid-August after GNA/DDOR report is published. Date for verification and Validation	Station outlet or other circuit limiting factor will be obtained from GNA Appendices or provided by PG&E if not included in the GNA Appendices.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		to determine if there is an overload (and the overload value matches with the value calculated by PG&E). Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
10	Incorporate load transfers, correct data errors	Perform V&V for 5-10 circuits mutually selected by the IPE and PG&E. Roles: PG&E to demonstrate how it adjusts for load transfers. Demonstration will include the impact of transfers and the data is used to predict the impact of making the proposed changes. Verification: IPE to verify the process reflected in the PG&E demonstration is consistent with the PG&E description and the result are the same as used in subsequent steps in	PG&E to provide the information requested (specified in the Data/Information Requirements column) by mid-August.	**Process Description:** PG&E provides a description of the load transfer process and how it determines the impact on individual circuits involved. **Data/Information:** PG&E provides transfer information for each circuit involved. This includes the pre and post loading for the planning period for all circuits involved or impacted by the transfers.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		process of developing the needs reflected in the GNA. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
11	Final comparison to station outlet ratings or other circuit limiting factor to determine if ratings exceeded	Perform V&V for 10-20 circuits mutually selected by the IPE and PG&E. Roles: Information provided in Step 5 will be used for the verification of this step. Verification: IPE to compare the net peak load from Step 8 after any load transfers and compare it to station outlet ratings or other circuit limiting factor to determine if there is an overload (and if so that the overload matches with the value calculated by PG&E and included in the GNA).		Data already provided in Step 5.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
12	Compile GNA tables showing need amount and need timing, etc. (per IOU's documented planning standards and/or planning process)	Perform V&V on development of GNA table entries for select circuits also confirming that planning standard/process was followed. Roles: PG&E to provide confidential version of Planned Investment tables in Xcel format that can be filtered by the IPE. PG&E to provide list of planning standards/criteria that were used in the development of the GNA tables. Verification: IPE to review projects in the GNA report against planning standards/criteria. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.	PG&E to provide the planning standards, if different than provided in the 2021 cycle in mid-August. PG&E to provide the data/information requested (specified in the Data/Information Requirements column) by mid-August after GNA/DDOR report is completed.	**Data/Information:** Confidential GNA tables in Xcel format **Process Description:** Copies of planning standards/criteria if different than provided in the 2021 cycle.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
PROCESSES TO DEVELOP PLANNED INVESTMENTS AND COSTS				
13	Develop recommended solution and generate list of Planned Investments (follow the IOU's documented planning standards and/or planning process)	Perform V&V for three to four projects selected by the IPE confirming that planning standard/process was followed. Projects to cover a range of project types. Roles: PG&E to demonstrate/describe process used to determine recommended planned solution for a subset of projects. PG&E to demonstrate the application of the process in developing the planned investment for selected projects. Verification: IPE to verify the PG&E demonstration reflects the description of the process provided by PG&E. IPE to verify that results shown in the demonstration follow the described process are same as included in DDOR.	PG&E to provide the description of the process in early September. Demonstration to be completed by early September.	**Process Description:** Description of process used to develop proposed planned project to address identified need for distribution projects if not included in the GNA/DDOR report.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
14	Estimate capital cost for each Candidate Deferral Project	Perform Verification and Validation for subset of five Candidate Deferral Projects selected by the IPE working with PG&E. Roles: PG&E to provide information describing the processes used to develop the capital cost estimates included in the DDOR. PG&E to describe the Expected Accuracy Level (as defined by AACE or by another method that describes the expected accuracy range in terms of % lower and higher than the estimate) of the capital costs for the projects included in the DDOR. If the Expected Accuracy is different for different projects, PG&E to	PG&E to provide the information requested in early September.	Information describing the processes used to develop costs. Expected Accuracy associated with the process described. Support cost data for projects in DDOR.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		provide the accuracy range for each project.[1] PG&E to provide supporting cost information for a subset of projects. Verification: IPE to verify that the supporting information for the selected projects confirms the process that was used and that the cost data supplied supports the final cost estimate provided by PG&E and included in the DDOR. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		

PROCESSES TO DEVELOP CANDIDATE DEFFERAL LIST AND PRIORITIZE

[1] During the course of implementing the IPE Plan, the ED in coordination with the IPE will seek to understand the effort and cost associated with improving the accuracy of capital cost estimates (i.e., from a Class 4 estimate accuracy to a Class 3 estimate accuracy).

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
15	Development of Candidate Deferral Projects list through application of screens (timing and technical)	Perform Verification for all projects put through screens Roles: PG&E to provide confidential version of Planned Investment table in Excel format that can be filtered by the IPE. PG&E to describe the process it used to develop its Candidate Deferral Projects. Verification: IPE to use the Excel tables to develop a list of Candidate Deferral Projects following the process described by PG&E. IPE to verify its result (list of Candidate Deferral Projects) match the PG&E results included in the DDOR. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.	Post GNA/DDOR Report release – to be completed by early September	▪ Confidential version of Planned Investment table in Excel format that can be filtered by the IPE. ▪ Description of process used to develop Candidate Deferral Projects ▪ DPAG materials

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
16	Development of operational requirements (daily, monthly annually etc.)	Perform V&V for five projects mutually selected by the IPE and PG&E. Roles: PG&E to provide description and/or demonstration of how LoadSEER and other techniques are used to determine operational requirements. (Required load, months and hours needed, duration of call and number of calls per year). Verification: IPE to utilize description to confirm operational requirements for selected circuits are developed using the process described and that the values developed are the same as included in subsequent steps of the process (DDOR and DPAG) Validation:	PG&E to provide the requested information in early September	PG&E to provide description and/or demonstration of how operational requirements are established. Operational requirements are expected to be load, months and hours needed, duration of call and number of calls per year

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
17	Prioritization of candidate deferral projects into Tiers	Perform Verification on prioritization process for all candidate deferral projects including process to develop list of projects that PG&E recommends proceed to RFO, SOC or PP procurement Roles: PG&E to provide active version (not just values) of the Excel spreadsheet that calculates the metrics and their components used to rank the Candidate Deferral Projects overall and into tiers. Note, in the 2021/2022 cycle the IOUs have agreed to use a single standard methodology to prioritize/rank Candidate Deferral Projects and to place them in various tiers based upon the prioritization results. PG&E to provide active version of spreadsheet (if one is used) used to rank and select candidate deferral projects for	PG&E to provide the requested information in early September	Demonstrate active spreadsheet that calculates prioritization metrics, components and ranks projects on those results. To include spreadsheets for prioritization of CDOs and for ranking/selecting SOC and PP projects. Note PG&E is implementing a database structure for the GNA/DDOR reporting process this cycle. The exported data from this database will be provided and the calculations will be explained where needed. ▪ Description of the IOU standardized prioritization metrics, components and tier

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		procurement using the SOC or PP procurement programs Verification: IPE to verify that spreadsheet calculations are consistent with the description of the standard IOU prioritization/ranking and tier placement methodology and SOC and PP ranking/selection process. IPE to verify that Excel results match the recommended Candidate Deferral Projects overall rankings and placement into tiers and recommended for RFO, SCO or PP procurement included in the DDOR and presented at the DPAG meetings. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		ranking methodology and process and SOC and PP ranking selection process

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
18	Calculate LNBA ranges and values for all planned investments	Perform Verification for a subset (1-2) of candidate deferral projects selected by the IPE in consultation with PG&E. Roles: PG&E to provide an active spreadsheet (not just values) that calculates all LNBA range values that are included in the DDOR for all Candidate Deferral Projects. PG&E to provide an active spreadsheet that calculates all LNBA metrics used in the project prioritization process (if different than values in the spreadsheet previously listed. Verification: IPE to verify that LNBA values are developed using a methodology that is the same as the one described by PG&E. IPE to verify results are the same as those included in the DDOR and project ranking process. Validation:	PG&E to provide the requested information in early October	▪ Description of the process used to develop LNBA ranges and metric values. ▪ Demonstrate active spreadsheet that calculates prioritization metrics and components. Note: PG&E is implementing a database structure for the GNA/DDOR reporting process this year. The exported data from this database will be provided and the calculations will be explained where needed.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
19	Compare 2021 forecast and actuals at circuit level for selected number of distribution circuits	Perform comparison of forecasted and actual loads for a statistically meaningful number of distribution circuits to be selected by the IPE in conjunction with PG&E. As a reference, in the 2021 cycle, 10% of the circuits were examined Roles: PG&E to demonstrate comparison of 2020 actual loads (as recorded and as adjusted) against 2020 Plan Year's forecasted 2020 load values. Verification: IPE to review PG&E demonstrated process, values and compare differences. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.	PG&E to provide the requested information in early October	Forecasted data from 2021 DDOR and recorded data from the 2022 Distribution Planning Process

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		OTHER IPE WORK		
20	Review implementing of planning standard and/or planning process	No further review is planned for the 2022/2023 DIDF cycle		
21	Review list of internally approved capital projects	No further review is planned for the 2022/2023 DIDF cycle.		
22	Respond to and incorporate DPAG comments	Include in IPE DPAG Report.	Completed by IPE in Mid-November (date)	
23	Track solicitation results to inform next cycle	Part of IPE Post-DPAG Report follow-on activities in coordination with the IE.	Q3-2022	
24	Treating confidential material in the IPE report	Confidentiality – the following steps will be followed to ensure that the IPE Reports treat confidential material consistent with the rules and procedures of the CPUC:	Target Dates listed in third column are aligned with the 2021/2022 DIDF cycle schedule and will be	

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		a. Hold an early meeting with IOU (and potentially the ED) to discuss process and for PG&E to flag those items they intend to request Confidentiality treatment and on what basis. IPE may provide feedback to ED in lieu of having the ED attend the meeting with the IOU and IPE. Discussion to be held by September 15. b. IOU provides public version of any documents[2] for which they will seek confidential treatment prior to period IPE is wrapping up report. Date: October 22, 2022. At this point the IPE should have two sets of documents that were provided by PG&E - one that contains documents that can be included in the public version of the report (all confidential information will be redacted) and a second set that has confidential information that is	updated in the Final IPE Plan.	

[2] Documents refers to any document provided to the IPE by the IOU that was not included in the IOU's public version of the GNA/DDOR reports. These documents will be included as attachments to the body of the IPE report as required by a CPUC ruling.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		readable, but such information is highlighted to show that it is confidential. This second set would be included as part of the confidential version of the IPE Report. c. IPE provides the final two sets of documents to the IOU that will be included in the IPE Report for final IOU confidentiality review by October 26. d. IPE provides the confidential version of the body of the draft IPE Report to the IOU by October 29 (the body of the report to include all but the documents provided in previous item) for final IOU confidentiality review. e. IOU provides comments/markups of on documents after final confidentiality review by November 4 and comments/markups of draft IPE report by November 5.		

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		Markups of the body of the report will include marking up the confidential version highlighting what data is designated as confidential (data that was not previously designated as confidential). f. After review and signoff, the IPE produces final Confidential Report on CPUC schedule and provides to ED and IOU – November 11. Between November 5th and 11th, the IPE and IOU work together to produce the final public version of the body of the report to ensure all confidential information is properly redacted in the public version of the report. On November 11th the public version is also provided to the ED and IOU. g. IOU requests CPUC Confidential Treatment using standard procedures.		

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		h. IOU files Public IPE Report version on CPUC schedule – DIDF Advice Letters submitted – November 15, 2020 i. IOU files revised Public Report if CPUC rejects any requests for confidential treatment; otherwise, process is complete, and no further action is needed. In the 2021/2022 cycle the IPE Plan was revised to avoid the use of tables, plots, graphs or other data in the IPE DPAG Report that end up needing to be redacted to meet the IOU's requirements. This should help to reduce the amount of redaction in the Public version of the IPE DPAG Report and make it easier for stakeholders to understand it.		

Appendix A CPUC 4/13/20 Ruling Excerpts

Attachment A
Listing of Schedule and IPE-Specific Reforms for the 2020-2021 DIDF Cycle

1. IPE-specific reforms for the 2020-2021 DIDF Cycle are implemented within the IPE Scope of Work presented in Attachment B.

2. IOU contracts with the IPE for the full scope of work identified in Attachment B shall be executed by the IOUs to allow for IPE Plan development to begin as soon as possible, ideally on or before **April 17, 2020**.

3. The IOUs shall work with the IPE and Energy Division to develop IPE Plans specific to each IOU such that the IPE can submit the Draft IPE Plans to Energy Division for review on or before **May 15, 2020**.

4. The IPE scope of work may be modified by Energy Division as needed for the IPE to successfully complete each assignment. The IOUs will promptly submit a Tier 1 Advice Letter to notice changes in scope should a scope change differ significantly from the scope described in Attachment B. Minor changes should not necessitate an Advice Letter filing.

5. As required by Energy Division on an annual basis, Pre-DPAG and Post-DPAG activities may include workshops; new, re-opened, suspended, or modified working groups (e.g., Distribution Forecast Working Group); and IOU presentations and deliverables.

6. During the Post-DPAG period and in consultation with the IPE, Energy Division may identify exemplary GNA/DDOR documentation components, analytical approaches, or data strategies implemented by one or more IOUs and require that each IOU implement the reform in future DIDF cycles.

(end of Attachment A)

Attachment B
IPE Scope of Work for DIDF Implementation

Term

- January 1st each year to July 31st the following year with the term subject to update by Energy Division if needed to support each DIDF cycle.

Pre-DPAG Period

- Develop an ***IPE Plan*** for each IOU describing the GNA/DDOR review process and detailed approach to Verification and Validation of all data used by the IOUs to prepare their DIDF filing materials.
    - Verification and Validation will include a thorough investigation of the following IOU processes, among others:
        - Collecting circuit loadings and performing weather adjustments;
        - Determining load and DER annual growth on the system level;
        - Disaggregating load and DER annual growth to the circuit level;
        - Checking sum of all disaggregated load and DERs against system-level values;
        - Adding incremental known loads to circuit level forecasts;
        - Developing load, DER, and net load profiles and determining net peak loads;
        - Adjusting for extreme weather;
        - Comparisons to equipment ratings to determine if ratings will be exceeded;
        - Incorporating load transfers, phase transfers, correcting data errors;
        - Compiling GNA tables showing need amount and timing; and
        - Following the IOU's planning standard and/or planning process.
    - GNA/DDOR report review will include an in-depth analysis of the following IOU steps, among others:
        - Developing recommended solutions (planned investments);
        - Implementing the IOU's planning standards and/or planning process;
        - Estimating capital costs for planned investments;

R.14-08-013, A.15-07-005, *et al.* ALJ/RIM/nd3

    - Developing list of candidate deferral projects through application of screens (timing and technical);
    - Developing operational requirements;
    - Prioritization of candidate deferral projects into tiers;
    - Calculating LNBA values; and
    - Comparing prior-year forecast and actuals at circuit level for candidate deferral projects.

- Work directly with the IOUs and Energy Division to develop draft plans as needed. Development of the draft IPE Plans may include, among other activities:
    - Meeting with the IOUs and Energy Division to identify and understand each business process and tool used to complete their GNA/DDOR filings.
- Facilitate or participate in stakeholder workshops to receive feedback on the IPE Plans.
- Review and incorporate comments in the final IPE Plans.
- Submit final IPE Plans to Energy Division and the IOUs with recommendations for future improvements to the plans.
- Other technical support assignments as defined by Energy Division to ensure the IPE and Energy Division will receive from the IOUs the data and cooperation necessary to complete the required evaluation of the GNA/DDOR filings.

DPAG Period

- Participate in all workshops and meetings during the DPAG period. Prepare and deliver presentations or handouts as requested by Energy Division (*e.g.*, final IPE Plan presentations).
- Develop an ***IPE Preliminary Analysis of GNA/DDOR Data Adequacy*** for all three IOUs.
- Review any comments on the preliminary analysis that may be received and discuss the results with Energy Division.

- 2 -

- Facilitate meetings with Energy Division and the IOUs to correct data inadequacies and prepare further documentation and provide technical support as needed.
- Fully implement each IPE Plan as defined in the final IPE Plans.
- Develop an ***IPE DPAG Report*** for each IOU presenting GNA/DDOR review findings and Verification & Validation outcomes.
- Submit the draft reports to Energy Division for review and (if necessary) to the IOUs to check for confidential information that may be included or to clarify specific details.
- Circulate the final IPE DPAG Reports to stakeholders (public and confidential versions).
- Other technical support assignments as defined by Energy Division to ensure the DPAG process is successfully completed.

Sample Size

- The scope of review conducted by the IPE for each IOU process may encompass the full set of circuits/projects or a subset/sample of circuits or projects. Where sampling is determined to be appropriate by the IPE in consultation with Energy Division, the size of the sample set for each case will be determined by the IPE based on the application of engineering judgement.

Post-DPAG Period

- Develop a single ***IPE Post-DPAG Report*** covering all three IOUs; comparing their current and prior filings; evaluating DIDF DER procurement, operational, cost, and contingency planning outcomes; reviewing IOU compliance; and making recommendations for process improvements and DIDF reform.
- Coordinate with and support the Independent Evaluator (IE) with IE activities and the development of IE reports as needed.
- Submit the draft report to Energy Division for review and (if necessary) to the IOUs to check for confidential information that may be included.

- Submit the final report to Energy Division and prepare public versions as needed.
- Support Energy Division with their review of DIDF reform comments, including comments on any IPE tasks.
- Support Energy Division's review of RFO materials and RFO outcomes.
- Attend RFO and procurement meetings and provide technical support as requested by Energy Division.
- Coordinate with the Independent Evaluator to support their evaluation and provide technical support at the discretion of Energy Division.
- Other technical support assignments as defined by Energy Division to develop and evaluate potential DIDF reforms and track and evaluate deferral opportunities that may be subject to ongoing review in other proceedings (e.g., pursuant to General Order 131-D).

List of IPE DIDF Deliverables

1. ***IPE Plan*** for each IOU describing the GNA/DDOR review process and approach to Verification & Validation for the underlying data.
2. ***IPE Preliminary Analysis of GNA/DDOR Data Adequacy*** for all three IOUs.
3. ***IPE DPAG Report*** for each IOU presenting GNA/DDOR review findings and Verification & Validation outcomes.
4. ***IPE Post-DPAG Report*** covering all three IOUs, comparing their filings, reviewing compliance, and making recommendations for process improvements and DIDF reform.

(end of Attachment B)

Reimagining tomorrow with Nexant today

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Appendix D Documents Received

The IPE received many sets of data from PG&E during the review. Listed below are the public documents provided to the IPE during the course of the review. These actual documents are provided as separate documents from the body of this report due to their size. Please contain the IPE to obtain a copy of these documents.

D.1 List of Documents Provided

- PGE.1.1b 10 Proposed Feeders 2022 Rev1 (Public)
- PGE.1.1c Forecast Shape Export - ANITA 1101 - 2022-06-01 0914
- PGE.1.1c Forecast Shape Export - ATASCADERO 1101 - 2022-06-16 0817
- PGE.1.1c Forecast Shape Export - EDENVALE 2109 - 2022-06-01 0910
- PGE.1.1c Forecast Shape Export - FIGARDEN 2102 - 2022-06-01 0919
- PGE.1.1c Forecast Shape Export - LAKEWOOD 1104 - 2022-06-01 0915
- PGE.1.1c Forecast Shape Export - LLAGAS 2101 - 2022-06-01 0909
- PGE.1.1c Forecast Shape Export - MANTECA 1704 - 2022-06-16 0833
- PGE.1.1c Forecast Shape Export - MERIDIAN 1102 - 2022-06-01 0918
- PGE.1.1c Forecast Shape Export - NOTRE DAME 1104 - 2022-06-16 0835
- PGE.1.1c Forecast Shape Export - RINCON 1101 - 2022-06-01 0918
- PGE.1.1c Forecast Shape Export - VASONA 1102 - 2022-06-16 0803
- PGE.1.1c Forecast Shape Export - WOLFE 1114 - 2022-06-16 0755
- PGE.1.1c Forecast Shape Export - WYANDOTTE 1107 - 2022-06-01 0914
- PGE.1.1c Forecast Shape Export - YOSEMITE 0402 - 2022-06-01 0917
- PGE.2.2a CED 2020 Load Modifiers - Mid Baseline Mid AAEE with CAISO
- PGE.5.5a Forecast Shape Export - Energy Efficiency 1000kW P95
- PGE.5.5ac Forecast Shape Export - DESCHUTES 1104 - 2022-07-08 0742
- PGE.5.5ac Forecast Shape Export - OREGON TRAIL 1104 - 2022-07-08 0741
- PGE.5.5af Forecast Shape Export - CARLOTTA 1121 - 2022-05-25 1218
- PGE.5.5af Forecast Shape Export - CARLOTTA BANK 1 - 2022-05-25 1218
- PGE.5.5ag Forecast Shape Export - WILLOWS A 1101 - 2022-07-08 0807
- PGE.16.16a Carlotta Bank 1 DER service Req+ Load profile Public

Independent Professional Engineer SCE 2022 DPAG Report

PUBLIC VERSION

Submitted to California Public Utilities Commission Energy Division and SCE

Date: March 15, 2023

Statement of Confidentiality

The CPUC made provision for the Investor-Owned Utilities to request confidentiality treatment for certain data submitted in their GNA/DDOR reports and other material provided to the IPE that is contained in this report. SCE has designated certain data in this report to be confidential. Thus, this PUBLIC VERSION of the report has certain data redacted in black. The data that is redacted in this report is confidential as a result of the application of the 15/15 rule.

In summary, this PUBLIC VERSION of the report can be distributed to any interested party since it does not include any confidential information.

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Contents

1. Introduction and Background

Summary of CPUC April 13, 2020 Rulemaking 14-08-013 and Other Rulemakings

The paragraphs that follow summarize the parts of the April 13, 2020 CPUC ruling and other rulings that directly impact the role of the Independent Professional Engineer (IPE) and/or this report.

The April 13, 2020 CPUC Ruling modified the Distribution Investment Deferral Framework (DIDF) process and filings with respect to the IPE scope of work and provided the updated 2020-2021 DIDF cycle schedule. Attachments A and B of the Ruling include a listing of the IPE-specific reforms discussed in the Ruling and the updated IPE scope of work. These Attachments of the Ruling are attached as Appendices A of this report.

In Decision 18-02-004, the Commission adopted the DIDF. Building upon the Competitive Solicitation Framework developed in the companion Integrated Distributed Energy Resources (IDER) proceeding, the DIDF established an ongoing annual process to identify, review, and select opportunities for third party-owned distributed energy resources (DERs) to defer or avoid traditional capital investments by the investor-owned utilities (IOUs) on their electric distribution systems. Decision 18-02-004 ordered the IOUs to implement the DIDF that would result in the selection of distribution upgrades for deferral through the competitive solicitation of DERs.

The DIDF was implemented in 2018 and 2019 with the expectation that it would be evaluated and revised after each cycle to improve the process. To that end, the assigned Administrative Law Judge (ALJ) issued a Ruling Requesting Answers to Questions to Improve the Distribution Investment Deferral Framework Process on February 25, 2019 (February 25, 2019 Ruling). Based on these comments, the ALJ issued a Ruling Modifying the Distribution Investment Deferral Framework Process on May 7, 2019 (May 7, 2019 Ruling). The parties have proposed additional recommendations for DIDF reform throughout the 2019 DIDF cycle. A Ruling Requesting Comments on Possible Improvements to the 2020 Distribution Investment Deferral Framework Process was subsequently issued on November 8, 2019 (November 8, 2019 Ruling), and the contents of this Ruling further modify the DIDF. A Ruling on May 11, 2020 modified the DIDF filing and process requirements including proposing a number of possible reforms to the DIDF followed by a ruling in June 2021 establishing new reforms and modifying some of those included in the May 11, 2020 ruling.

The CPUC issued Ruling 14-10-003 on 2/12/21 titled Decision Adopting Pilots to Test Two Frameworks for Procuring Distributed Energy Resources that Avoid or Defer Utility Capital Investments. In that ruling the CPUC added two additional procurement mechanisms to the DIDF cycle and spelled out how pilots of these two mechanisms are to be implemented over the next few DIDF cycles. The two new mechanisms are called the Standard Offer Contract (SOC), which applies to in front of the meter DERs, and the Partnership Pilot (PP), which applies to behind the meter DERs. The ruling also includes some revisions to the DIDF process and timing which are followed in this cycle's IPE review and this report.

The IPE scope of work outlined in Attachment A provides for improvement to the IPE review process based on comments received and clarifies that the development of IPE review plans for each IOU will be overseen and approved by Energy Division. According to the Ruling, it is important the IPE has sufficient time to prepare the IPE Plans in advance of the Grid Needs Assessment (GNA)/ Distribution Deferral Opportunity Report (DDOR) filings and that after the filings, the IPE has the cooperation and coordination of the IOUs necessary to collect the data needed for review in time to prepare the IPE Preliminary Analysis of GNA/DDOR Data Adequacy and IPE DPAG Report.

The revised IPE scope reflected in Ruling 14-08-013 includes the requirement to develop an IPE Plan that will cover most if not all of the IPE activities. A copy of the Final 2022 IPE Plan for Southern California Edison (SCE) is included in Appendix C. Note that this plan was developed prior to SCE deciding to make a partial DDOR filing on September 2, 2022.

According to the Ruling, planning standards that lead to the identification of reliability needs need not be reviewed at this time. Instead, the IOUs should provide the IPE with planning documentation that supports the identification of all reliability needs. At this time, a formal review of IOU planning standards is not required as it could be a significant undertaking. However, the Ruling states that the Energy Division should discuss the 2022 GNA/DDOR filings with the IPE to determine if inconsistencies and shortcomings in the IOU planning standards exist and whether further review should be prioritized for future DIDF cycles.

The April 13, 2020 CPUC Ruling goes on to state to further assist the IPE with DPAG Report completion, a new IPE Post-DPAG Report deliverable is included within the IPE scope of work. The IPE Post-DPAG Report should review and compare overall IOU DIDF compliance and make recommendations for process improvements and DIDF reform.

As stated in the May 7, 2019 Ruling, the IPE shall report directly to Energy Division to prepare its deliverables and conduct its analyses for DIDF implementation. The April 13, 2020 Ruling states the term of the IPE scope of work shall be the entire DIDF cycle, which starts on January 1 each year to plan for Pre-DPAG and DPAG implementation and concludes on July 31 the following year after all RFOs are concluded and all DIDF reforms are implemented. As a result, IPE scopes of work for each DIDF cycle will overlap.

The schedule and milestones established by the April 13, 2020 Ruling and as modified in subsequent rulings are shown below as they apply to the 2022/2023 DIDF cycle and IPE activities

Table 1-1: DPAG Schedule for 2021-2022 DIDF Cycle

Activity	Date
Pre-DPAG	
Pre-DPAG meetings and workshops, including Draft IPE Plans review	May 2022
DPAG	
IOU GNA/DDOR filings, Final IPE Plans circulated/; SCE revised date	August 15, 2022/Sept 2, 2022
IPE Preliminary Analysis of GNA/DDOR data adequacy circulated	September 5, 2022
DPAG meetings with each IOU	September 15, 2022 (week of)
Participants provide questions and comments to IOUs and IPE	September 25, 2022
IOU responses to questions	October 5, 2022
Follow-up IOU meetings via webinar	October 10, 2022 (week of)
IPE Initial DPAG Reports (Based upon Sept 2 Abbreviated DDOR Filing	Prior to November 15, 2021
DIDF Advice Letters submitted	November 15, 2021
SCE GNA/DDOR Filing (Complete)	January 13, 2023
Final SCE DPAG Report	March 15, 2023

Independent Professional Engineer

The California Public Utilities Commission (Commission) rulings direct Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities or IOUs) to enter into a contract with an IPE. The role of the IPE is as previously described.

Through a contract with Nexant, Inc. (now a part of Resource Innovations), SCE engaged Mr. Barney Speckman[1], PE, to serve as the advisory engineer (referred to as the IPE) for the scope described in the April 23, 2020 CPUC Ruling are as modified by subsequent rulings.

1.1. IPE Plan

As required by the April 23, 2020 Ruling, the IPE developed an IPE Plan that served to guide the IPE's steps to implement its 2020 DIDF work scope. The plan was developed using a three-step process:

1. In step 1 the IPE developed a draft IPE Plan working with the Energy Division and SCE by mid-May 2022.
2. The Plan was distributed to the service list and also discussed at the CPUC Distribution Forecasting Working Group meeting - both in an attempt to obtain stakeholder feedback on the plan.
3. Based upon stakeholder feedback received and under the direction of the Energy Division, the IPE revised the plan and made its IPE Final Plan available on August 25, 2022. Note since SCE decided to file a partial DDOR on Sept 2, 2022 and the full GNA/DDOR by January 13, 2023, the IPE Plan was not revised and distributed by August 25, 2022 but will be revised and distributed with this final IPE SCE DPAG Report,

A copy of the Final IPE Plan is included as Appendix C.

The IPE Plan covers the business processes that SCE uses to identify which distribution or subtransmission projects are recommended to proceed to an RFO seeking DER bids to determine if there is a cost-effective non-wires alternative. One of the core purposes of the plan is answer the question - Are the IOUs identifying every project that could feasibly and cost effectively be deferred by DERs?

The business processes in the Plan are organized generally in the order that they are performed. Starting with capturing the peak load values for each circuit for 2021, using the California Energy Commission (CEC) Integrated Energy Policy Report (IEPR) forecasts to develop utility specific system level values which are then disaggregated to the circuit level adjusted for known loads and then used to determine if there is an overload or other issue during the planning period. For circuits that have a need, a planned project is selected to address one or more needs, capital costs developed for that project, and the planned projects/investments are screened to develop a list of potential candidate deferral projects. These candidate deferral projects are then prioritized into tiers using several metrics, with the projects in the first tier normally recommended for a DER RFO. In this cycle, projects were also selected from the candidate deferral list to participate in the two CPUC Pilots – the SOC and PP.

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[1]Consistent with the CPUC decision, the contract with Nexant Inc. the firm where Mr. Speckman is employed provides for other individuals within Nexant to assist Mr. Speckman to perform the work in the IPE contract provided that these other individuals are also bound by the same confidentiality and conflict of interest requirements that Mr. Speckman is required to meet.

1.2. Definitions of Verification and Validation

As part of the development of the IPE Plan, detailed definitions were developed to clarify the meaning of Verification and Validation as applied to the IPE scope of work. These definitions which are used and applied in all IPE deliverables, are listed below:

Verification – Is a review performed by the IPE during which an independent check is performed to determine if the results produced were developed using data assumptions and business processes that were defined and described by the utility or are based upon standard industry approaches that do not have to be defined and described. In other words, "Did the IOU follow their own processes correctly as defined by the IOU?"

Validation – Is a review performed by the IPE during which an independent assessment is performed of the appropriateness of the approach taken by the utility to perform a task from an engineering, economics and business perspective. In other words, "Are the processes implemented by the IOU the best way to identify all planned investments that could feasibly be deferred by DERs cost effectively? And to what extent were the IOU methodologies appropriate and effective?"

1.3. Services Considered within the GNA/DDOR Framework

The CPUC, in a previous decision[2], approved the four services proposed by the Competitive Solicitation Framework Working Group (CSFWG) and directed the utilities to consider these services in the GNA/DDOR process. The four services as described in the decision are listed below in an excerpt from the decision:

> "The following definitions for the key distribution services that distributed energy resources can provide are adopted for the Competitive Solicitation Framework:
>
> Distribution Capacity services are load-modifying or supply services that distributed energy resources provide via the dispatch of power output for generators or reduction in load that is capable of reliably and consistently reducing net loading on desired distribution infrastructure;
>
> Voltage Support services are substation and/or feeder level dynamic voltage management services provided by an individual resource and/or aggregated resources capable of dynamically correcting excursions outside voltage limits as well as supporting conservation voltage reduction strategies in coordination with utility voltage/reactive power control systems;
>
> Reliability (back-tie) services are load-modifying or supply service capable of improving local distribution reliability and/or resiliency. Specifically, this service provides a fast reconnection

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[2]Decision 16-12-036; definitions can be found on Page 8. Link to document below:
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M171/K555/171555623.PDF

and availability of excess reserves to reduce demand when restoring customers during abnormal configurations; and

Resiliency (micro-grid) services are load-modifying or supply services capable of improving local distribution reliability and/or resiliency. This service provides a fast reconnection and availability of excess reserves to reduce demand when restoring customers during abnormal configurations."

1.4. Approach to Information Collection

The information reflected in this report was obtained through a number of methods including:

- Participation by the IPE in the CPUC sponsored 2022 Distribution Forecasting Working Group held on May 16, 2022.
- Special conference calls with SCE were held to perform Verification and/or Validation Demonstration walk-throughs as described in the IPE Plan and whose results are described later in the report. These walk-throughs were held prior to and after SCE's January 13, 2023 GNA/DDOR filing as follows:
  - July 7 – Steps 2, 3, 3a, 1 and 8
  - July 14 – Step 1, 8, 4, 5, 6, 7
  - November 4 – Steps 14-18
  - December 14 - Refresh of Steps 1-8 (reviewing revised data that will be filed on January 13, 2023)
  - February 10, 2023 – Step 9-12 Update
  - February 15, 2023 – Step 19
  - February 21, 2023 – Steps 14-18 Update
  - February 21, 2023 – Step 13 Update
- Written data requests sent to SCE regarding data or their planning process that led to the needs identified in their GNA Report and the projects included in their DDOR Report. Responses from SCE were made during follow up conference calls or in writing.
- Participation in SCE's DPAG meeting (September 23) and its follow up DPAG Webinar (October 20).
- A review of publicly available materials referred to in the discussions with SCE or materials previously filed with the CPUC.

1.5. Report Contents

The remainder of this report includes the following sections:

- Section 2 – Review of GNA Report which briefly discusses the contents of the SCE GNA Report and the difference between SCE and other IOUs because of its Subtransmission System and any significant differences noted in SCE's reports between the 2022 and 2021 DIDF cycle. Observations, comments, and recommendations that result from the Validation review with respect to the GNA Report are included in this section.

- Section 3 – Review of DDOR Report which briefly discusses the contents of the SCE DDOR Report and any significant differences noted, if any, in SCE's reports between the 2022 and 2021 DIDF cycle. Observations, comments, and recommendations that result from the Validation review with respect to the DDOR Report are included in this section.
- Section 4 – Review of Screening and Prioritization which discusses the screening and prioritization process and results. In this cycle, the three utilities used for the second time a jointly developed prioritization workbook for prioritizing projects. Observations, comments, and recommendations that result from the Validation review with respect to the screening and prioritization are included in this section.
- Section 5 – Review of Candidate Deferral Projects which includes the review of projects that have been placed into the Tiers defined by SCE. This section also includes the review of projects selected for the SOC and PP pilots. Observations, comments, and recommendations that result from the Validation review with respect to the placement of projects in the SCE defined Tiers and the selection of projects for the two pilots are included in this section.
- Section 6 – Discussion of Other Topics of Interest. Observations, comments, and recommendations that result from the Validation review with respect to these topics are included in this section.
- Section 7 – Verification completed which reviews the approach and results of the verification performed by the IPE.
- Appendix A – IPE Scope - Excerpt from April 23, 2020 CPUC Rulemaking 14-08-013.
- Appendix C – IPE Final IPE Plan - SCE
- Appendix D – Documents Received

Identifying Confidential Information

There are a number of places in this report that may contain confidential Information. They may include, for example, grid needs information from the GNA or DDOR that are subject to the 15/15 Rule. This data, if any, is highlighted (with a dark grey background) to show that it is Confidential but is still readable in this Confidential version of the report. In the Public version of the report this data is redacted.

These data elements which are considered confidential by SCE because they are entries for circuits/substations that meet the 15/15 Rule.

As noted earlier, there is no confidential information included in this report.

2. Review of GNA Report

The GNA Report submitted by SCE on January 13, 2023 is summarized at a high level in this section.

2.1. Scope of SCE's GNA/DDOR Reports

Unlike the other two IOUs, most of SCE's subtransmission system is under CPUC jurisdiction. The SCE subtransmission system is not planned for like most utilities subtransmission systems in that they are radial networks served by a single interconnection point from the CAISO-controlled Bulk Electric System. SCE's subtransmission system does not have multiple parallel paths for power to flow from one subtransmission system to another. SCE's subtransmission systems are contained as single networks that have parallel power flow paths from a subtransmission substation to a network of distribution substations. As a result, the majority of SCE's subtransmission systems are not subject to the CAISO Transmission Planning Process (TPP) and are planned for by SCE per SCE's planning criteria, and thus are included in the GNA/DDOR process.

Below is a discussion of some of the differences between Subtransmission vs. Distribution as it relates to the GNA/DDOR process:

- SCE's distribution system and most of its subtransmission systems are under the CPUC's jurisdiction.
- Distribution facilities serve a much smaller set of customers compared to the subtransmission system, which serves multiple distribution facilities. Loads on the subtransmission can be as large as a 1,000 MW.
- SCE's subtransmission system has a higher standard of reliability requirement compared to the distribution system due to the number of customers that could be impacted as a result of an outage.
- The subtransmission system is planned such that it can serve all customers during a single contingency outage condition while the distribution system is planned to serve customers when all equipment is in service. Distribution equipment outages may result in customer outages until reconfiguration of the distribution is accomplished (if feasible) or until equipment out of service is repaired and returned to service.
- Many SCE subtransmission projects in the DDOR are driven by the outage condition known as N-1 (loss of one subtransmission element).
- Such projects may be driven by capacity deficiencies and/or voltage issues that exist after a piece of equipment experiences an unplanned outage (N-1 condition).
- To avoid operating in an unreliable condition if an N-1 event occurs, certain equipment may be activated/dispatched with what is known as a pre-mitigation measure to prevent problems from occurring during an N-1 contingency condition should it occur.
- Such a pre-mitigation action might be to switch subtransmission capacitors into service to prevent low voltages if a certain N-1 is anticipated to cause an unacceptable low voltage condition.

- As a result of SCE's subtransmission system topology and the fact that it is not subject to the CAISO TPP, the projects listed in SCE's DDOR due to SCE's subtransmission system are much more varied than the projects listed in the other two IOU's DDORs.

2.2. Summary of SCE's 2022 GNA Report

SCE's GNA Report is a written report narrative along with an Excel data base of potential grid needs on its distribution and subtransmission system under CPUC jurisdiction. SCE filed its final GNA and DDOR Report on January 13, 2023 as approved by the CPUC. In this report we only touch upon a few highlights of the report and spreadsheet in the GNA Report and recommend to those who are interested in more details to review the GNA Report narrative and associated spreadsheets.

The GNA covers needs for all distribution circuits and substations and subtransmission lines and substations under the jurisdiction of the CPUC. The SCE GNA spreadsheet included 321 separate entries. For comparison, there were 262 needs in the 2020 cycle and 276 in the 2021 DIDF cycle spreadsheet

SCE provided a number of tables that summarize its GNA data. These tables were provided in a form that addresses a number of the reforms included in the 2020 May CPUC Ruling. For easy reference a few of these tables are duplicated here.

Table 2-1: GNA Needs by Asset Type

Asset Type	Capacity	Capacity (UCT)	Reactive Power	Reliability, Capacity	Reliability, Voltage	Voltage	Total
Distribution Feeder	62	153	35	6	0	9	265
Distribution Substation	24	0	0	2	5	1	32
Subtrans, Substation	1	0	2	5	0	0	8
Subtransmission Line	3	0	0	13	0	0	16
Total	90	153	37	26	5	10	321

Table 2-2: Summary of Grid Needs by Distribution Service Type and Region

Region	Capacity	Capacity (UCT)	Reactive Power	Reliability, Capacity	Reliability, Voltage	Voltage	Total
Desert Region	13	22	8	4	2	2	**51**
Metro East Region	13	42	11	3	0	0	**69**
Metro West Region	24	10	4	2	0	0	**40**
North Coast Region	13	24	5	10	1	0	**53**
Orange Region	1	16	6	3	0	0	**26**
Rurals Region	18	8	1	2	0	8	**37**
San Jacinto Valley Region	8	26	2	0	0	0	**36**
San Joaquin Region	0	5	0	2	2	0	**9**
Total	90	153	37	26	5	10	321

From the data we can see the following:

- There was a total of 321 needs identified in the distribution and subtransmission planning process. This compares to 276 needs in the last cycle.
- 93% (297) of the needs identified were for Distribution assets including 83% (265) as Distribution Circuits and 10% (32) Distribution Substations and substations. The corresponding figures for the last cycle were 90% (249) of the needs were for Distribution assets with 83% (229) as Distribution Circuits and 7% (20)) Distribution Substations, showing a slight trend of more distribution assets with needs than subtransmission.
- Roughly 8% (24) were Subtransmission related needs – including both circuits and substations compared to roughly 10% in the last cycle.
- 90% (290) of the needs identified are within the first three years of the planning period and will be potentially screened out in the timing screen process. These same figures for the last cycle were 91% (252).

- GNA Needs for this cycle by year are 217 needs (2022), (55) 2023, 18 (2024), 14 (2025) and 17 (2026). From this data we see that 90% of the needs occur in the first three years and as such are screened out of consideration as a candidate deferral opportunity project by the timing screen.

The GNA Report also includes a detailed description of SCE's planning process which includes detailed description and in some cases examples of 1) developing the starting point for load forecasts, 2) develop SCE system level load and DER growth using CEC IEPR data, 3) disaggregation of system level data, 4) processing of embedded and incremental load growth projects, 5) development of load and DER profiles, 6) determining if any assets will be overloaded based upon these forecasts, 7) determine if there is a no cost solution to mitigate the overload, and 8) if not develop a project that will resolve the overload. These and other steps are covered in Section 7 – Verification.

Microgrid Projects

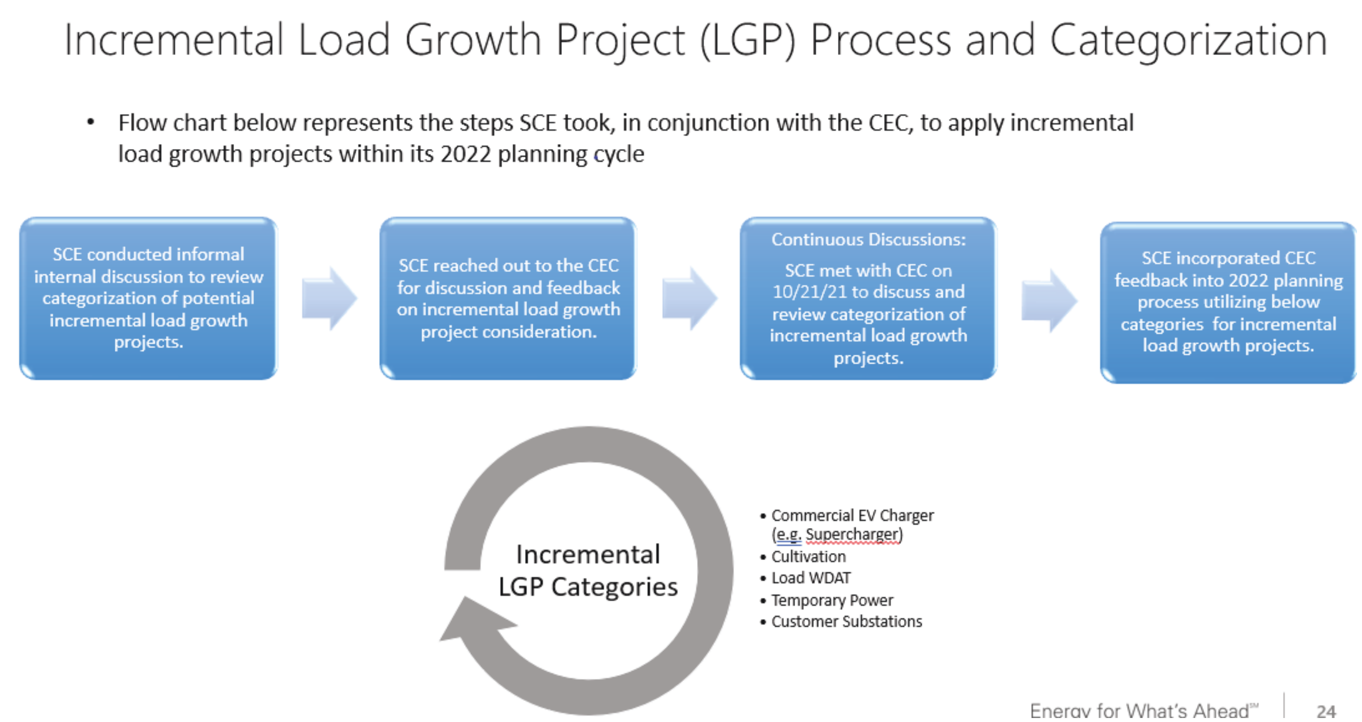
SCE indicated that they do not currently develop projects that utilize local generation to serve customers over utility distribution lines in a Microgrid configuration within its annual planning processes and therefore, there are no Resiliency services needs (sometimes referred to as Microgrid services) included in SCE's 2022 GNA.

Incremental Load Growth Projects

SCE utilized incremental known load growth projects in the 2022 DIDF cycle as it has done in the recent past to develop its forecasts at the circuit level which are used to determine needs. These local known loads, which are included in their forecasts (referred to as Incremental Load Growth Projects [LGPs] in their report), represent local loads that are in addition to the provisions for such known loads that are already assumed to be included in the CEC IEPR forecasts for SCE. The later local known loads which are considered by SCE as part of the IEPR are referred to as embedded load growth project by SCE.

Figure 2-1 below (developed by SCE) summarizes what SCE has done to work with the CEC to work toward including all local known loads in the CEC IEPR which would eliminate the need for SCE to utilize incremental known loads.

Figure 2-1: SCE Steps Regarding Incremental Loads



These additional local known loads are based upon input from SCE planning engineers who are familiar with the plans for new customers in their planning areas and are determined to be incremental to the CEC IEPR by SCE. As we will see in the discussion below, these incremental loads fall into five categories in the 2022 DIDF cycle – EV supercharging stations, cultivation operations, Load WDAT[3], and Temporary Power[4] and Customer Substations.

Table 2-3 shows how the type of known loads that have been treated by SCE as incremental have changed over time. From the table we see that the same five types of loads have been used in 2022 and 2021 DIDF cycles. Note that the legal requirement for using the IEPR as a starting point for distribution planning first occurred in 2017 but was not incorporated until 2018.

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[3] Load Wholesale Distribution Access Tariff. Power purchased by a customer from generation sources on the (Independent System Operator) ISO grid and power transported from ISO grid to the customer using the Distribution Provider's electrical system.

[4] A utility-connected source of power that is fed to a job site to serve the load of the equipment used in the construction of a structure. The temporary power is removed from service when the construction is complete, and the newly constructed building is fed from its permanent power supply.

Table 2-3: Incremental Projects Over the Years

Incremental Projects Over the Years

	2017	2018	2019	2020	2021	2022
No Limits and no incorporation of IEPR*	X					
Cultivation		X	X	X	X	X
Commercial EV Superchargers			X	X	X	X
Temporary Power		X		X	X	X
Load WDAT				X	X	X
Customer Subs for Transmission Substation Planning					X	X
Data Centers, Facility Expansion and Spec Buildings >=2.5 MVA		X				
Agricultural Pump Load		X	X			
Mega Tract Homes		X	X			
Reservation and Government funded projects		X				

*IEPR legal requirement occurred in 2017 but was not incorporated until 2018

As a result, the inclusion of these incremental local known loads will result in the aggregate load being served to all customers modeled in the Transmission and Distribution (T&D) planning process being larger than the CEC IEPR load forecast for SCE by the amount of the total of these incremental local known loads.

Statistics regarding these incremental loads are shown in the two graphs below. The total MW impact of incremental growth ranges from the addition of about 420 MW in 2022, 210 MW in 2023, and 105 MW in 2024, 70 MW in both 2025 and 2026 and drops off dramatically in 2027 and remains low for the rest of the 10-year forecast period. As a comparison, the values in the last cycle (2021 DIDF cycle) ranged from 450 MW in 2021, 200 MW in 2022, and 105 MW in 2023, to an average of less than 25 MW for years beyond 2023. This represents a small reduction in incremental known loads in the 2022 cycle values in all years compared to the 2021 cycle. The maximum addition in the 2019 (two cycles ago) was about 225 MW which was also predominantly due to cultivation thus showing an increasing trend over time.

We can see the predominant LGP continues to be incremental growth attributed to cultivation load with commercial EV chargers second. In Figure 2-2 we see that the load on 279 circuits (down from 374 in the previous cycle) are impacted by these five categories of LGPs with 70 or 25% being cultivation loads (down from 50% in the last cycle). Overall, cultivation projects have the dominant MW impact and most of that occurs in the first five years of the planning period (2022-2026). Transportation electrification is the second largest type of known loads which shows a growth from 152 circuits impacted in 2021 to 201 circuits in 2022 and 179 individual loads in 2021 to 223 individual loads in 2022 representing an annual increase of 32% and 25% respectively. Overall, in this cycle the MWh of incremental known load growth added over the first five years of the planning period is approximately the same MWh load growth that is included in the IEPR load growth forecasts before the addition of the incremental load growth. In other words, the net effect of including incremental load growth is to double the load IEPR growth in the first five years, before considering and DER impacts.

Figure 2-2: Incremental LGP by Category

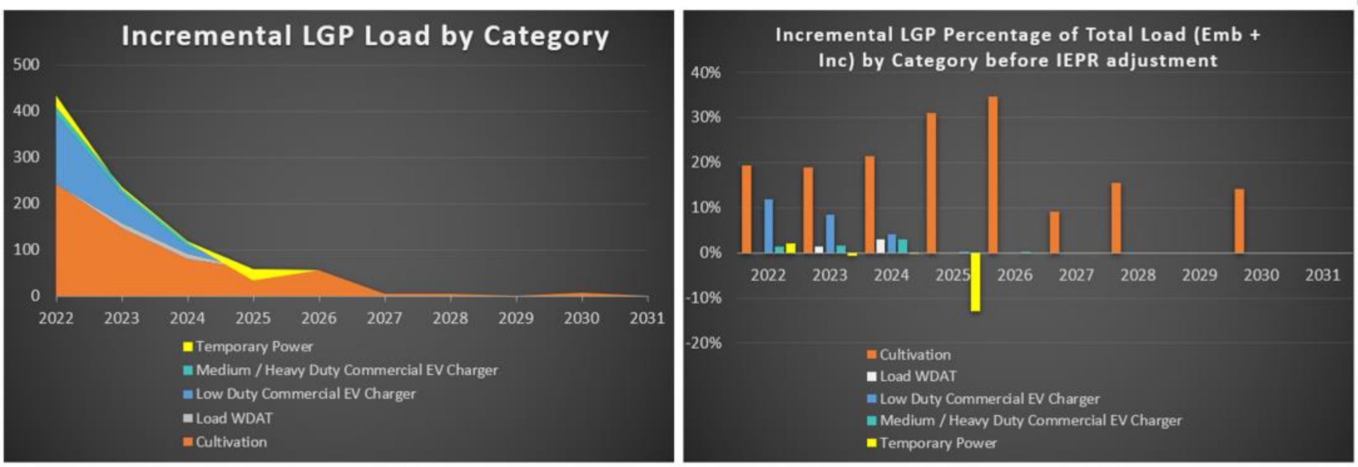
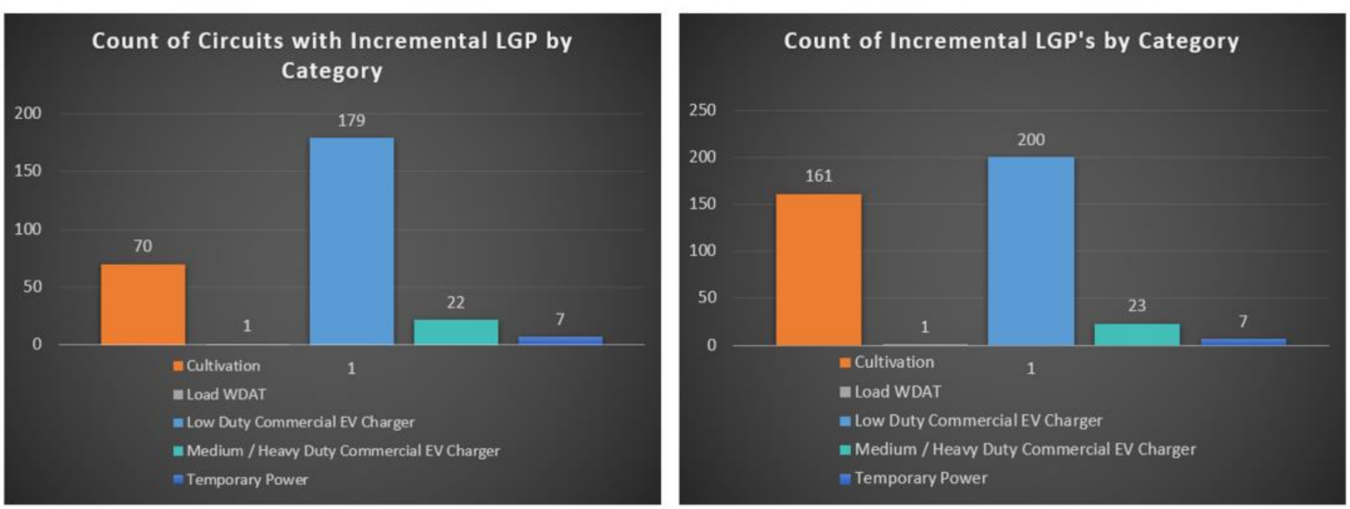


Figure 2-3: Number of Circuits and Projects with LGPs by Category



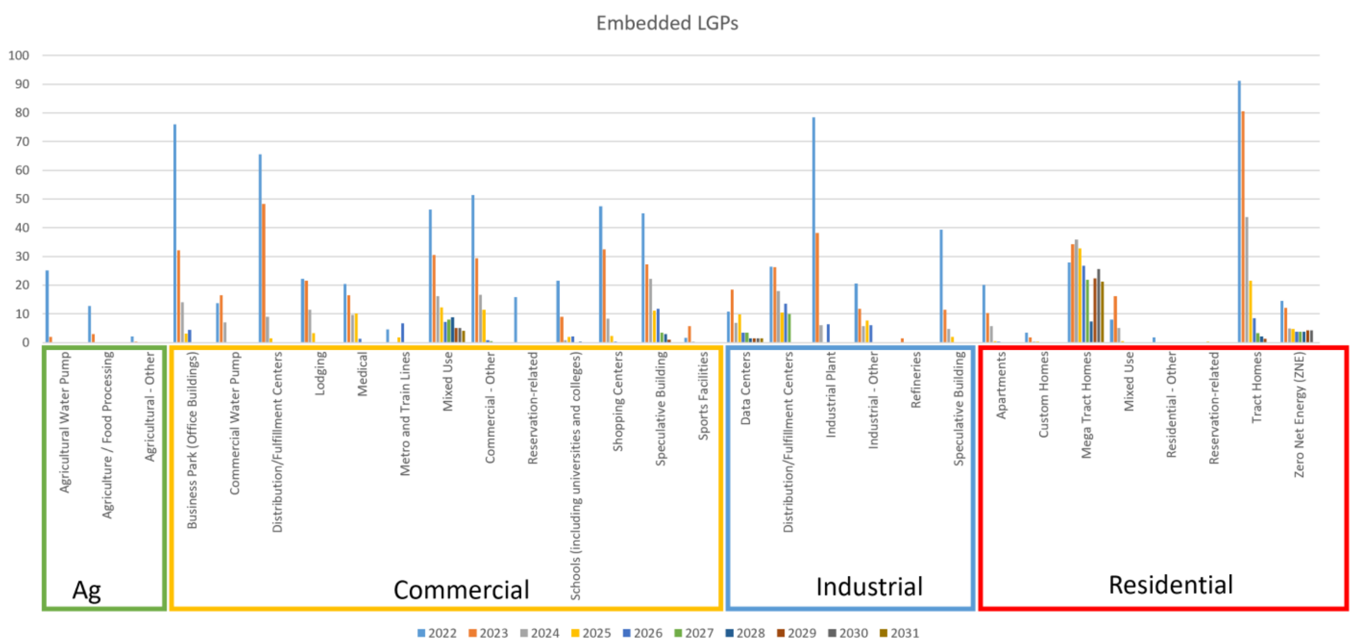
Embedded Load Growth Projects

As part of the IPE review, SCE's load growth projects that were assumed to be included the CEC IEPR forecasts, which are referred to as embedded known loads, were also reviewed. The number, types, and size of projects that are included are shown in the two plots included below. All told there are 1230 embedded projects included in the GNA forecasting process that total 2040 MVA over the ten-year planning period. For comparison, in the last DIDF cycle there were 1123 embedded projects included in the GNA forecasting process that totaled 1789 MVA over the ten-year planning period which is a slightly less than (about 10% less) the current cycle's count of projects and MWh.

Figure 2-4: Embedded Load Growth Projects by Year

Embedded Load Growth Projects											
Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
MVA	816	538	253	149	103	55	27	36	37	27	2,040

Figure 2-5: Embedded Load Growth Projects Summary



The IPE validation review also included a review of the methodology SCE used to implement what they call embedded local known loads in the 2022 DIDF cycle, known as the Whirlpool method. It is a special method to implement the embedded known loads when the CEC load growth forecast for any year is smaller than the sum of the embedded known loads for that year. To address that eventuality, SCE developed a methodology, the "Whirlpool" method, to ensure that embedded known loads and economically driven load growth included in any year 1) do not exceed the CEC growth forecast for that year, 2) embedded known loads that are included are ones that have the highest Level of Certainty (LOC), and 3) all embedded known loads are in fact included in the forecast and none are "lost" in the process. The SCE Whirlpool method was used in the 2020, 2021 and this 2022 DIDF cycle.

The figures below (provided by SCE) show graphically, in simple terms, how the Whirlpool method works. The first three figures use example data, and the fourth figure shows the results of using the Whirlpool Method for this year's embedded known load projects. It includes the development and use of LOC values for each load (similar to those used in Forecast Certainty prioritization metric), an allocation methodology to allocate, as needed, portions of known loads into multiple years, and a method to ensure that the CEC IEPR values are not exceeded, and the known loads are eventually added when possible along with economic load growth.

Figure 2-6: Incorporate Embedded Known Load and Economic Growth (1 of 4)

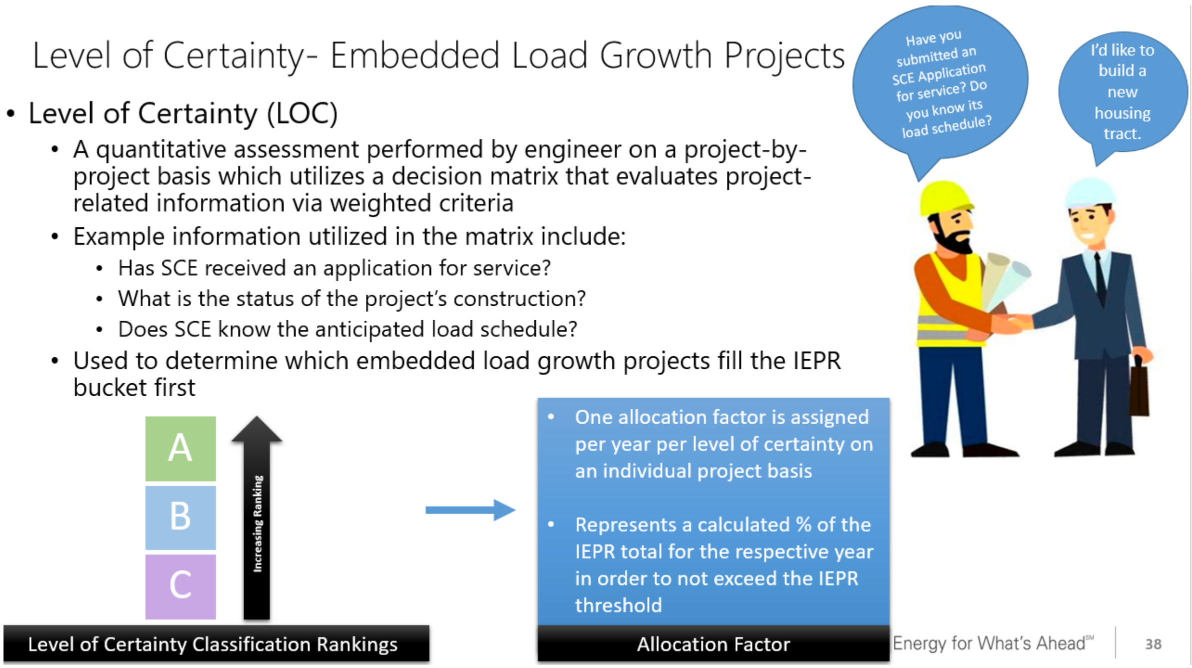


Figure 2-7: Incorporate Embedded Known Load and Economic Growth (2 of 4)

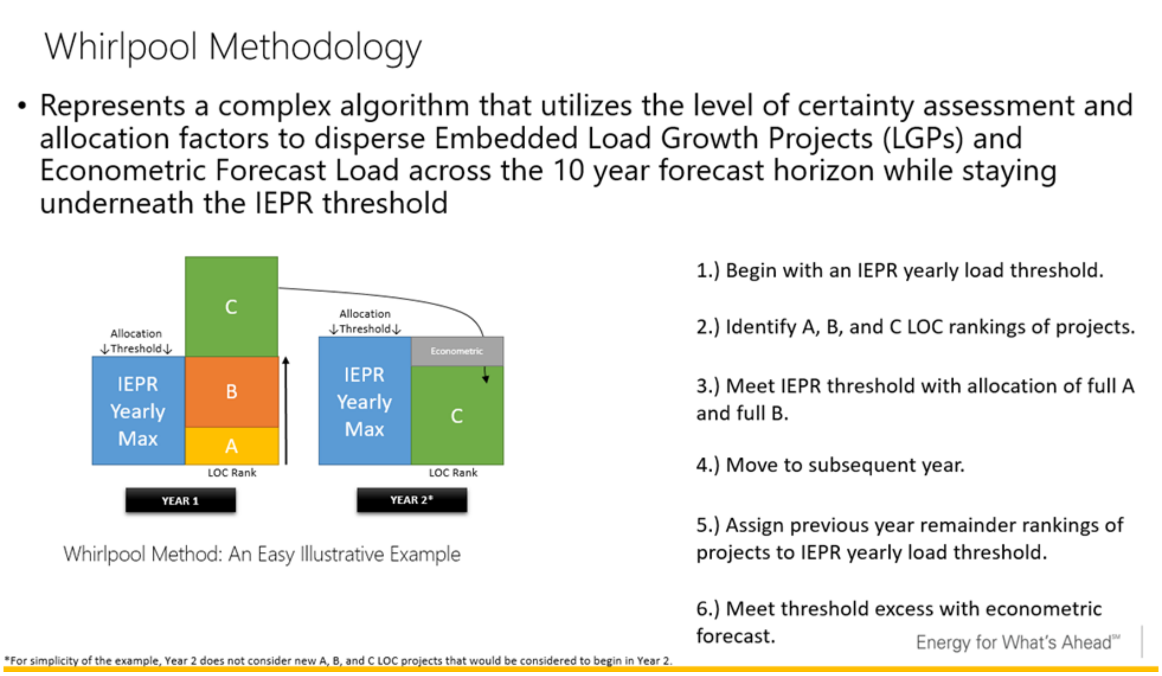


Figure 2-8: Incorporate Embedded Known Load and Economic Growth (3 of 4)

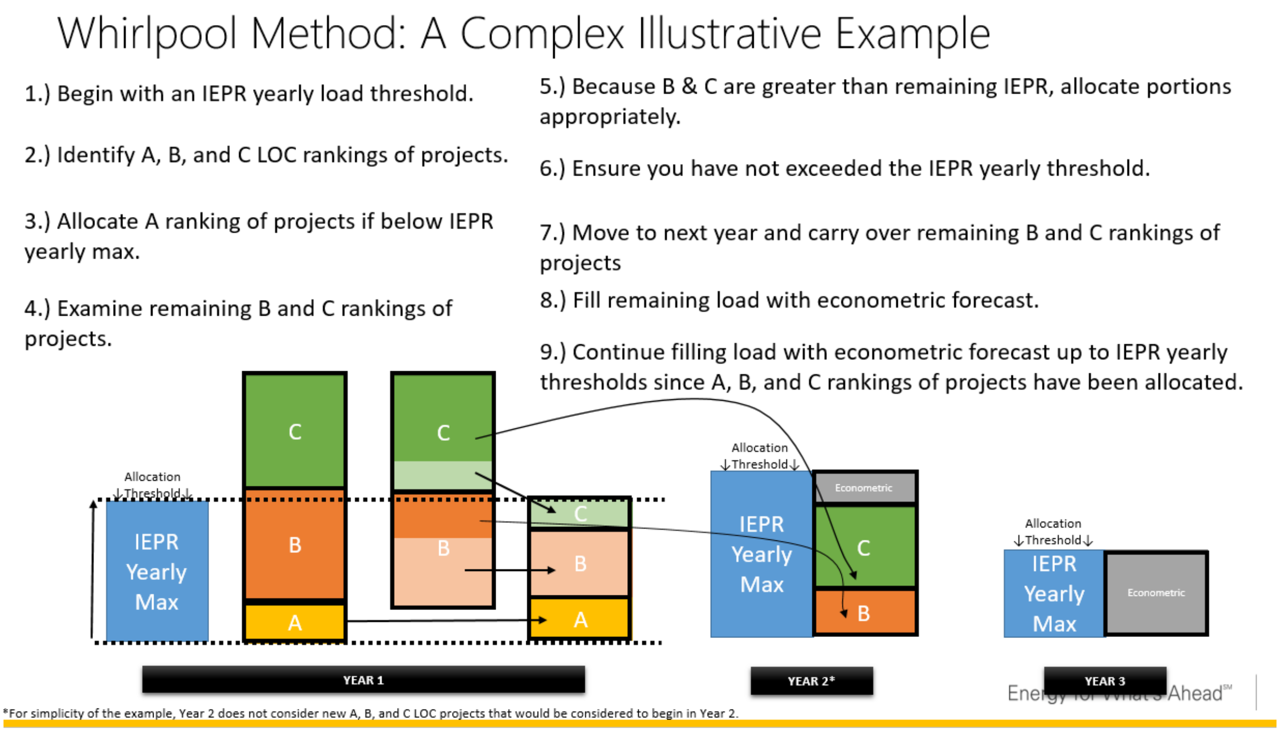
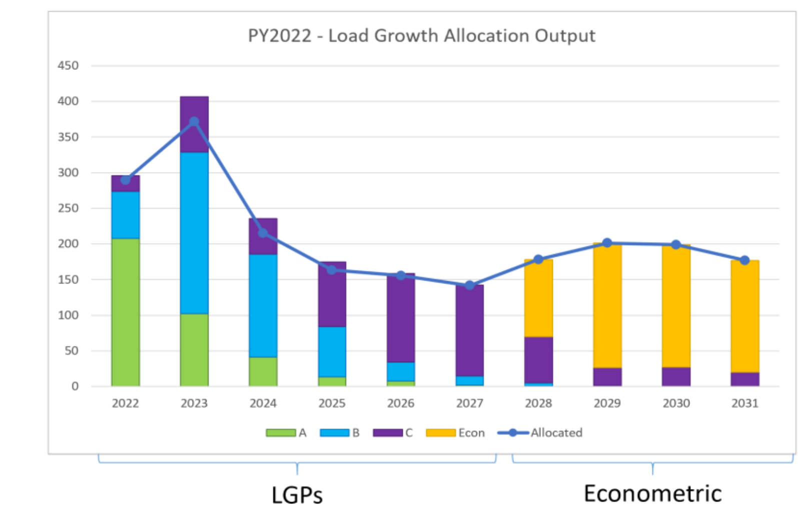
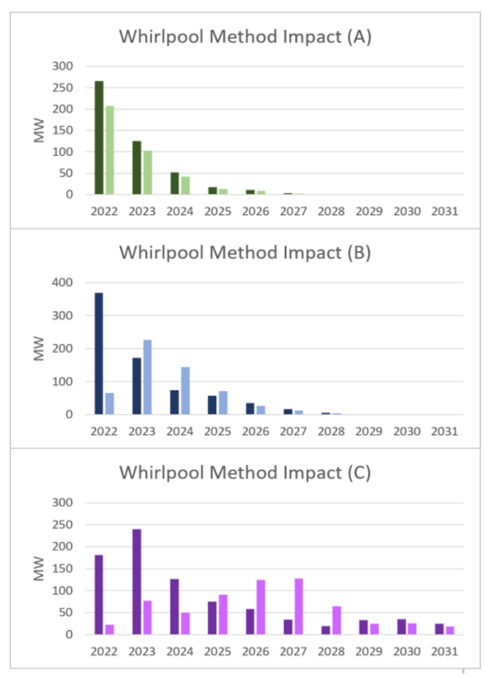


Figure 2-9: Incorporate 2022 Embedded Known Load and Economic Growth (4 of 4)



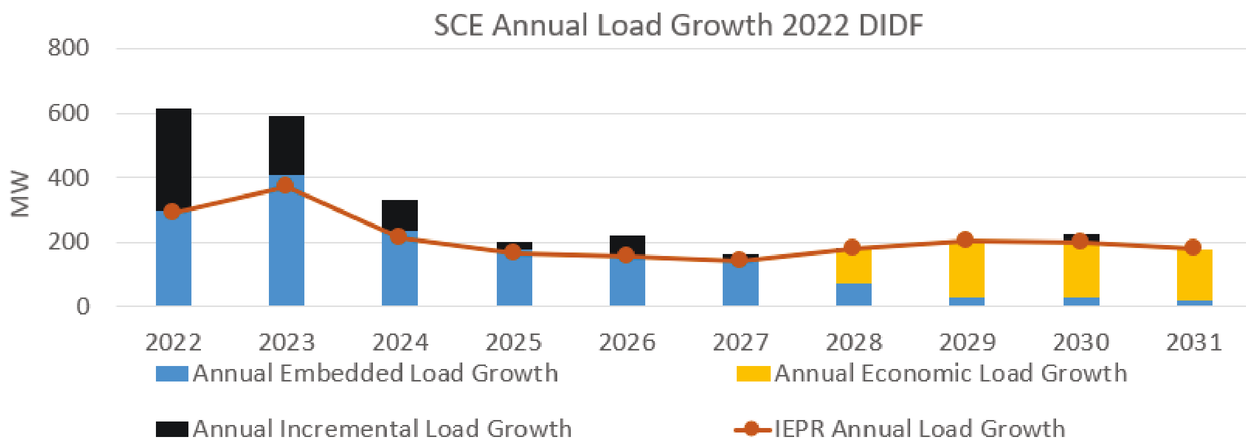


Allocation Factors by Year and Level of Certainty										
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
A	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
B	23.6%	66.1%	84.0%	100%	100%	100%	100%	100%	100%	100%
C	16.2%	26.2%	15.8%	27.9%	44.9%	71.8%	100%	100%	100%	100%

From the figure above we see the impacts of applying the Whirlpool method to the forecasts for the current DIDF cycle. We see that 2022 load growth include type A, B and C type embedded projects with the majority being Type A. Growth continues to be a mix of Type A, B and C projects until 2028 when some load growth is econometric. In the tenth-year, load growth is primarily econometric.

In summary, we see that the placement of IEPR load growth on the distribution systems for the first six years of the overall planning period is solely a function of embedded load growth projects. Allocation of the remaining IEPR load growth is allocated using econometric variables starting in year seven. Figure 2-10 shows how the embedded and incremental load growth projects are combined along with econometric load growth to form the total load growth for the ten-year planning period. Thus, for the first five years the incremental load growth projects total of 687 MW is about half the embedded growth projects total of 1273 MW for the period and about 58% of the IEPR growth for that same period.

Figure 2-10: SCE Annual Load Growth in 2022 DIDF



	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Annual Incremental Load Growth	320	185	94	27	61	21	4	0	24	0
Annual Embedded Load Growth	296	407	236	175	159	144	70	26	27	20
Annual Economic Load Growth	0	0	0	0	0	0	108	175	172	157
IEPR Annual Load Growth	289	372	215	163	156	142	178	201	199	177

In other words, for this cycle, the load growth that is used in SCE's annual DPP need development process that is allocated to circuits in the first six years of the planning period, is solely driven by embedded and incremental load growth projects. Econometric variables are then used in years seven and beyond to allocate to the circuit level the remining load growth in the CEC IEPR forecasts.

Utility Owned DER Projects

According to its filing, SCE did not evaluate new IOU-Owned DER solutions in conjunction with wires as part of its 2022 DPP. SCE is currently working on tools and processes to integrate DER alternative evaluation into future planning processes and plans to begin testing those tools and processes in its 2023 or 2024 DPP. There are however several IOU-owned distribution DER pilot projects, as listed in Table 11 of the SCE GNA/DDOR, that originated outside of SCE's annual DPP and are currently under development.

Line Segment Needs

SCE did not include needs at the line segment level in its GNA/DDOR. SCE is developing systems to facilitate the development of line segment needs at this time.

2.3. GNA - Observations, Conclusions and Recommendations

- We observe that in the past and including this DIDF cycle SCE has provided information for its incremental known load projects based upon information provided by its customers which captured peak needs which often does not consider the diversity of the customers loads. To capture the potential for the customers load diversity, SCE applies a discount factor (a value of less than 1.0) to the peak load data provided by the customer. This value varies depending upon the amount of information provided by the customer but generally ranges from 0.75 to 1.0. On average, for this cycle, this discount factor is approximately 0.78 for embedded and incremental known loads. For each known load, the peak value is adjusted for customer diversity by reducing the peak value by multiplying it by the discount factor before using in the DPP.

  By reporting known load values in the GNA/DDOR prior to adjusting for customer diversity the known load value appears in the GNA/DDOR to be larger than the load value actually used in the DPP by 22% (1-0.78). We recommend to present a clearer picture of how know loads are used in the DPP, that SCE report in the GNA/DDOR the known load values after they have been adjusted for customer load diversity.
- We observe that SCE uses a method to incorporate embedded known loads in its DPP that captures an estimate of each load's certainty using its LOC metric. We recommend that SCE incorporate the uncertainty of incremental known loads in its distribution planning process

3. Review of DDOR Report

Listed below is a high-level summary of the SCE DDOR Report that was filed on January 13, 2023. The DDOR Report includes descriptive material in PDF format and an Excel file which contains the data for planned investment and candidate deferral opportunity projects.

DDOR Report

The 2022 SCE DDOR report includes a narrative along with an Excel-based workbook containing three sheets: Planned Investment", "Candidate Deferral Projects," and "Candidate Deferral Add Info." The data reflected in the workbook represents a portion of SCE's traditional infrastructure projects that contribute to the operation of the distribution system and serves as the baseline for evaluating opportunities for DERs to potentially defer or avoid traditional distribution system investments. The three figures below, which are from the SCE 2022 DDOR Report, summarize the 2022 Candidate Deferral Projects in the DDOR (also referred to as Candidate Deferral Opportunities (CDO) in this report).

DDOR Planned Investments

Shown in the following table are the Planned Investments included in SCE's DDOR report. The total number of planned investments in the 2022 DDOR is 285 projects which compares to 238 planned investments in the 2021 DDOR for an increase of 20%. The table shows that a large number of the projects are in the Metro West and East Region, are predominantly distribution capacity in nature projects and 91% have an operating date in the first three years of the planning period compared to 94% in 2021.

Table 3-1: Planned Investments

Region	Distribution	Distribution VAR	Subtransmission	Total
Desert Region	31	7	4	42
Metro East Region	38	15	2	55
Metro West Region	45	6	2	53
North Coast Region	31	6	10	47
Orange Region	12	11	2	25
Other Region	1	0	0	1
Rurals Region	20	6	2	28
San Jacinto Valley Region	19	3	2	24
San Joaquin Region	6	0	4	10
Total	203	54	28	285

Distribution Service						Total
Capacity	Voltage	Reactive Power	Reliability, Capacity	Reliability, Voltage	Resiliency	
195	9	53	24	4	0	285

Operating Date										Total
2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	
102	121	37	13	9	1	1	1	0	0	285

Cost Estimate Basis

According to SCE, they do not track or build out project timelines based on Association for the Advancement of Cost Engineering (AACE) standards. As such, the AACE classifications being assigned to each project in the DDOR was SCE's best effort to correlate SCE business process and AACE classifications. SCE organized the current project list into distinct projects group types.

An estimated average AACE timeline for each classification was created for each specific project group types based on AACE definitions and averaging historical execution information. The timeline outlined the average days from operating date for each AACE classification for each project group type. That timeline was applied to each project to assign an AACE classification.

Also, SCE cross-references 2022 planned investments with previous DDORs as far back to 2019 when DDOR Project IDs were introduced. This information allows one to determine if planned investments were in multiple DDORs and how they might have changed. SCE did not evaluate new IOU-Owned DER solutions in conjunction with wires as part of its 2022 DPP. SCE is currently working on tools and processes to integrate DER alternative evaluation into future planning processes and plans to begin testing those tools and processes in its 2023 or 2024 DPP. However, there are several IOU-owned distribution DER pilot projects, which are listed in Table 11 of the DDOR, that originated outside of SCE's annual DPP and are currently under development. The table lists five pilot projects with three scheduled for operation in 2023 and two in 2025.

3.1. DDOR Report Planned Investments - Observations, Conclusions and Recommendations

None at this time.

4. DDOR Report – Review of Screening, Prioritization, and Selection of Pilot Projects

This section reviews the methodology that SCE used to screen CDO projects, prioritize projects, and select projects for procurement through an RFO or a PP or SOC Pilot. Note that in the 2022 DIDF cycle the methodology was used twice, the first time in preparation of the abbreviated DDOR report filed on September 2, 2022 and the second time in preparation of the final GNA/DDOR report filed on January 13, 2023. The results of both of these applications of the methodology are discussed in this section. Results in the September 2022 filing are called Interim and the results in the January 2023 filing are called Final.

4.1. Project Screens

This section contains a discussion of the screens that SCE used to develop its candidate deferral projects list from potential projects that were developed in its abbreviated GNA/DDOR process. SCE effectively used both a technical screen and a timing screen to screen projects in the process of developing a candidate deferral projects list. The screens included:

- Screening out projects that are not one of the four service types previously described.
- Screening out projects that fall within the first three years. This essentially allows only projects in 2025 and beyond to pass through the timing screen.

A summary of the final projects that resulted from the application of the timing and service screens are summarized in Figure 4-1 below.

Table 4-1: Final Candidate Deferral Project Opportunities by Type, Region, Service and Operating Date

Region	Project Type			Total
	Line Only	Substation and Line	Substation Only	
Desert Region	1	0	1	2
Metro East Region	3	0	1	4
Metro West Region	1	0	1	2
North Coast Region	6	1	1	8
Orange Region	2	0	0	2
Rurals Region	0	1	0	1
San Jacinto Valley Region	1	2	1	4
San Joaquin Region	2	0	0	2
Total	16	4	5	25

Distribution Service						Total
Capacity	Voltage	Reactive Power	Reliability, Capacity	Reliability, Voltage	Resiliency	
18	0	1	5	1	0	25

Operating Date										Total
2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	
0	0	0	13	9	1	1	1	0	0	25

SCE's initial 2022 DDOR Filing presented 17 candidate deferral projects. With the finalization of SCE's DPP update, there are nine additional candidate deferral projects identified and one candidate deferral project previously in Tier 3 was removed from the list as its operating date was postponed to outside of the five-year reporting window. Among the nine new candidate deferral projects, two are ranked in Tier 1, three are in Tier 2, and four are in Tier 3. These new projects are identified in the next section in Table 4-2.

4.2. Project Prioritization

This section contains a discussion of the prioritization process used by SCE to prioritize its candidate deferral projects and a discussion of the various metrics SCE used during that process. This is the second DIDF cycle that the three utilities are using a jointly developed project prioritization methodology in the form of an Excel workbook. The joint workbook used in the 2022 DIDF is slightly different that the one used in the 2021 DIDF. Small changes were made to improve the functionality of the workbook and were reviewed by the ED and IPE and approved by the ED.

The Joint Workbook maintains the use of the three previously CPUC approved metrics – Cost-Effectiveness, Forecast Certainty, and Market Assessment. These three metrics have both quantitative and qualitative sub-metrics. The quantitative sub-metrics are used to rank projects and the qualitative sub-metrics are used to apply engineering judgment and past experience to flag when projects are less likely to be successfully deferred by a DER solution.

The results of the application of these three metrics are demonstrated in the "final" SCE project prioritization (including Licensing Projects) (for the candidate deferral opportunities included in the January 23, 2023 DDOR filing) which is shown in Table 4-1. Results included in the September DDOR are labeled "Interim" while results included in the January 13, 2023 are labeled "Final". A description of the Joint Prioritization Workbook Template methodology is included later in this section. Note the new projects included the final results are shown in bold in the Table 4-2.

Table 4-2 Final Tier Ranking of Candidate Deferral Opportunity Projects.

Tier	Project Description	Operation Date	Max Deficiency (MW)
1	Rebuild Saugus Haskell 66 kV Subtransmission Line	2026	4.0
	Rebuild Mesa-Narrows 66 kV Subtransmission Line	2025	1.5
	Install a New 12kV Circuit at Triton 115/12 kV Substation	2026	3.7
	Rebuild Santa Clara-Colonia 66 kV Subtransmission Line	2026	21.9
	Install a New 12 kV Circuit at Irvine 66/12 kV Substation	**2025**	**3.4**
	Install a New Transformer at Alessandro 115/33 kV Substation	2025	2.0
	Install a New 16 kV Circuit at Bullis 66/16 kV Substation	**2025**	**2.8**
	Install Rector-Recto-Riverway No. 266 kV Subtransmission Line	2026	21.0
	Rebuild Elizabeth Lake-Pitchgen 66 kV Subtransmission Line	2026	13.2
2	**Install a New 16 kV Circuit at Elizabeth Lake 66/16 kV Substation**	**2026**	**5.6**
	Upgrade Transformers at North Oaks 66/16 kV Substation	2025	21.1
	Reconfigure Browning - Delano 66 kV Subtransmission Line	**2025**	**8.5**
	Install a New Transformer at Mira Loma 66/12 kV Substation	2025	8.4
	Install a New 12 kV Circuit at Bloomington 66/12 kV Substation	**2025**	**5.7**
	Install a New 12 kV Circuit at Chase 66/12 kV Substation	2025	3.6
	Cal City Project: Construct a New 115/12 kV Substation and Construct New 115 kV Subtransmission Lines	2028	80.7
	Del Valle Project: Construct a New 66/16 kV Substation and Construct New 16 kV Circuits	2027	55.3
3	Alberhill System Project: Construct a New 500/115 kV Substation and associated 500 kV source lines and 115 kV lines	2029	286.3
	Construct a New 16 kV Circuit at Gonzales 66/16 kV Substation	2025	16.8
	Increase Sunnyside 66/12 kV Substation by Eliminating Limiting Components	**2026**	**1.0**
	Install a New 16 kV Circuit at Saugus 66/16 kV Substation	**2026**	**16.2**
	Install a New 12 kV Circuit at Talbert 66/12 kV Substation	**2025**	**4.6**
	Upgrade Transformer and Construct a New 12 kV Circuit at Valley 115/12 kV Substation	2025	15.7
	Install a New Capacitor at Devers 220/115 kV Substation	2026	70.0
	Install a New 12 kV Circuit at Bain 66/12 kV Substation	**2025**	**4.7**

Shown in Table 4-3 is a comparison of the initial and final CDO projects and their ranking into Tiers. We see in the table the nine projects that were added in the final results (listed last) and how their addition has changed the tier ranking of the initial CDO projects.

Table 4-3: Comparison of Ranking of Candidate Deferral Opportunity Projects

Project ID	Project Description	9/2 Tiers	1/13 Tiers
DDOR_2022_6698	Rebuild Elizabeth Lake-Pitchgen 66 kV Subtransmission Line	Tier 1	Tier 1
DDOR_2022_8509	Rebuild Saugus-Haskell 66 kV Subtransmission Line	Tier 1	Tier 1
DDOR_2022_6055	Rebuild Mesa-Narrows 66 kV Subtransmission Line	Tier 1	Tier 1
DDOR_2022_DSP26358_688019	Install a New 12kV Circuit at Triton 115/12 kV Substation	Tier 1	Tier 1
DDOR_2022_8476	Install a New Transformer at Alessandro 115/33 kV Substation	Tier 1	Tier 1
DDOR_2022_8425	Rebuild Santa Clara-Colonia 66 kV Subtransmission Line	Tier 1	Tier 1
DDOR_2022_6871	Install Rector-Riverway No. 2 66 kV Subtransmission Line	Tier 2	Tier 1
DDOR_2022_DSP35666	Upgrade Transformers at North Oaks 66/16 kV Substation	Tier 3	Tier 2
DDOR_2022_8481	Install a New Transformer at Mira Loma 66/12 kV Substation	Tier 2	Tier 2
DDOR_2022_DSP34759_334554	Install a New 12kV Circuit at Chase 66/12 kV Substation	Tier 2	Tier 2
DDOR_2022_8256	Cal City Project: Construct a New 115/12 kV Substation and Construct New 115 kV Subtransmission Lines	Tier 2	Tier 2
DDOR_2022_4800	Del Valle Project: Construct a New 66/16 kV Substation and Construct New 16 kV Circuits	Tier 2	Tier 2
DDOR_2022_8325_339553	Construct a New 16 kV Circuit at Gonzales 66/16 kV Substation	Tier 3	Tier 3
DDOR_2022_6092	Alberhill System Project: Construct a New 500/115 kV Substation and associated 500 kV source lines and 115 kV lines	Tier 3	Tier 3
DDOR_2022_TSP STV35570	Install a New Capacitor at Devers 220/115 kV Substation	Tier 3	Tier 3
DDOR_2022_8469_577046	Upgrade Transformer and Construct a New 12kV Circuit at Valley 115/12 kV	Tier 3	Tier 3
DDOR_2022_8511_543018	Install a New 12 kV Circuit at Irvine 66/12 kV Substation		Tier 1
DDOR_2022_DSP35738_532018	Install a New 16 kV Circuit at Bullis 66/16 kV Substation		Tier 1
DDOR_2022_8502_530023	Install a New 12 kV Circuit at Bloomington 66/12 kV Substation		Tier 2
DDOR_2022_8068	Reconfigure Browning - Delano 66 kV Subtransmission Line		Tier 2
DDOR_2022_7978_959298	Install a New 16 kV Circuit at Elizabeth Lake 66/16 kV Substation		Tier 2
DDOR_2022_DSP35747	Increase Sunnyside 66/12 KV Substation by Eliminating Limiting Components		Tier 3
DDOR_2022_8505_429067	Install a New 12 kV Circuit at Talbert 66/12 kV Substation		Tier 3
DDOR_2022_06328_459030	Install a New 16 kV Circuit at Saugus 66/16 kV Substation		Tier 3
DDOR_2022_DSP35713_430018	Install a New 12 kV Circuit at Bain 66/12 kV Substation		Tier 3
DDOR_2022_8438	Install a New Capacitor at Channel Island Substation	Tier 3	

Considered for third party or IOU owned DER deferral in the 9/2 filing

Added to the DER deferral recommendation in the 1/13 filing

New Candidate Deferral Projects in the 1/13 filing

SCE developed recommendations (Table 4-4) for which projects should be considered for the SOC and PP pilots using a selection methodology for each type of pilot that used as its starting point the ranking results of the Joint Prioritization Workbook Template. A review of those methodologies is included later in this section. Note that this table recommends that nine projects be placed into Tier 1, and normally Tier 1 projects are considered for procurement through the RFO process.

In the January 13, 2023 GNA/DDOR Report SCE recommended the following RFO, SOC and PP pilot projects (based upon its selection methodology) to meet CPUC ruling with respect to the minimum number and type of projects to be included in the SOC and PP pilots:

Table 4-4: Final SCE Recommendations for All Types of Procurement

Project	Tier	Operating Date	Max 10 Year Deficiency (MW)	Recommendation
Rebuild Saugus-Haskell 66 kV Subtransmission Line	1	2026	4.0	Partnership Pilot
Rebuild Mesa-Narrows 66 kV Subtransmission Line	1	2025	1.5	IOU-Owned DER
Install a New 12 kV Circuit at Triton 115/12 kV Substation	1	2026	3.7	DIDF RFO
Rebuild Santa Clar-Colonia 66 kV Subtransmission Line	1	2026	21.9	In 2021-2022 Partnership Pilot
Install a New 12 kV Circuit at Irvine 66/12 kV Substation	1	2025	3.4	IOU-Owned DER
Install a New Transformer at Alessandro 115/33 kV Substation	1	2025	2.0	SOC Pilot
Install a New 16 kV Circuit at Bullis 66/16 kV Substation	1	2025	2.8	Partnership Pilot
Install Rector-Riverway No. 2 66 kV Subtransmission Line	1	2026	21.0	Partnership Pilot
Rebuild Elizabeth Lake-Pitchgen 66 kV Subtransmission Line	1	2026	13.2	Can be deferred by Existing DIDF DER project
Upgrade Transformers at North Oaks 66/16 kV Substation	2	2025	21.1	Partnership Pilot
Install a New Transformer at Mira Loma 66/12 kV Substation	2	2025	8.39	IOU-Owned DER

As we can see from the above Final results table, SCE has proposed 5 CDOs for pilots - 4 for PP pilots and 1 for SOC pilot thus meeting the CPUC's required minimum number of pilot projects. In addition, SCE has recommended one project for RFO in this cycle, Two Tier 1 projects that would be a logical RFO candidate, were not recommended for procurement because they were currently involved in an ongoing SCE procurement.

Prioritization Metrics Included in Joint Prioritization Workbook Template

Below we provide a high-level discussion of the metrics used and workings of the Joint Prioritization Workbook Template.

The Workbook uses three areas for ranking projects – Cost-Effectiveness, Forecast Certainty, and Market Assessment. These three areas have quantitative metrics and qualitative metrics. The quantitative metrics are used to rank the CDOs and to place into one of three Tiers – either Tier 1, Tier 2, or Tier 3. The qualitative metrics are used to Flag projects for project attributes that the utility believes, based upon past experience, would make a project unlikely to be deferred by a DER. The Flags are applied after the projects are ranked using the quantitative metrics and override the ranking by automatically placing them into Tier 3. These metrics are listed below.

Quantitative Metrics
For Cost-Effectiveness

- LNBA ($/MW-yr)
- LNBA ($/MWh-yr)

For Forecast Certainty

- Grid Need Certainty (SCE used a Level of Certainty Questionnaire completed by Planning Engineers)

For Market Assessment

- Duration of Need (Hours)
- Capacity Need (MW)/Circuit

Qualitative Metrics
For Cost-Effectiveness

- Unit Cost of Traditional Mitigation ($) (Flagged if project capital cost is below a threshold value set by each utility. Not used by SCE this cycle.)

For Forecast Certainty

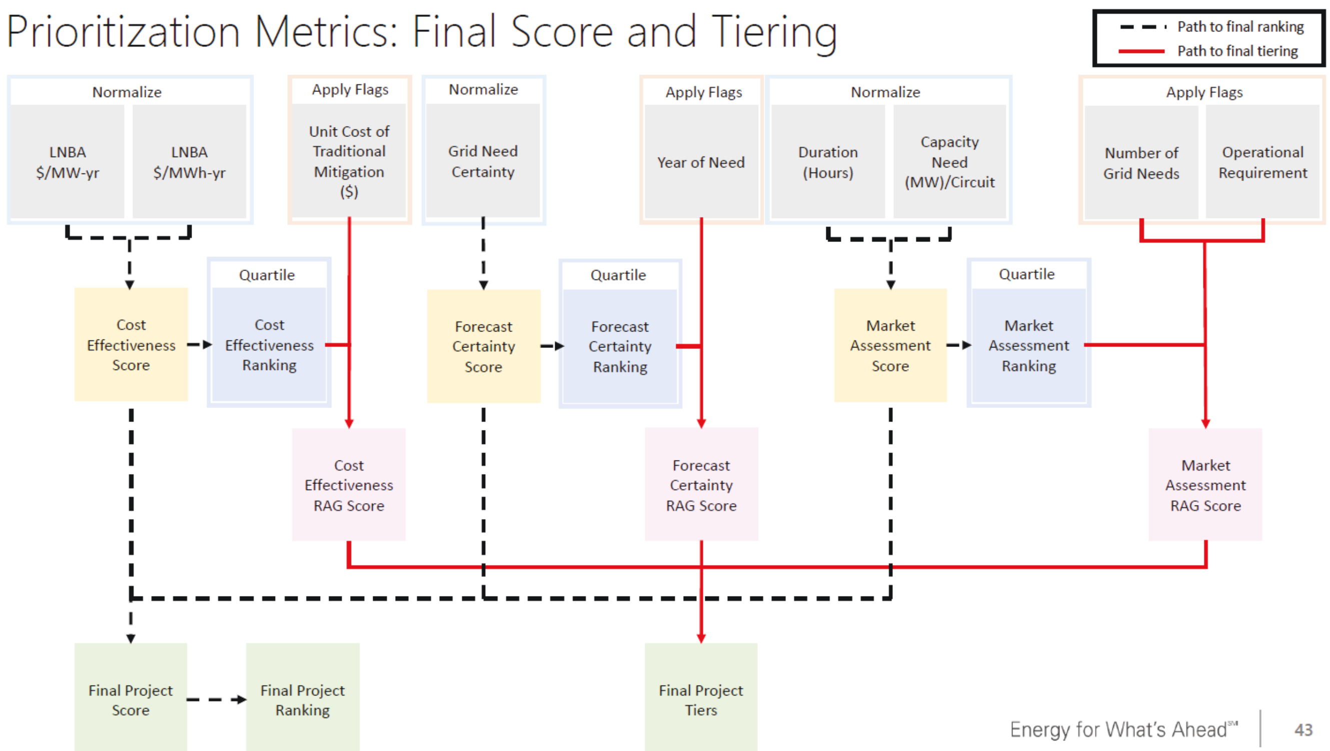
- Year of Need (Flagged if Operational date is after threshold year set by utility. Not used by SCE this cycle.)

For Market Assessment

- Operational Requirement (Flagged if Real Time response and/or islanding operation needed by DER. Used by SCE this cycle.)
- Number of Grid Needs (Flagged if number of needs exceed threshold value set by utility. Not used by SCE this cycle.)

The overall Workbook processes are shown in Figure 4-1 below (from SCE's DPAG PPT).

Figure 4-1: Prioritization Metrics Methodology



The LOC questionnaire used to develop the Forecast Certainty score includes guidelines for developing the LOC score for each load growth driver associated to a candidate deferral project. The questionnaire used by SCE is shown in Figure 4-2. You can see that providing concrete components, milestones to be met and associated score, and overall ranking that the questionnaire supports for uniformity in assigning scores to each of the components of the questionnaire and thus to each project.

Figure 4-2: Level of Certainty Questionnaire

	Score	0	1	2	3	Weight
Customer Information	SCE Application for Service	N/A	Received	N/A	N/A	1
	Construction Status	Not Started	Grading	Construction Started/Existing Building	Construction Complete	3
	Low/High Voltage Switchgear	None	Design / Drawings Received	Approved	Authority Having Jurisdiction (AHJ) signoff / Installed on-site	2
	Load Schedule	None	Range Provided but no firm values	Received but not validated	Data Confirmed	1
	Status of Environmental Review or other Regulatory efforts	Not Started	In Progress / Not Required	Filed	Approved	1
SCE Information	Added Facilities	None	Customer Moving Forward	N/A	Added Facilities Agreement Complete	2
	Design Status	Not Started	In Preliminary Design	Final Design Approved	Customer Invoiced	1

4.3. Selection of Projects for Standard Offer Contract and Partnership Pilot

The CPUC Ruling established the SOC and PP pilots and directed the utilities to propose pilots in each DIDF cycle as follows:

- At least one Tier 1 project for the SOC pilot
- At least one Tier 1 and two Tier 2 or 3 projects for the PP pilot

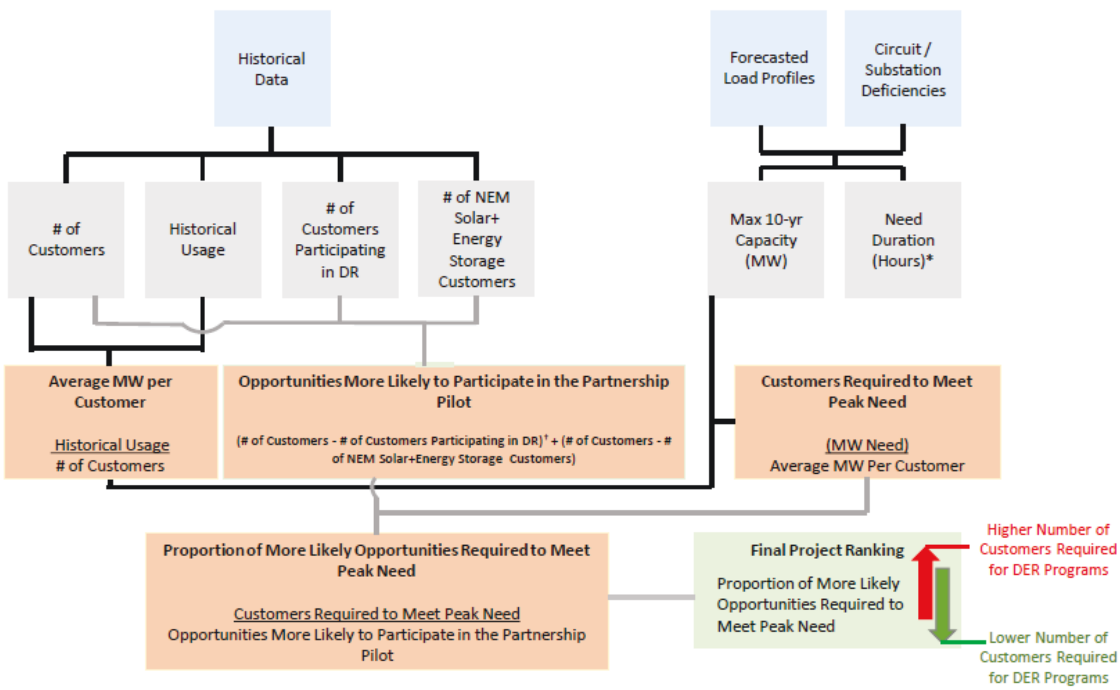
Partnership Pilot Project Selection

In this section we review the methodology that SCE used to select the projects that it recommended for PP pilots.

SCE developed a methodology to assist in the selection of CDO projects that it would recommend for PP pilots. This methodology, which is same as last year's, uses the results of the Joint Prioritization Workbook Template ranking/tiering of the CDOs as the starting point and then applies additional criteria that ranks Tier 1 projects and Tier 2/3 projects, respectively, according to the relative availability of opportunities for BTM DERs to address the circuit needs associated with the project.

This methodology uses the average MW relief per customer and the number of customers that could potentially participate in a BTM solution, taking into account those customers that are most likely to participate. In that process the methodology considers customers with existing PV plus battery installation on Net Energy Metering (NEM) as less likely to participate than other customers and thus are not included in the tally of more likely DER participants. Also, the methodology assumes that existing demand response customers are less likely to participate if the duration of the need is more than 4 hours. SCE's final recommended methodology reflects modifications made in response to comments at the 2021 DPAG; final methodology is shown graphically in Figure 4-3. The final ranking is based on the proportion of customers required to meet the peak need expressed as a percentage of the total customers that are likely available to participate in DER programs. A smaller percentage value will result in a higher rank.

Figure 4-3: Partnership Pilot Selection Process



The final results of the application of the final methodology are shown in Table 4-5.

Table 4-5: SCE Final Partnership Pilot Rankings – Tier 1

Project Description	DSR	Operating Date	Max 10 Year Deficiency (MW)	PP Ranking
Rebuild Mesa-Narrows 66 kV Subtransmission Line	Reliability, Capacity	2025	1.5	1
Install a New Transformer at Alessandro 115/33 kV Substation	Capacity	2025	2.0	2
Rebuild Saugus-Haskell 66 kV Subtransmission Line	Reliability, Capacity	2026	4.0	3
Rebuild Elizabeth Lake-Pitchgen 66 kV Subtransmission Line	Reliability, Capacity	2026	13.2	4
Install a New 16 kV Circuit at Bullis 66/16 kV Substation	Capacity	2025	2.8	5
Rebuild Santa Clar-Colonia 66 kV Subtransmission Line	Reliability, Capacity	2026	21.9	6
Install Rector-Riverway No. 2 66 kV Subtransmission Line	Reliability, Capacity	2026	21.0	7
Install a New 12 kV Circuit at Irvine 66/12 kV Substation	Capacity	2025	3.4	8
Install a New 12 kV Circuit at Triton 115/12 kV Substation	Capacity	2026	3.7	9

Table 4-6: SCE Final Partnership Pilot Rankings – Tier 2/3

Project Description	Tier	DSR	Operating Date	Max 10 Year Deficiency (MW)	PP Ranking
Increase Sunnyside 66/12 kV Substation by Elimination Limiting Components	3	Capacity	2026	1.0	1
Install a New Transformer at Mira Loma 66/12 kV Substation	2	Capacity	2025	8.4	2
Install a New 12 kV Circuit at Chase 66/12 kV Substation	2	Capacity	2025	3.6	3
Upgrade Transformers at North Oaks 66/16 kV Substation	2	Capacity	2025	21.1	4
Install a New 12 kV Circuit at Bloomington 66/12 kV Substation	2	Capacity	2025	5.7	5
Install a New 16 kV Circuit at Elizabeth Lake 66/16 kV Substation	2	Capacity	2026	5.6	6
Alberhill System Project: Construct a New 500/115 kV Substation and associated 500 kV source lines and 115 kV lines	3	Capacity	2029	286.3	7
Reconfigure Browning – Delano 66 k V Subtransmission Line	2	Reliability, Voltage	2025	8.5	8
Upgrade Transformer and Construct a New 12 kV Circuit at Valley 115/12 kV Substation	3	Capacity	2025	15.7	9
Install a New 12 kV Circuit at Talbert 66/12 kV Substation	3	Capacity	2025	4.6	10
Install a New 12 kV Circuit at Bain 66/12 kV Substation	3	Capacity	2025	4.7	11
Install a New 16 kV Circuit at Saugus 66/16 kV Substation	3	Capacity	2026	16.2	12
Construct a New 16 kV Circuit at Conzales 66/16 kV Substation	3	Capacity	2025	16.8	13

Install a New Capacitor at Devers 220/115 kV Substation	3	Reactive Power	2026	70.0	14
Cal City Project: Construct a New 115/12 kV Substation and Construct New 115 kV Subtransmission Lines	2	Capacity	2028	80.7	15
Del Valle Project: Construct a New 66/16 kV Substation and Construct New 16 kV Circuits	2	Capacity	2027	55.3	16

Standard Offer Contract Project Selection

SCE also developed a methodology to assist in the selection of CDO projects that it would propose for SOC pilots. This methodology uses the results of the Joint Prioritization Workbook Template ranking/tiering of the CDOs as the starting point and then applies additional criteria that ranks Tier 1 projects according to the relative availability of land near the relevant circuitry for IFOM DER installation(s). The process used is shown graphically in Figure 4-4. SCE used a metric of Number of Customers/Circuit Mile to capture the potential for open land available nearby for developing in front of the meter DER solutions. SCE also filtered out certain technical projects (Underground Cable Temperature driven projects) based upon their experience with in-front-of the meter energy storage's difficulty addressing these types of projects. Given that the SOC deadline per the CPUC ruling called for implementing the SOC procurement process prior to the DPAG meeting there was little discussion of this selection process at the DPAG.

Table 4-7 shows the results of the application of the final methodology for ranking projects for the SOC pilot.

Figure 4-4: Standard Offer Contract Selection Methodology

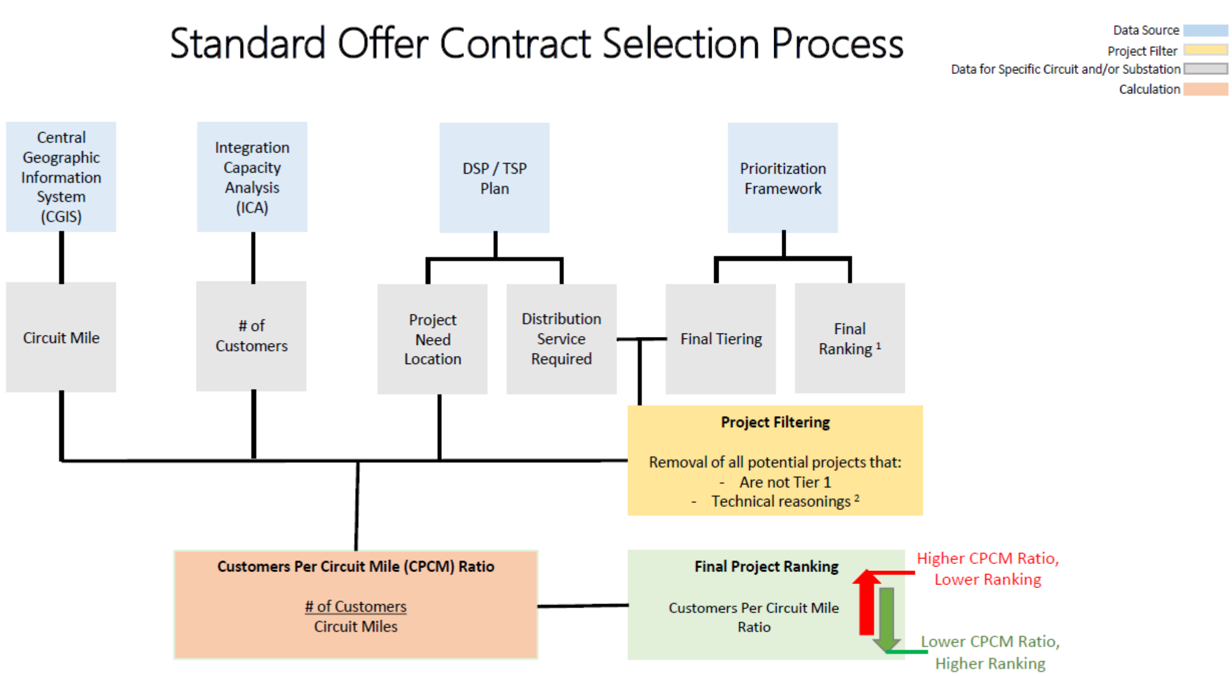


Table 4-7: SCE Standard Offer Contract Ranking

Project Description	DSR	Operating Date	Max 10 Year Deficiency (MW)	SOC Ranking
Install a New Transformer at Alessandro 115/33 kV Substation	Capacity	2025	2.0	1
Rebuild Elizabeth Lake-Pitchgen 66 kV Subtransmission Line	Reliability, Capacity	2026	13.2	2
Rebuild Santa Clar-Colonia 66 kV Subtransmission Line	Reliability, Capacity	2026	21.9	3
Install a New 12 kV Circuit at Triton 115/12 kV Substation	Capacity	2026	3.7	4
Rebuild Mesa-Narrows 66 kV Subtransmission Line	Reliability, Capacity	2025	1.5	5
Install a New 16 kV Circuit at Bullis 66/16 kV Substation	Capacity	2025	2.8	6
Rebuild Saugus-Haskell 66 kV Subtransmission Line	Reliability, Capacity	2026	4.0	7
Install Rector-Riverway No. 2 66 kV Subtransmission Line	Reliability, Capacity	2026	21.0	8
Install a New 12 kV Circuit at Irvine 66/12 kV Substation	Capacity	2025	3.4	9

4.3.1. Project Prioritization and Pilot Selection Methodology- Observations Conclusions and Recommendations

Prioritization

- We observe in the list of CDOs that in this cycle there were several Pre and Post Application projects and two projects that were involved with ongoing SCE procurement processes and for all intents and purposes these projects are not likely candidates to be recommended for procurement. There is the potential for such projects to affect the outcome of the prioritization. For example, to use an extreme case if there were 4 such projects and they all ended up in Quartile 1 for CE and there can only be 4 Quartile 1 projects (because there are 16 CDOs) that would mean that no other project could receive a Green CE score. This would reduce the likely of having projects in Tier 1. We do not think that sort of impact occurred in this cycle, but it is possible to happen in a future cycle.
- For that reason, we recommend that the utilities provide a prioritization with all projects included as they do now and to also provide a second one with such projects removed.
- We observe that the Flag mechanism allows utilities to consider their past experience in flagging projects. Such flags place projects into Tier 3 regardless of the ranking of projects using the quantitative metrics. For this reason, the threshold values used by the three utilities should continue to be reviewed to ensure their appropriateness. We noted that SCE chose not to use any of the flags in this cycle except the flagging of Alberhill because it has an islanding operation need.

- We observe that the Forecast Certainty quantitative metric is largely driven by a utility specific certainty rating "questionnaire". SCE's is included as Figure 4-2 previously discussed. This questionnaire seems to focus on the uncertainty of the forecasted load driving a project materializing as predicted. In other words, it is capturing the risk that the load will continue to warrant the need to take action – either build the wires project or enter into a cost-effective DER contract. Other utilities "questionnaire" seems to be driven in part or largely by the risk of additional load materializing that is not yet forecasted but could possibly materialize and make the DER solution potentially undersized or possibly unnecessary.
  These are certainly two types of forecast uncertainty that could impact ratepayers. <u>We recommend that this particular issue be an agenda item for the next DIDF reform stakeholder webinar early in the next DIDF cycle.</u>

  The IPE compares the methodology used by the three IOUs for determining the Forecast Certainty score and summarize that comparison in the IPE Post DPAG Report and, as appropriate, develops recommendations for potential improvement,

5. Review of SCE Prioritization of Candidate Deferral Projects and Pilot Selections

In this section we review the work that the IPE did on the projects that SCE initially recommended for inclusion in Tiers 1-3 and those that were eventually recommended for RFO, SOC and PP pilots. The discussion in this section deals with the information regarding the ranking of projects included in the DDOR Report and the projects proposed for the two pilots as presented at the SCE DPAG and DPAG Follow-up Webinars. In the process we examined projects that were not in Tier 1 but were potentially a Tier 1 project or strong candidate for consideration for the SOC or PP pilots.

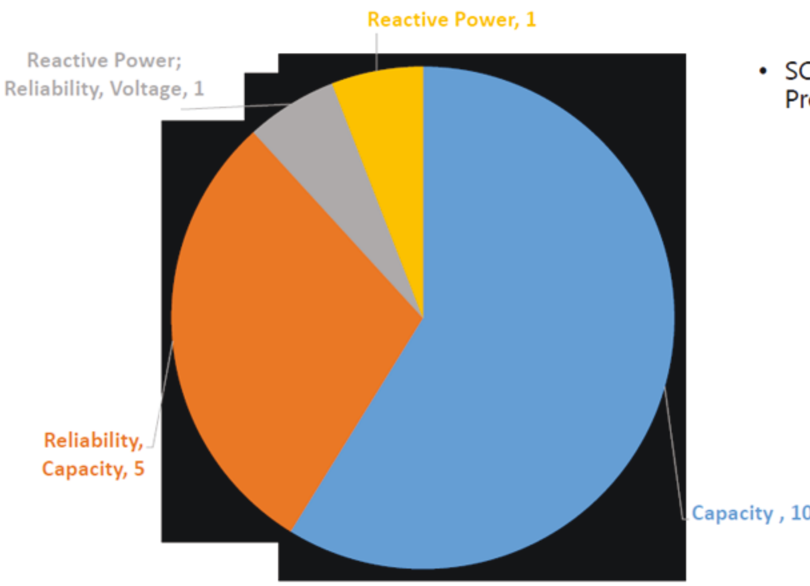
We believe that the Cost Effectiveness category, in general, is very important to the overall ranking process in that if there is not sufficient funds/budget[5] to develop and operate a DER solution that is cost effective (one that results in a bid that is below the cost cap) then the other two categories become less important. For this reason, we examined candidate projects with strong Cost Effectiveness metric values that were not in Tier 1. We also examined projects that were generally close to Tier 1.

It must be noted that if a project looks favorable on a cost-effectiveness basis it does not mean that it should automatically receive an overall high ranking because there may be significant issues in the other two prioritization categories that could result in a lower overall ranking/likelihood of success.

5.1. Summary of the Review of the Initial SCE Prioritization and Ranking

[5] Funds/budget in this instance can also be thought of as head room – economic space in which to develop a profitable project and still be under the cost cap used to determine if a bid or collection of bids are cost effective

Figure 5-1: Initial Breakdown of Candidate Deferral Projects by Type



- SCE 2022 DDOR includes 17 Candidate Deferral Projects
  - 9 candidate deferral projects primarily on the sub-transmission system (e.g.,115kV, 66kV)
    - Of these, 1 is a Pre-Application project and 1 is a Post-Application project
  - 8 candidate deferral projects primarily on the distribution system (e.g., 33kV, 16kV, 12kV)
    - Of these, 1 is Pre-Application project

SCE's initial recommendations regarding what Tiers for the 17 candidate deferral opportunity projects should fall in are shown in Figure 5-1. Figure 5-1 lists all of the CDOs and their ranking for each of the three metrics and their recommended Tiering (1, 2 or 3). SCE's initial recommendation regarding CDO projects for RFO, SC and PP procurement are shown in Figure 5-2. During the DPAG SCE summarized that 3 of the 17 were Pre or Post Application projects and that two of the Tier 1 CDOs were currently involved in an ongoing SCE procurement process and not recommended for procurement. These two projects are shown at the bottom of the table in Figure 5-3. In Figure 5-2 SCE recommended 6 projects proceed to procurement, 4 for PP and 1 each for SOC and RFO.

Figure 5-2: Initial Tier Recommendations for Candidate Deferral Projects

Rank	Name	Cost Effectiveness	Forecast Certainty	Market Assessment	Tier
1	Rebuild Saugus-Haskell 66 kV Subtransmission Line	2	1	3	Tier 1
2	Rebuild Mesa-Narrows 66 kV Subtransmission Line	1	14	1	Tier 1
3	Install a New 12 kV Circuit at Triton 115/12 kV Substation	8	2	7	Tier 1
4	Install a New Transformer at Alessandro 115/33 kV Substation	5	9	2	Tier 1
5	Rebuild Santa Clara-Colonia 66 kV Subtransmission Line	10	4	12	Tier 1
6	Install Rector-Riverway No. 2 66 kV Subtransmission Line	7	6	11	Tier 2
7	Upgrade Transformers at North Oaks 66/16 kV Substation	14	5	6	Tier 3
8	Construct a New 16kV Circuit at Gonzales 66/16 kV Substation	15	3	14	Tier 3
9	Rebuild Elizabeth Lake-Pitchgen 66 kV Subtransmission Line	12	8	5	Tier 1
10	Alberhill System Project: Construct a New 500/115 kV Substation and construct New 115 kV Subtransmission Lines[2,3]	6	12	8 (FLAG)	Tier 3
11	Install a New Capacitor at Channel Island 66/16 kV Substation	17	10	9	Tier 3
12	Install a New Transformer at Mira Loma 66/12 kV Substation	11	13	4	Tier 2
13	Install a New 12 kV Circuit at Chase 66/12 kV Substation	9	11	13	Tier 2
14	Install a New Capacitor at Devers 220/115 kV Substation	16	7	15	Tier 3
15	Upgrade Transformer and Construct a New 12 kV Circuit at Valley 115/12 kV Substation	13	15	10	Tier 3
16	Cal City Project: Construct a New 115/12 kV Substation and Construct New 115 kV Subtransmission Lines[1]	3		17	Tier 2
17	Del Valle Project: Construct a New 66/16 kV Substation and Construct New 16 kV Circuits[1]	4		16	Tier 2

[1] Pre-Application Projects; The 2020 May Ruling requires the Forecast Certainty metric to be excluded from the prioritization for Pre-Application Projects
[2] Post-Application Project
[3] In 2022, projects were flagged if islanding would be required to meet the same level of reliability/resiliency as the wires solution

Tiering vs Ranking

- Project tier is a function of both the quartile-based RAG score (quantitative) and Flag status (qualitative).
- Project ranking is determined by project score (quantitative) only.

Metric Ranking	RAG Score
Red Flag	Tier 3
Bottom Quartile	-1
Second/Third Quartile	0
Top Quartile	+1
Excluded	N/A

Total RAG Score	Project Tier
Tier 3	Tier 3
< 0	Tier 3
= 0	Tier 2
> 0	Tier 1

Figure 5-3: Initial SCE Recommendations for RFO and Pilot Procurement

Tier	Substation/ Subtransmission Line	Project Description	DER Need Location	Distribution Service Required	Operating Date	Cost Estimate	Max 10-year Capacity Need (MW)	Max 10-year Energy Need (MWh)
Partnership Pilot								
Tier 1	Saugus-Haskell 66 kV	Rebuild Saugus-Haskell 66 kV Subtransmission Line	Haskell 66/16 kV	Reliability, Capacity	6/1/2026	$9.14M	4.00	8.10
Tier 1	Mesa-Narrows 66 kV	Rebuild Mesa-Narrows 66kV Subtransmission Line[1]	Narrows 66/12 kV	Reliability, Capacity	6/1/2025	$3.83M	1.10	2.00
Tier 2	Mira Loma 66/12 kV	Install a New Transformer at Mira Loma 66/12 kV Substation[1]	Mira Loma 66/12 kV	Capacity	6/1/2025	$3.96M	7.70	25.60
Tier 3	North Oaks 66/16 kV	Upgrade Transformers at North Oaks 66/16 kV Substation	North Oaks 66/16 kV	Capacity	6/1/2025	$3.92M	21.1	107.2
Standard Offer Contract Pilot								
Tier 1	Alessandro 115/33 kV	Install a New Transformer at Alessandro 115/33 kV Substation	Alessandro 115/33 kV	Capacity	6/1/2025	$1.58M	1.30	2.20
DIDF RFO								
Tier 1	Triton 115/12 kV	Install a New 12kV Circuit at Triton 115/12 kV Substation	Seawolf 12 kV	Capacity	6/1/2026	$3.00M	3.72	16.90
Currently Not Recommended for Solicitation								
Tier 1	Santa Clara-Colonia 66 kV	Rebuild Santa Clara-Colonia 66 kV Subtransmission Line	Colonia 66/16 kV	Reliability, Capacity	6/1/2025	$25.89M	32.70	342.70
Tier 1	Elizabeth Lake-Pitchgen 66 kV	Rebuild Elizabeth Lake-Pitchgen 66 kV Subtransmission Line	Elizabeth Lake 66/16 kV	Reliability, Capacity	6/1/2026	$6.51M	13.2	66.00

[1] SCE is tentatively recommending this project for the Partnership Pilot pending further studies on whether existing IOU-owned DER solutions at this site will be able to meet the need for this project. A final determination will be made before the 11/15 AL requesting approval to launch the Partnership Pilot.

Energy for What's Ahead℠

Background Review of Tiering and Ranking

In this DIDF cycle SCE's DDOR has a total of 17 CDOs, thus rankings for each metric in the prioritization workbook run from 1 to 17 (fewer if there are identical scores). If there are 17 different ranks for each metric the rankings and color coding are as follows:

- A project gets a Green color if it is ranked 1-5 (5 possible projects can be Green).
- A project gets a Yellow color if it is ranked 6-13 (8 possible projects can be Yellow).
- A project gets a Red color if it is ranked 14-17 (4 possible projects can Red).

For a project to be placed into Tier 1 automatically by the workbook it must have a net Red Amber Green (RAG) score of +1 or more. This can be achieved if it has:

- One Green and no Reds
- Two Greens and up to one Red
- Three Greens

Given that background, the IPE reviewed SCE's Candidate Deferral Project Opportunities that were not already slated for procurement in a PP or SOC Pilot or an RFO.

Basic approach taken for the review was to:

First examine the definition, threshold values and application of Flags since projects that are Flagged are placed into Tier 3 automatically by SCE. We found that SCE used a Flag for only one project (Alberhill) which we found reasonable application of the Flag. We do not view the application of the Red Flag on this project as having an effect on the overall outcome of the prioritization process.

Next, we examined projects that were not recommended for procurement using a sensitivity analysis of a project's CE score. Under this approach the initial emphasis is placed on projects that ranked relatively high in Cost Effectiveness (CE) but were not high enough to be in the first quartile for CE but had good (yellow) rankings in Forecast Certainty (FC) and Market Assessment (MA).

Sensitivity analysis calculates how much the deferral/capital cost of a project would have to be increased in order for the project to receive a CE rank of that would put it into the first quartile. (Shown in green in the Joint Prioritization Metrics Workbook (JPMW)). The calculation of these sensitivities is expressed as a multiplier (i.e., 1.5 times)

This sensitivity analysis was performed with Pre and Post Application Projects and those involved in procurement removed from the Workbook leaving 12 CDOs. Thus, the sensitivity analysis calculates how much the deferral/capital cost of a project would have to be increased in order for the project to receive a CE rank of three (and thus be in Quartile 1). Note that the Tiering results with the four projects removed were similar to original JPMW). The results of the sensitivity analysis are summarized in the IPE SCE DPAG Report published in November 2022 and the core recommendations were reviewed with the DPAG. In summary the IPE found that one more project, the ”Install Rector-Review No. 2 66kV Subtransmission” which was ranked as Tier 2 project should be considered for procurement because of its strong Cost-Effectiveness metrics. The IPE found that the remaining results of the prioritization process were reasonable.

Next emphasis was looking at projects that were close to a good CE score (Quartile 1) that may have had a poor FC or MA ranking (Quartile 4).

5.2. Review of Final Prioritization and Ranking

As noted earlier, SCE’s final GNA/DDOR Report included additional candidate deferral opportunity projects. The IPE reviewed the prioritization of those additional CDOs and notes the following:

- The Tier 2 project that was recommended by the IPE for procurement in the review of the initial SCE ranking (discussed in Section 5.1) is now a Tier 1 and recommended for procurement. We support that recommendation.
- Of the nine newly identified candidate deferral projects in their final result filed on January 13, 2023 two projects ranked in Tier 1, three in Tier 2, and four in Tier 3.
- We reviewed these nine projects and found that two projects were recommended for procurement and the other 7 were not. We support the recommendation that the two projects should proceed to procurement.
- We reviewed the seven new CDOs not recommended for procurement and found the following:
    - The Install a New Circuit at Elizabeth Lake which is a Tier 2 project does not have a strong CE score and has a relatively low MA score and is not recommended for procurement.
    - The following projects have low to very low CE scores and are not recommended for procurement
        - Reconfigure Browning - Delano 66 kV Subtransmission Line
        - Install a New 12 kV Circuit at Bloomington 66/12 kV Substation
        - Increase Sunnyside 66/12 KV Substation by Eliminating Limiting Components
        - Install a New 16 kV Circuit at Saugus 66/16 kV Substation
        - Install a New 12 kV Circuit at Talbert 66/12 kV Substation
        - Install a New 12 kV Circuit at Bain 66/12 kV Substation

6. Other Items of Interest

6.1. Miscellaneous – Observations, Conclusions and Recommendations

Transportation Known Loads

- The IPE observes that known loads because they are tied to specific locations on the distribution grid and tied to customer requests for additional service are a reasonably accurate way of "disaggregating" load growth. In addition, in the case of EV commercial charging stations which are captured as known loads, these known loads are also a reasonably accurate way of disaggregating a portion of DER growth, namely commercial charger growth. While this source of load and DER load growth (known load information driven by customer requests) has its own set of issues/uncertainties it appears that is provides highly valuable information to the distribution planning process.
- The IPE observes that transportation-related known loads (primarily, EV charging stations) have increased in the current planning cycle when compared to the last cycle, albeit by a small amount as noted above. With California's goal of 100% zero-emission vehicle by 2035, it can be reasonably expected that the transportation-related loads will increase in the near future. It is not only important for the utilities to know the location, timing and peak load impact of these new loads, but also have this information as far in advance as possible to make sure any grid needs are addressed in a timely manner in order to support California's zero-emissions goal. It is important for utilities consider is known load project identification business processes to see where improvements might be achievable to ensure that California's environmental goals are fully supported by identifying grid needs that need to be addressed as far out in the futures as required. This would include for example, to engage with charging station developers and fleet operators to have the most up-to-date information reflected in their distribution plans. The IPE reviews how the utilities currently develop their known loads for transportation electrification and reports its the findings in the Post-DPAG report to be distributed in March 2023.

Pilot Selection

- The IPE compares the methodology used by all three utilities for the Standard-Offer-Contract pilot and Partnership Pilot project selection in the post-DPAG report to be distributed in March 2023.

Load Forecasting Comparison

- In the 2020 IPE Report we recommended that a comparison be made (Step 19 of the IPE Plan) of 2020 forecasts (included in the 2020 DIDF) and 2020 actuals (both on a 1-in-10-year basis) at the circuit level for 2020 for a statistically meaningful number of circuits. This is a repeat of the process used in the previous cycle (also Step 19) except in that in the previous cycle the circuits analyzed were just those associated with the Candidate Deferral Projects. Note that the verification of the comparison for SCE is included in Section 7.4.5.

- We believe that insight was gained through this review for all of three utilities and we recommend that it be included in future IPE validation and verification processes to get an overall view of the accuracy of the DIDF load forecasting process.

Redaction of Data in Public Version of the IPE DPAG Report

- SCE has indicated that it has limited the data that it has declared confidential to data for circuits that meet the CPUC 15/15 rule. This should minimize the need to redact information in the body of the IPE Report as well as in the many documents included in Appendices. This should allow stakeholders to fully understand this report, as a result of not having to guess the implication of information that has been redacted.

Resiliency Projects

- We observed that there was some confusion regarding the definition and application of Resiliency Service at the DPAG meetings – one of the four services within the DIDF. The IPE reviews the approaches used by the three IOUs in identifying and solving resiliency needs in the Post-DPAG report to be distributed in March 2023. Based on this review, recommendations regarding the inclusion of resiliency needs in the GNA/DDOR, revisions to the definition of resiliency if included in the GNA/DDOR and the types of resiliency projects that are deferrable will be made.

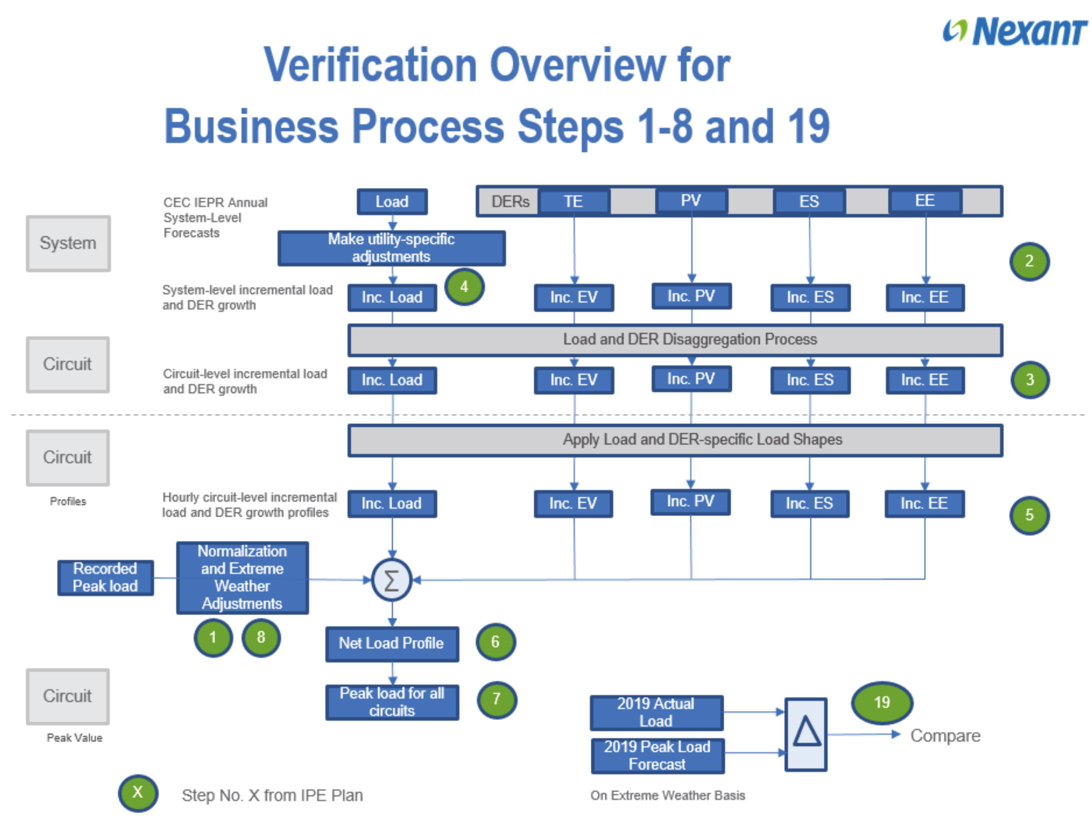
Known Load Tracking

- The ALJ’s June 16, 2022 DIDF Reform order required all three IOUs to track known load projects in the 2022 GNA/DDOR. The reform also required the known load tracking dataset to include a unique project identifier, impacted circuit, initial service request date, load amount, current expected in-service date or indication if service request was cancelled, if appropriate, and type/category of load and, if appropriate, the actual date service was initially provided and the amount. SCE provided this data as Appendix E of their GNA/DDOR report.
- The IPE reviewed the data sent by the three IOUs and found that there were various interpretations of the request and different approaches to provide the data. The IPE recommended that a set of definitions be used by all three utilities. The IPE has followed up with all three utilities and the Energy Division to better understand the data that is being provided and to ensure that the data will be able to be used to perform the tracking analysis envisioned in the ALJ’s June 16th reform order. The IPE reports on this effort in the Post-DPAG report.

7. Verification Approach and Results

In this section we will discuss the verification approach used and the results achieved for the steps identified in the IPE Pan. This verification review will follow the framework set out in the Final IPE Plan included in Appendix C. The following graphic provides an overview of the Steps 1 through 8 and 19 in the review process. Note: the graphic does not reflect that there is an impact from SCE's TOU Metering which is included in the forecast business process but not in the graphic.

Figure 7-1: Business Steps Overview



7.1. PROCESSES TO DEVELOP SYSTEM LEVEL FORECASTS AND DISSAGREGATE TO CIRCUIT LEVEL

7.1.1. Collect 2021 Actual Circuit Loading, Normalize and Adjust for Extreme Weather – Steps 1 and 8

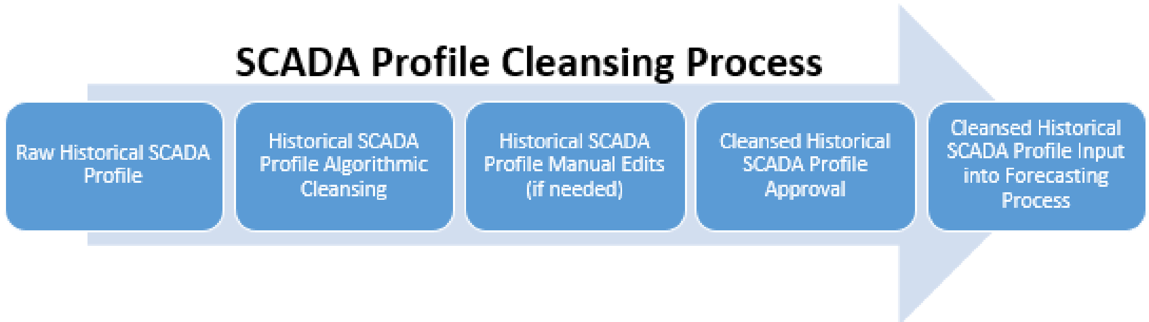
This step reviews the process that SCE uses to develop the starting point of the forecasting process which includes collecting actual circuit loading profile data (normally using SCADA), normalize it to an average year (referred to as a 1 in 2 value) and adjusting it to an extreme weather year (referring to a 1 in 10 year).

SCE refers to this process in three steps – 1) SCADA Input, 2) Forecasting, and 3) Output of starting point, normal, and extreme values.

In Step 1, SCE collects hourly SCADA data and then uses a sophisticated “cleansing” software system to detect and remove/replace “bad” data. The cleansing process detects a number of situations including, for example, missing data and periods of time where the data is indicative of non-normal switching of the circuit due to planned or unplanned work. These situations introduce inaccuracies into the data collected and once they are detected can be corrected. The modification performed by the automated cleansing algorithm are assessed by planning engineers and a manual edit is performed where necessary before the historical loading profiles are used in the forecasting process.

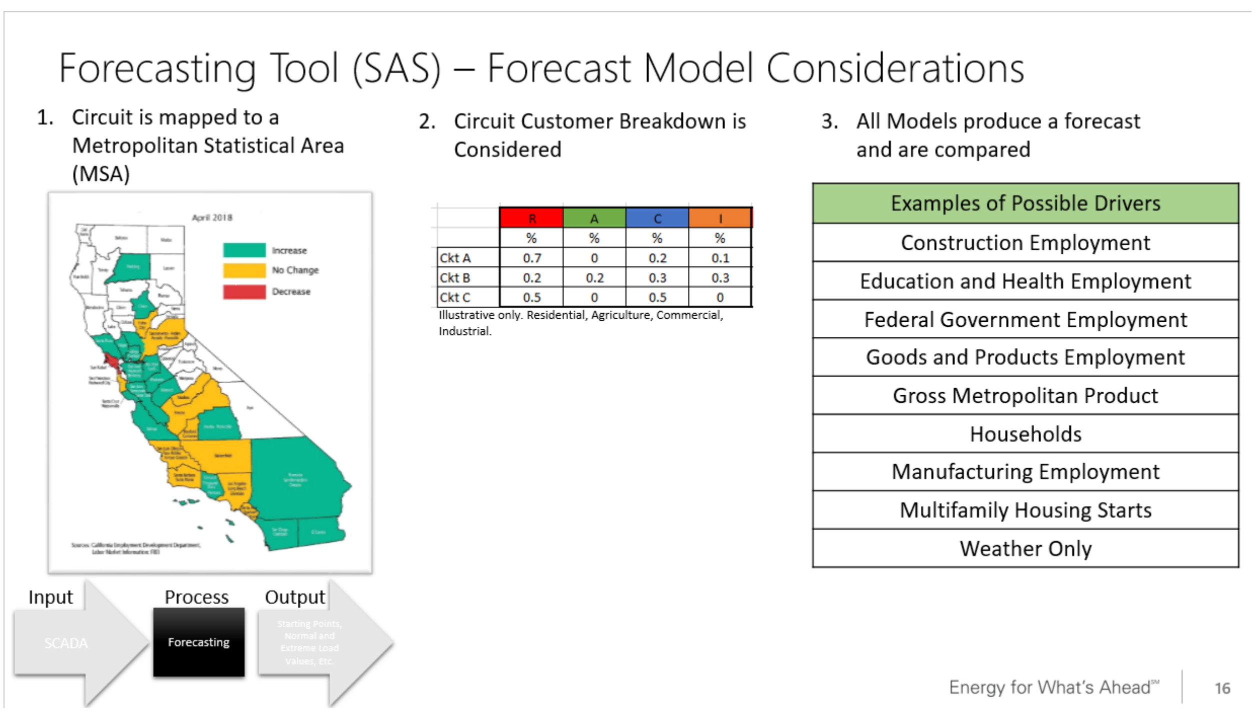
SCE is in the process of converting to a new set of software to support its planning processes that moves from a point-based approach to a profile approach. This applies to its “cleansing” software (referred to as Re|Grid) which operates on profile data. Under this approach peak loading days are not selected; normalization is done in forecasting and cleansing is applied to 8,760 profiles and not to a peak day. Thorough cleansing of 8,760 type profile data is important since SCE uses an energy-based approach (which is impacted by all hours of the day and not just the peak hours) at this point in the load forecasting process. A process within forecasting calculates the asset peak date and time of the normalized profile of the most recent year, which is utilized in the legacy planning system while the new profile-based software planning system is being built.

Figure 7-2: Cleansing Process



The next step in the process, referred to as Forecasting, is performed in SAS (a software analysis tool). The SAS tool uses statistical methods to generate a Forecasted Profile. Figure 7-3 shows the overall SAS process. Linear regression is used to determine the Forecast Driver that correlates the best to the actual values in the period studied.

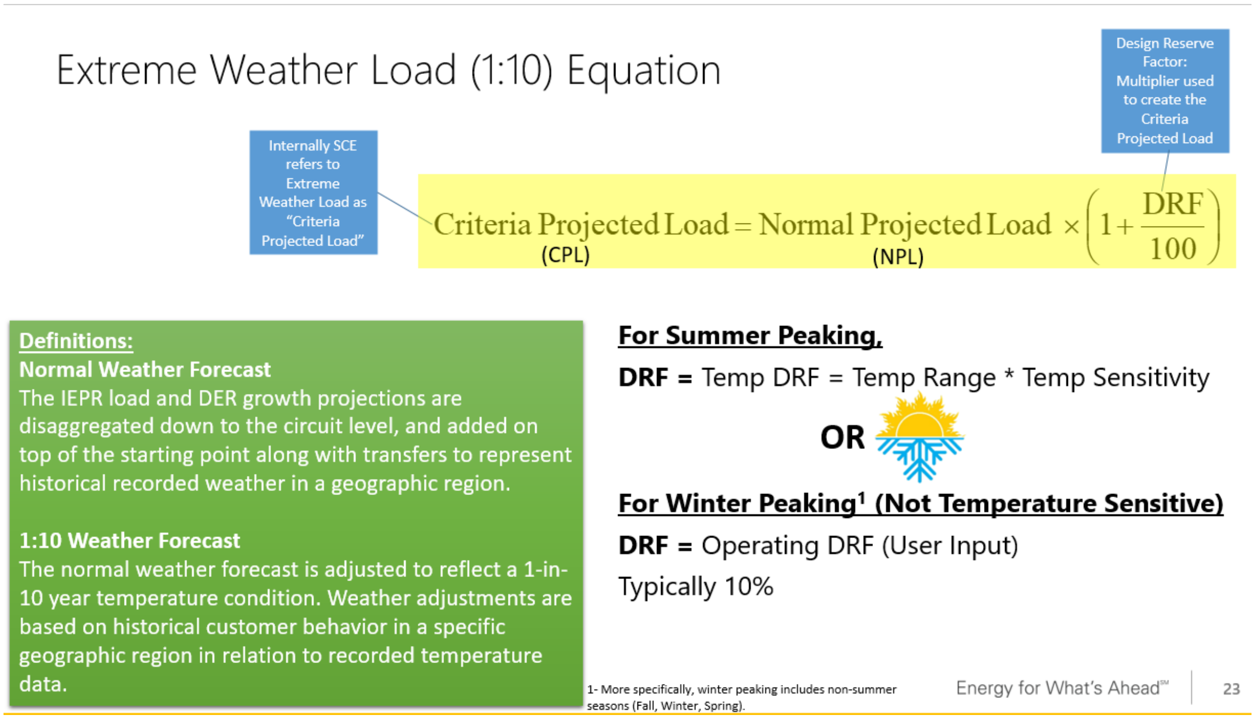
Figure 7-3: Overall SAS Process



SCE uses a Typical Meteorological Year (TMY) based methodology to generate normalized (1-in-2) temperature data to be used for forecasting future load in forecasting models. Actual historical weather is used to determine which month is the closest to the 50th Percentile. That month from that year is used in the TMY as the normal weather which is used to develop 1 in 2 profiles. These loads are referred to as Normal Projected Load.

SCE calculates 1 in 10 load values referred to as Critical Projected Load using a formula shown graphically in Figure 7-4.

Figure 7-4: Critical Projected Load Adjustment

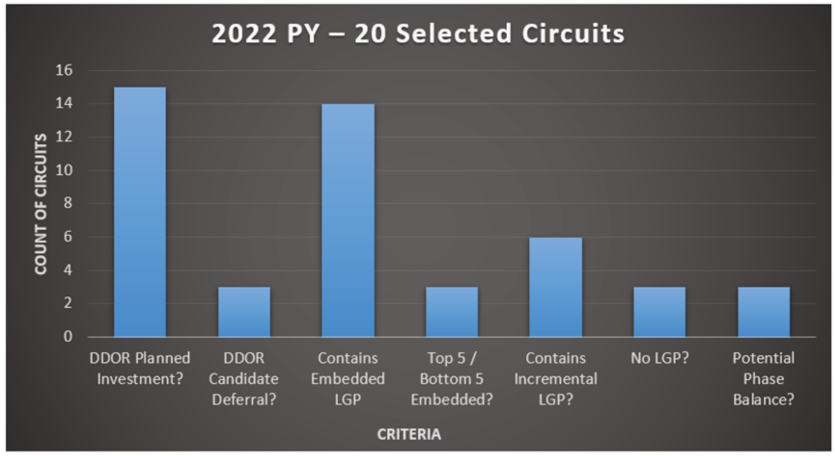


We can see from the graphic that the adjustment is a function of the Design Reserve Factor (DRF), which is a function of location in the SCE system. The location of an asset influences the DRF since the temperature used in calculating the DRF comes from the closest weather station or best geographical representation of the asset.

As part of the IPE verification process, working with SCE, the IPE selected 20 circuits to be used as appropriate for various steps in the review process. The circuits and their characteristics (whether they were associated with planned investment, were candidate deferral projects, included embedded or incremental known load adjustments, etc.) are tabulated in Figure 7 5 below. The objective was to choose a subset of circuits that could be used in the verification of many of the IPE defined business steps.

Figure 7-5: 20 Selected Circuits for use in IPE Verification

Substation	Circuit	Region
Victoria 66/16	Addis	Metro West Region
Colonia 66/16	Broome	North Coast Region
Roadway 115/12	Caterpillar	Rurals Region
Bunker 115/12	Chaney	San Jacinto Valley Region
Oak Grove 66/12	Clancy	San Joaquin Region
Auld 115/12	Colt	San Jacinto Valley Region
Carolina 66/12	Connecticut	Orange Region
Milliken 66/12	Cuervo	Metro East Region
Mayberry 115/12	Dartmouth	San Jacinto Valley Region
Woodruff 12/4.16	Ferina	Metro West Region
Isabella 66/12	Flycatcher	San Joaquin Region
Gisler 66/12	Klingon	Orange Region
Colonia 66/16	Mugu	North Coast Region
Garnet 115/33	Palmview	Desert Region
Hi Desert 115/33	Pinto	Rurals Region
Downs 115/12	Rocket Town	Rurals Region
Corona 66/12	Serfas	Metro East Region
Bullis 66/4.16	Tucker	Metro West Region
Peyton 66/12	Tupelo	Metro East Region
Bloomington 66/12	Wigwag	Desert Region



The embedded "SCE Regions Map" file is an illustrative representation of SCE's regions across its service territory. This attachment is subject to geographical boundaries realignment and is intended for generality only.

SCE Regions Map

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7.1.2. Determine Load and DER Annual Growth on System Level - Step 2

This step reviews the development of utility specific system level values of load and DER growth from the CEC IEPR data. In the case of SCE these values are energy values, since SCE uses system level energy values at this part of the overall planning process. Shown in Figure 7-5 and Figure 7-6 are the CEC data sets and scenarios used by SCE in this step and a comparison of what was used in 2022 to what was used in 2021. All three utilities used a set of data and scenarios for their companies that correspond to the set SCE used. These data sets and scenarios were presented to the Distribution Forecast Working Group.

Figure 7-6: CEC IEPR Scenarios for 2021 GNA/DDOR Filings as Approved by Energy Division

		2021 GNA/DDOR (Plan Year 2021)	2022 GNA/DDOR (Plan Year 2022)
		SCE	**SCE**
	IEPR Vintage	2019 IEPR	2020 IEPR Update
Scenario	Solar PV	Mid-Mid	Mid-Mid
	Energy Storage	Mid-Mid	Mid-Mid
	Electric Vehicles (TE)	Mid-Mid	High TE
	Non-LDV EV (TE)	Mid-Mid	High TE
	Energy Efficiency	Mid-Low	Mid-Low[1]
	Load Modifying DR	Mid-Mid	Mid-Mid[1]
	Load	Mid-Mid	Mid-Mid
	Time of Use	Mid-Mid	Mid-Mid[1]

Figure 7-7: CEC IEPR Data Sets used by SCE in 2021 and Disaggregation Differences

DER/Load	2021 Methodology	2022 Methodology
Solar PV	• Used 2019 IEPR and converts from TAC to Retail level	• Uses 2020 IEPR Update and converts from TAC to Retail level
Energy Storage	• Used 2019 IEPR and converts from TAC to Retail level	• Uses 2020 IEPR Update and converts from TAC to Retail level
Electric Vehicles (TE)	• Used 2019 IEPR and converts from TAC to Retail level	• Uses 2020 IEPR Update and converts from TAC to Retail level
Non LD-EV (TE)	• Used 2019 IEPR and converts from TAC to Retail level • Transportation Refrigeration Units (TRU) were added to the list of disaggregated Non-LDV sectors. TRU utilized ICF load shapes and utilized CARB's list of facilities.	• Uses 2020 IEPR Update and converts from TAC to Retail level
EE	• Used 2019 IEPR and converts from TAC to Retail level	• Uses 2019 IEPR and converts from TAC to Retail level
LMDR	• Used 2019 IEPR and converts from TAC to Retail level	• Uses 2019 IEPR and converts from TAC to Retail level
TOU	• Used 2019 IEPR and converts from TAC to Retail level	• Uses 2019 IEPR and converts from TAC to Retail level
Load	• Used 2019 IEPR • Load WDAT's and customer substations are also considered as incremental in addition to 2020 planning cycle categories. These two were included in the 2020 planning cycle but was not specifically called out in the V/V.	• Uses 2020 IEPR Update

The Excel spreadsheet in Figure 7-8 shows how SCE used CEC IPER data to develop system level load energy growth, for use in developing annual energy delivered over its distribution system, which is then used in the distribution planning process.

Figure 7-8: Process to Develop System Load Growth

Process to obtain IEPR Load Growth for Use in the 2022 DSP

Start with IEPR Forms

Step	SCE IEPR Load (MWh)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Source
1	Total Consumption (includes TE and Climate Change)	106,200,768	108,987,309	##########	112,050,826	113,214,752	114,255,344	115,361,677	116,470,877	117,585,516	118,652,353	2020 IEPR: SCE Load Modifiers (line 24)
2	TE Forecast (Mid)	2,548,062	3,140,969	3,655,317	4,134,112	4,526,701	4,891,419	5,268,527	5,638,233	6,020,131	6,441,106	TE Forecast (Mid Scenario Line 4)
3	Total Consumption (without EV)	103,652,707	105,846,340	##########	107,916,714	108,688,051	109,363,925	110,093,150	110,832,644	111,565,385	112,211,247	Calculation (Step 1 minus Step 2)
4	**Inc. Growth (MWh)**	1,620,509	2,193,633	1,213,236	857,138	771,337	675,874	729,225	739,494	732,741	645,862	Calculation (Annual Incremental of Step 3)

Remove growth in areas not part of the Distribution Substation Plan

Step	Other Growth (MWh)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Source
5	Anaheim, City of	2,233,329	2,275,921	2,286,461	2,286,223	2,283,291	2,279,599	2,280,057	2,282,475	2,286,027	2,289,586	2020 IEPR: Form 1.5a (Line 37)
6	Pasadena Water and Power	991,627	1,010,538	1,015,218	1,015,113	1,013,811	1,012,171	1,012,375	1,013,448	1,015,026	1,016,606	2020 IEPR: Form 1.5a (Line 38)
7	Riverside, City of	2,102,092	2,142,182	2,152,102	2,151,879	2,149,118	2,145,643	2,146,074	2,148,350	2,151,694	2,155,043	2020 IEPR: Form 1.5a (Line 39)
8	Vernon, City of	1,260,118	1,280,466	1,285,501	1,285,387	1,283,987	1,282,222	1,282,442	1,283,597	1,285,294	1,286,993	2020 IEPR: Form 1.5a (Line 40)
9	MWD - LA Basin	202,618	202,618	202,618	202,618	202,618	202,618	202,618	202,618	202,618	202,618	2020 IEPR: Form 1.5a (Line 42)
10	CDWR - Big Creek/Ventura	3,311,005	3,311,005	3,311,005	3,311,005	3,311,005	3,311,005	3,311,005	3,311,005	3,311,005	3,311,005	2020 IEPR: Form 1.5a (Line 45)
11	CDWR - Other	584,729	584,729	584,729	584,729	584,729	584,729	584,729	584,729	584,729	584,729	2020 IEPR: Form 1.5a (Line 49)
12	MWD - Other	1,720,428	1,720,428	1,720,428	1,720,428	1,720,428	1,720,428	1,720,428	1,720,428	1,720,428	1,720,428	2020 IEPR: Form 1.5a (Line 50)
13	**Total**	12,405,946	12,527,887	12,558,062	12,557,382	12,548,986	12,538,415	12,539,727	12,546,649	12,556,821	12,567,008	Calculation (Sum of Step 5 thru Step 12)
14	**Incremental Other Growth (MWh)**	75,325	121,941	30,175	(680)	(8,395)	(10,572)	1,313	6,922	10,172	10,187	Calculation (Annual Incremental of Step 13)

Final incremental load growth values for the DSP at SCE system Level

Step	Results (MWh)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Source
16	**SCE System Total Consumption (MWh)**	91,246,761	93,318,453	94,501,514	95,359,332	96,139,064	96,825,510	97,553,422	98,285,995	99,008,564	99,644,239	Calculation (Step 3 minus 13)
17	**SCE System Load Growth (Inc.)**	1,545,184	2,071,692	1,183,061	857,818	779,732	686,446	727,912	732,572	722,569	635,675	Calculation (Annual Incremental of 16)

The notes at the right of the table provide detail about the spreadsheet calculations. The data at the top of the table is reduced by the load not served by SCE (shown in the middle of the table) and a net annual energy growth in MWh is calculated and shown on line 17.

Similar calculations were performed to develop annual energy growth at the system level based upon CEC IEPR data for Energy Efficiency (EE), Transportation Electrification, Photovoltaics (PV), Energy Storage (ES), Load Modifying Demand Response, and Residential Time of Use (TOU)[6]. An example of the results of those calculations are shown in Figure 7-9.

Figure 7-9: System Level Growth for EE

2019 CEC IEPR EE System Forecast	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Cumulative EE Forecast (MWh) TAC	400,672	717,880	998,955	1,296,146	1,584,937	1,862,614	2,109,522	2,347,398	2,581,313	2,812,510	3,044,386	3,295,379
Cumulative EE Forecast (MWh) Retail	365,828	655,510	912,027	1,183,076	1,446,592	1,700,032	1,925,420	2,142,579	2,356,078	2,567,068	2,778,655	3,007,681
Annual Incremental EE Forecast (MWh) Retail	365,828	289,683	256,517	271,049	263,515	253,441	225,387	217,159	213,499	210,990	211,587	229,026
SCE TAC to Retail Conversion Factor	1.095	1.095	1.095	1.096	1.096	1.096	1.096	1.096	1.096	1.096	1.096	1.096

These values are then used, along with the starting points, to develop a load forecast for load and DERs in subsequent process steps. The IPE verified the calculation and the fact these values were used in the disaggregation process as input in subsequent steps of the overall load forecasting process.

The IPE verified Step 2 as discussed above through a combination of demos performed by SCE and analysis performed by the IPE.

[6] Residential time of use captures the changes in energy use/growth due to the implementation of TOU meters.

7.1.3. Disaggregate Load and DER Annual Growth to the Circuit Level – Step 3

In Step 3 and 3a, the system level values of load and DER growth are disaggregated to the circuit level and then a check is performed to determine how the sum of the circuit values compare to the system level values reviewed in Step 2. This check is performed for load and all DERs listed earlier. An example of this check is shown below in Figure 7-10 for annual load growth. The system level values on the third line are compared to the sum of the circuit level values (after disaggregation) on the fourth line, and a percent difference is calculated on the fifth line. We see that the difference is 0.0% difference in all years. A check is also made to make certain that the value on line three (1,545,184) in this table is the same as line 17 in Figure 7-8.

Figure 7-10: Check of System Level Load Growth vs. Sum of All Circuit Load Growth

Load Disaggregation (System vs. Circuit)

Comparison of System Forecasted Values to Aggregate of Disaggregated Circuit Values

Description	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
IEPR System Level Total (MWh)	1,545,183.85	2,071,692.14	1,183,061.07	857,818.09	779,732.19	686,445.67	727,912.31	732,572.38	722,569.28	635,675.40
Total Disaggregated at Circuit Level (MWh)	1,545,183.85	2,071,692.14	1,183,061.07	857,818.09	779,732.19	686,445.67	727,912.31	732,572.38	722,569.28	635,675.40
Amount Difference (MWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Percentage Difference	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

The IPE verified Steps 3 and 3a through a combination of demos performed by SCE and analysis performed by the IPE.

7.1.4. Add Incremental Load Growth Projects to Circuit Level Forecasts (those loads not in CEC forecast) – Step 4

This step reviews the addition of LGPs that represent load over and above the load in the CEC IEPR. The loads included in 2022 which are referred to as Incremental Load Growth Projects are discussed in Section 2.2.

We can see from the figure below (table on the left side) that 6 of the 20 selected circuits have Incremental LGPs. The LGP MW amount is shown below for these circuits in the lower right of the figure,

Figure 7-11: Selected Circuits with a Load Growth Project

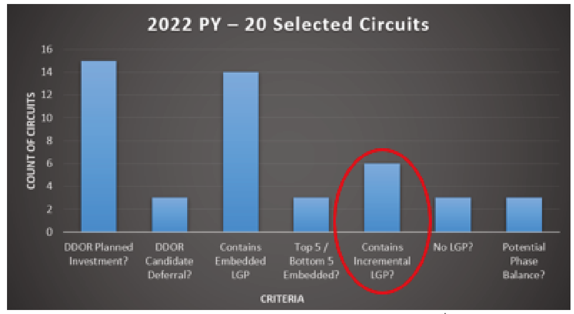
Circuits containing Incremental LGPs

Highlighted circuits represent those from list of 20 containing incremental LGPs

Substation	Circuit
Victoria 66/16	Addis
Colonia 66/16	Broome
Roadway 115/12	Caterpillar
Bunker 115/12	Chaney
Oak Grove 66/12	Clancy
Auld 115/12	Colt
Carolina 66/12	Connecticut
Milliken 66/12	Cuervo
Mayberry 115/12	Dartmouth
Woodruff 12/4.16	Ferina
Isabella 66/12	Flycatcher
Gisler 66/12	Klingon
Colonia 66/16	Mugu
Garnet 115/33	Palmview
Hi Desert 115/33	Pinto
Downs 115/12	Rocket Town
Corona 66/12	Serfas
Bullis 66/4.16	Tucker
Peyton 66/12	Tupelo
Bloomington 66/12	Wigwag

- Connecticut 12 kV 1-2-3 example can be applied in the same manner to other circuits containing incremental LGPs for every year of the 10 year forecast period

Incremental LGP data provided during IPE Business Process Step 1 captures Incremental Growth Application Before Shapes (MW) on highlighted circuits



Previously provided circuit selection graph showing incremental LGP circuit count

	Incremental Growth by Year									
Circuit Name	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Addis	0.950	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Caterpillar	4.535	1.400	1.080	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Connecticut	1.625	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Chaney	0.000	0.600	0.600	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Klingon	1.941	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Palmview	16.000	18.500	44.000	32.000	43.000	0.000	5.000	0.000	0.000	0.000

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The IPE verified Step 4 through a demo of the addition of the LGP on the Connecticut circuit performed by SCE and analysis performed by the IPE.

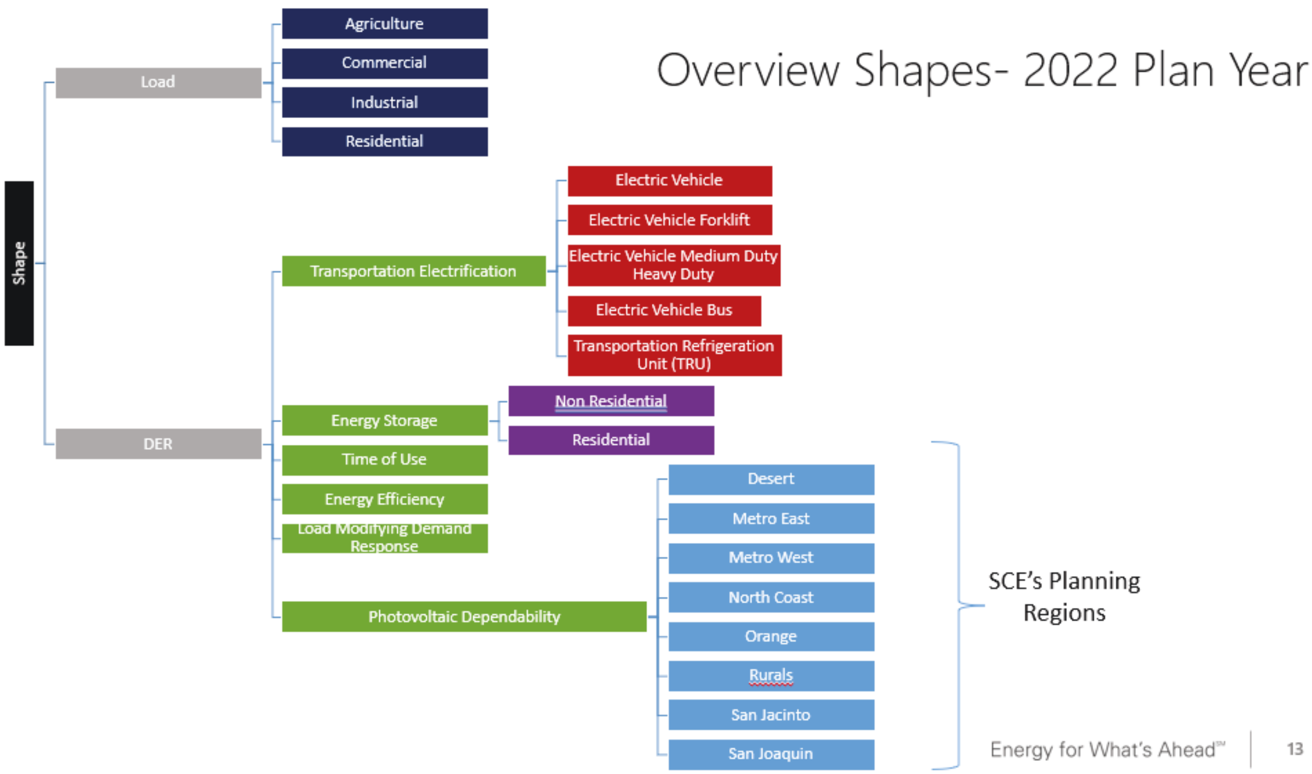
7.1.5. Convert Peak Growth to 8760 Profile, Determine Net Load and Peak Load – Steps 5, 6, and 7

This section will review the process used to convert the data from the previous step into profiles, combine the load and DER profiles, to develop a net-load profile and to calculate a net peak load for the circuit.

SCE uses shapes to disaggregate energy estimates into hourly energy estimates. SCE's shapes are static array of data points used as a variable to represent the variation in (typically hourly) energy consumption dependent on the technology, sector, season, etc. and are usually on a time basis of 8760 hourly data points over the course of a year. SCE uses shape arrays for all components of net load – i.e., customer consumption, PV, EE, DR EC etc.

Figure 7-12 graphically represents the shapes that SCE uses in the disaggregation process.

Figure 7-12: Disaggregation Shapes



Figures 7-13 and 7-14 are SCE's demonstration of the use of shapes for the Connecticut circuit. Figure 7-13 shows the shapes and how they combine, and Figure 7-14 shows the workbook that can be used to demo the application of shapes for all 20 selected circuits for Steps 2, 3, 3a, 4, 5, 6 and 7.

Figure 7-13: Shapes Applied to Develop Net Load for Connecticut

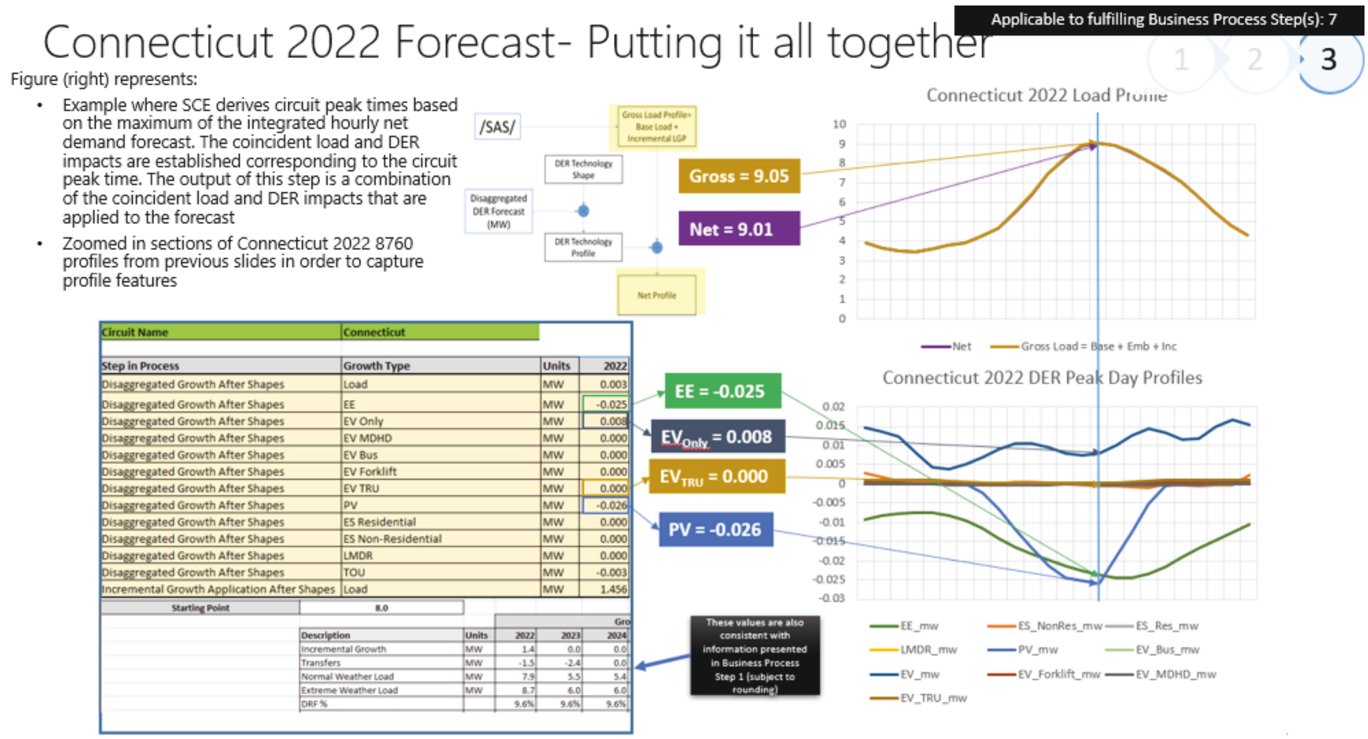


Figure 7-14: Workbook Demo of Connecticut – Steps 5-7

Steps: 2, 3, 3a

Step: 4

Steps: 5-7

Step: 4

Circuit Name	Connecticut											
			Incremental Growth by Year									
Step in Process	Growth Type	Units	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Disaggregated Growth Before Shapes	Load	MWh	10.941	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Disaggregated Growth Before Shapes	EE	MWh	106.607	106.128	106.022	101.552	85.184	80.364	76.964	74.057	73.477	79.082
Disaggregated Growth Before Shapes	EV Only	MWh	92.046	94.971	86.837	79.527	59.732	50.751	48.962	47.955	47.938	50.776
Disaggregated Growth Before Shapes	EV MDHD	MWh	0.149	0.384	0.286	0.408	0.527	0.629	0.712	0.719	0.723	0.853
Disaggregated Growth Before Shapes	EV Bus	MWh	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Disaggregated Growth Before Shapes	EV Forklift	MWh	1.536	1.429	1.357	1.275	1.318	1.425	1.543	1.589	1.656	1.771
Disaggregated Growth Before Shapes	EV TRU	MWh	6.113	6.255	6.784	6.966	1.101	1.157	1.033	1.025	1.038	1.060
Disaggregated Growth Before Shapes	PV	MWh	0.076	0.084	0.089	0.095	0.099	0.103	0.108	0.112	0.117	0.126
Disaggregated Growth Before Shapes	ES Residential	MWh	0.001	0.001	0.002	0.002	0.003	0.003	0.004	0.004	0.005	0.006
Disaggregated Growth Before Shapes	ES Non-Residential	MWh	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.016
Disaggregated Growth Before Shapes	LMDR	MWh	0.901	0.938	0.940	0.941	0.943	0.945	0.947	0.948	0.948	0.948
Disaggregated Growth Before Shapes	TOU	MWh	4.880	0.128	0.010	0.060	0.061	0.060	0.060	0.060	0.058	0.058
Incremental Growth Application Before Shapes	Load	MW	1.625	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Disaggregated Growth After Shapes	Load	MW	0.003	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Disaggregated Growth After Shapes	EE	MW	-0.025	-0.024	-0.026	-0.026	-0.022	-0.019	-0.019	-0.019	-0.020	-0.021
Disaggregated Growth After Shapes	EV Only	MW	0.008	0.008	0.009	0.008	0.006	0.005	0.005	0.005	0.004	0.005
Disaggregated Growth After Shapes	EV MDHD	MW	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Disaggregated Growth After Shapes	EV Bus	MW	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Disaggregated Growth After Shapes	EV Forklift	MW	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Disaggregated Growth After Shapes	EV TRU	MW	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Disaggregated Growth After Shapes	PV	MW	-0.026	-0.029	-0.022	-0.024	-0.025	-0.035	-0.027	-0.028	-0.029	-0.032
Disaggregated Growth After Shapes	ES Residential	MW	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Disaggregated Growth After Shapes	ES Non-Residential	MW	0.000	0.000	-0.001	-0.001	0.000	0.000	0.000	0.000	0.000	0.000
Disaggregated Growth After Shapes	LMDR	MW	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Disaggregated Growth After Shapes	TOU	MW	-0.003	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Incremental Growth Application After Shapes	Load	MW	1.456	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Data references orange table above

			Cumulative Growth by Year									
Step in Process	Growth Type	Units	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Disaggregated Growth After Shapes	Load (Base+Inc+TOU)	MW	1.456	1.456	1.456	1.456	1.456	1.456	1.456	1.456	1.456	1.456
Disaggregated Growth After Shapes	EE	MW	-0.025	-0.049	-0.075	-0.101	-0.123	-0.142	-0.161	-0.180	-0.200	-0.221
Disaggregated Growth After Shapes	TE	MW	0.009	0.017	0.027	0.036	0.043	0.047	0.052	0.057	0.062	0.067
Disaggregated Growth After Shapes	PV	MW	-0.026	-0.055	-0.077	-0.101	-0.126	-0.161	-0.189	-0.217	-0.246	-0.278
Disaggregated Growth After Shapes	ES Total	MW	0.000	-0.001	-0.001	-0.002	-0.002	-0.003	-0.003	-0.004	-0.004	-0.005
Disaggregated Growth After Shapes	LMDR	MW	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
		Total	1.41	1.37	1.33	1.29	1.25	1.20	1.16	1.11	1.07	1.02

The IPE verified Steps 5, 6, and 7 through a combination of demos performed by SCE and follow up data review performed by the IPE

7.2. PROCESSES TO DETERMINE CIRCUIT NEEDS AND DEVELOP GNA

7.2.1. Initial Comparison to Equipment Ratings, Evaluate No Cost Solutions and Comparison to Equipment Ratings after No Cost Solutions – Steps 9, 10, and 11

This step reviews the initial comparison of loading against the rating of assets to determine if there is a forecast equipment overload during the planning period, the evaluation and implementation of no cost solutions, and the comparison of loading against ratings after no cost solutions.

A review of the process of comparing forecasted load to equipment ratings to determine if there is a project overload was performed for both before and after no cost solutions. SCE's distribution and subtransmission equipment/loading comparisons include:

- Thermal loading of overhead circuits under N-0 conditions (Capacity Service)
- Duct bank temperature driven by loading under N-0 conditions (Capacity Service)
- Voltage under N-0 conditions (Voltage Service)
- Reactive Power under N-0 conditions
- Thermal loading of overhead conductor under N-1 conditions (Reliability, Capacity)
- Underground thermal loading under N-1 conditions (Reliability, Capacity)
- Voltage under N-1 (Reliability, Voltage Service)

Many of these comparisons have a unique methodology to determine if equipment is forecasted to exceed its rating or if parameters, like voltage, are forecasted to exceed established minimum or maximum limits. All of these types of comparisons were demonstrated by SCE. A few of these comparisons are discussed below.

No Cost Solutions

SCE demonstrated a No Cost solution example that showed how a single load transfer addressed the potential for a duct temperature violation. Arlington 12 kV circuit's bank ducts were forecast to exceed their limit (duct temperature greater than 90 Degrees C) in 2025 (demonstrating Step 10). Following a load transfer of 0.91 MWs to the Profit 12 kV circuit (Step 10), the duct temperatures on the Arlington circuit were forecast to be lower than 90 Degrees C for the entire planning period (Step 11).

Methodology Used to Forecast Overloads - Underground Circuit Under N-0 Conditions

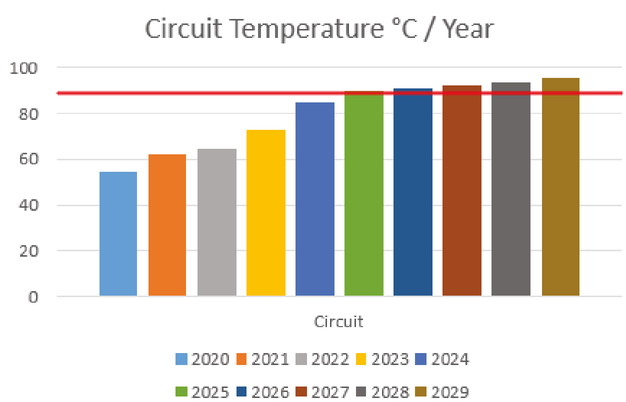
Using Figure 7-15, SCE demonstrated that an underground cable temperature violation can occur when there are no normal capacity violations. Further it describes how the amount of loading decrease is needed to reduce the forecast duct temperatures below the 90 Degree C limit. The slide indicates that an iterative duct bank temperature modeling calculation is used to iteratively reduce the highest loaded circuit within a duct bank until ALL circuits within the duct bank no longer show a duct temperature above 90 Degrees C. This methodology shows how effective thermal ratings for circuits are calculated under N-0 conditions for situations where a duct temperature violation is reached before a thermal capacity is reached.

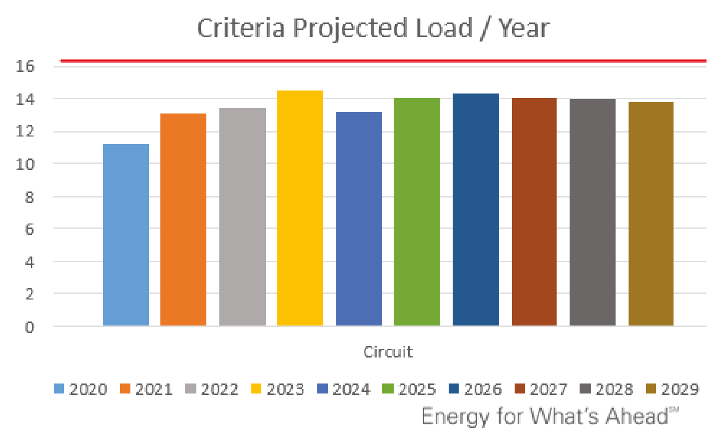
We can see from the bar chart in the figure that in 2026 one of the circuits in the duct bank is forecasted to exceed its 90 Degree C limit. That figure also demonstrates how in Figure 7-15 we see that initial bank temperatures for two segments of the Palace circuit are forecasted to exceed the temperature limit.

Figure 7-15: Underground Cable Calculations and Check Against Limits

- Deficiency: The amount of load reduction per circuit to mitigate temperature violations
  - A duct bank temperature modeling calculation is used to iteratively reduce the highest loaded circuit within a duct bank until ALL circuits within the duct bank no longer show an overloaded temperature.
- Rating: The load that corresponds to 90 degrees Celsius for that circuit

$$Rating[MVA] = \left(CPL_{year}\ of\ Circuit\ without\ project\right)[MVA] - \left(Load\ Reduction_{Year}\right)[MVA]$$





- Initial Duct Bank Temperatures

Circuit Names	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Adell	64.4	65.3	65.8	66.9	66.4	66.0	65.5	65.3	65.0	64.8
Palace	106.0	108.3	109.6	112.2	111.2	110.3	109.2	108.7	107.8	107.3
Adell	76.0	76.8	77.2	78.2	77.5	77.0	76.5	76.4	76.2	76.0
Palace	106.9	109.2	110.5	113.1	112.2	111.2	110.1	109.6	108.7	108.2

Step 9

- Duct Bank Temp Modeling Calculation: 2022

Duct	Substation	Circuit	Cable	Load Factor	Load Downstream (MVA)	Temperature
1-1						
1-2						
2-1	Chase 66/12 (D)	Adell	1000 MCM 15 KV-AL	0.68	1.1	64.4
2-2	Chase 66/12 (D)	Palace	1000 MCM 15 KV-AL	0.77	11.7	106.0
3-1	Chase 66/12 (D)	Adell	1000 MCM 15 KV-AL	0.68	6.7	76.0
3-2	Chase 66/12 (D)	Palace	1000 MCM 15 KV-AL	0.77	11.7	106.9

Convention:
x Row- y Col
Example: 3-2 is
3 Rows – 2 Columns

In Figure 7-16 we see that after the planned investment (DDOR_2022_ DSP34759_334554) is made and constructed (note operating date of 2025), the Palace temperatures are predicted to be below the temperature limit.

Figure 7-16: Final Cable Temperatures and GNA and DDOR Entries

- Loading Reduction / Deficiency (MVA)

Circuit Names	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Palace	1.39	1.54	1.65	1.85	2.11	2.28	2.35	2.35	2.30	2.26
Wyle	0.00	0.15	0.28	0.52	0.80	1.09	1.20	1.20	1.17	1.26

- Final Underground Cable Temperatures

Circuit Names	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Chase2025 New Circuit	N/A	N/A	N/A	55.5	56.7	58.0	58.5	58.6	58.6	58.5
Adell	64.4	65.3	65.8	55.4	55.4	55.6	55.4	55.4	55.2	55.0
Palace	106.0	108.3	109.6	82.0	81.8	81.7	81.1	80.8	80.3	79.9
Adell	76.0	76.8	77.2	66.5	66.3	66.4	66.2	66.3	66.1	66.1
Palace	106.9	109.2	110.5	88.4	88.0	87.8	87.1	86.7	86.1	85.7

Step 11

DDOR

DDOR Project ID	Substation/Subtransmission line	Circuit	Distribution Service Required	Operating Date	2022^A	2023^A	2024^A	2025^A	2026^A	2027^A	2028^A	2029^A	2030^A	2031^A	Units
DDOR_2022_DSP34759_334554	Chase 66/12 (D)	Palace	Capacity (UCT)	6/1/2025	1.39	1.54	1.65	1.85	2.11	2.28	2.35	2.35	2.30	2.26	MW
DDOR_2022_DSP34759_334554	Chase 66/12 (D)	Wyle	Capacity (UCT)	6/1/2025	0.00	0.15	0.28	0.52	0.80	1.09	1.20	1.20	1.17	1.26	MW

GNA

GNA ID	Substation / Subtransmission Line	Circuit	Distribution Service Required	Operating Date	Equipment Units	Deficiency (MW, MVAR, or Vpu)[1] 2022^A	2023^A	2024^A	2025^A	2026^A
GNA_2022_67	Chase 66/12 (D)	Palace	Capacity (UCT)	6/1/2023	MW	4.13	4.71	5.50	2.39	2.52
GNA_2022_70	Chase 66/12 (D)	Wyle	Capacity (UCT)	6/1/2024	MW	0.39	0.78	1.08	0.69	0.91

Step 12

The IPE verified Steps 9, 10, and 11 through a combination of demos performed by SCE and checks performed by the IPE.

7.2.2. Compile GNA Tables Showing Need and Timing – Step 12

This step reviews the analysis that determines if there is a grid need that requires action to be taken to address the need, the amount of the need, and the timing of the need. The GNA tables (that were filed in January) include only needs that exist after no cost solutions have been implemented. The process and calculations used to determine needs, after no cost solutions was reviewed in a previous step with examples for several need determinations, so they will not be repeated here. That review also demonstrate that the results of those reviews were reflected in the GNA/DDOR Report

7.3. PROCESSES TO DEVELOP PLANNED INVESTMENTS AND COSTS

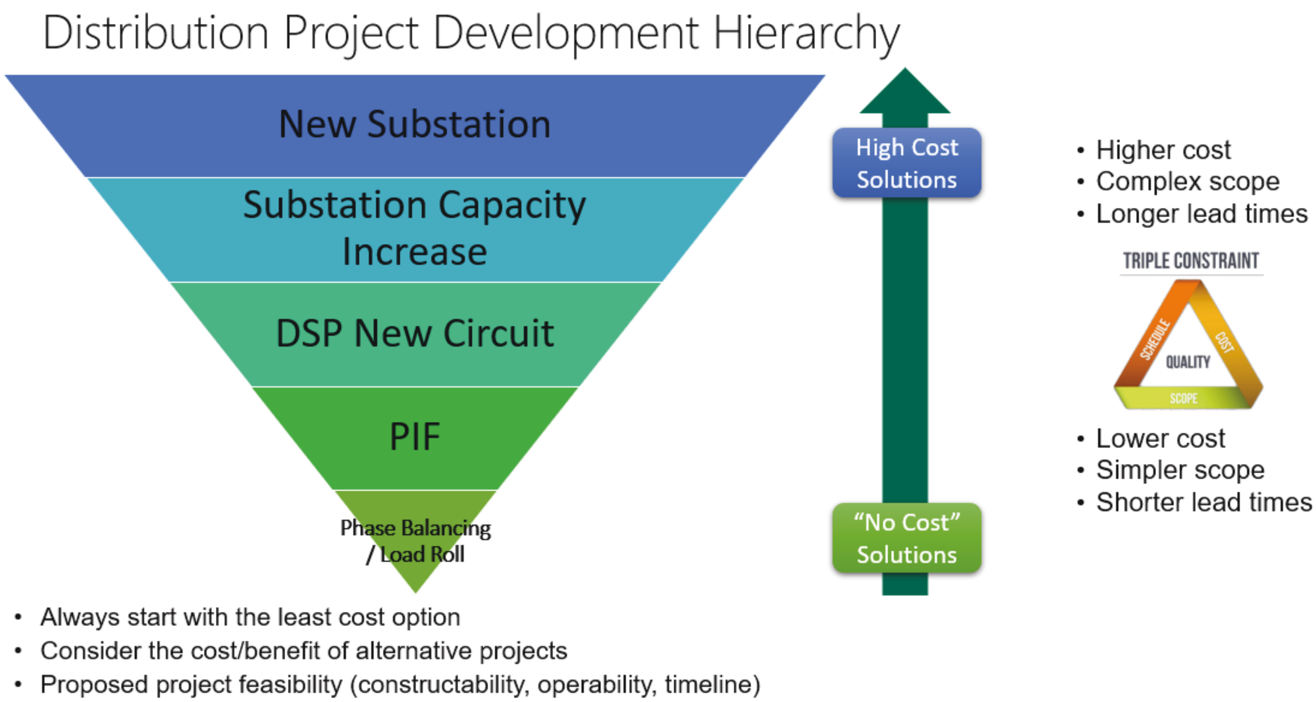
7.3.1. Develop Recommended Solution – Step 13

This step reviews the process that SCE used to determine the appropriate planned investment to meet the needs in the January 13, 2023 GNA Report. The following discussion reviews the process to determine planned investments for distribution needs and subtransmission needs.

The distribution investment hierarchy is shown in Figure 7-17 below. It highlights that the general process starts with determining if a no cost solutions (load transfers or load rolls and phase balancing) is available, and if not, then progresses to higher cost solutions until one is found that meets the need. At that point, the process determines if there are competing investments that are more cost effective.

The general options for distribution projects are shown in the graphic. The final proposed planned investment must also consider implementation issues including constructability and operability and time to complete the project.

Figure 7-17: Distribution Project Development Hierarchy



In Figure 7-18 we see an example of the selection of a new circuit as the least cost solution after considering all no cost solutions and an existing distribution circuit upgrade project (referred to as a PIF internally at SCE) solutions which would meet the need. The result is a planned investment of a new Jonagold 12kV out of the El Casco 115/12 substation which is included in the DDOR with a project id of DDOR_2022_331531.

Figure 7-18: Distribution Project Development Hierarchy – New Distribution Circuit

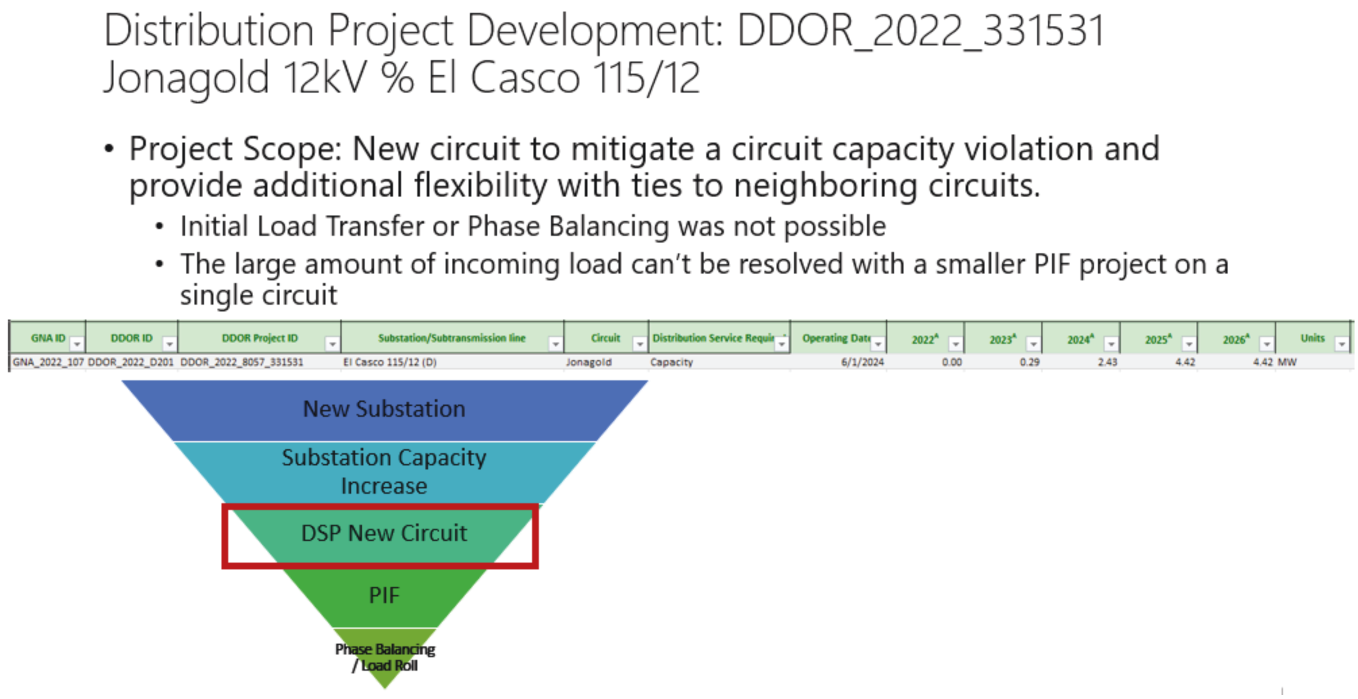


Figure 7-19 below shows the hierarchy for project selection for subtransmission project planned investments. There are three hierarchies depending upon the driver of the need including capacity violation, line loading violation and voltage violation.

Figure 7-19: Subtransmission Project Development Hierarchy

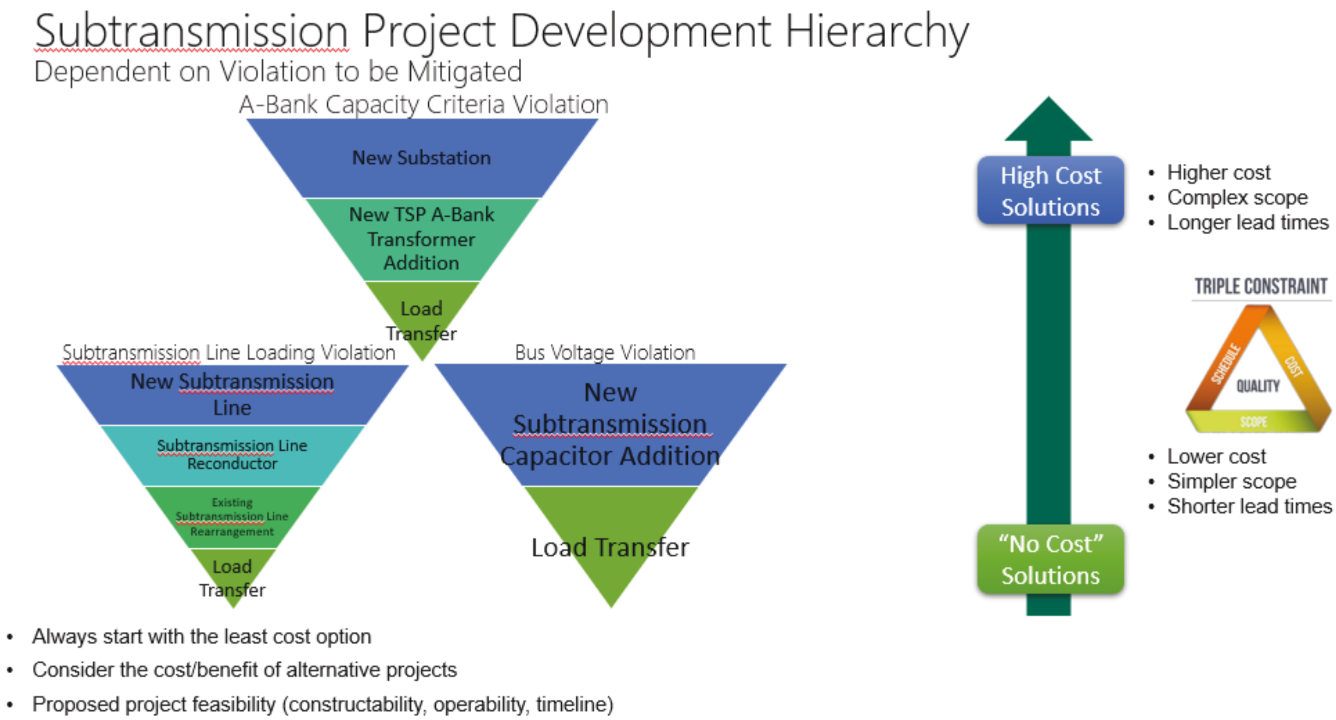
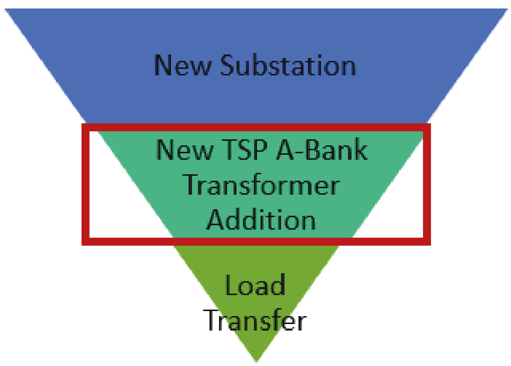


Figure 7-20 depicts the selection of a new 280 MVA transformer bank as the least cost best option after a load transfer was determined to be insufficient to address the need which is driven by a substation overload under N-1 conditions.

Figure 7-20: Subtransmission Project Development Hierarchy – New A Bank

Subtransmission Project Development: DDOR_2022_7767
Johanna 220/66 kV: Install New 280 MVA Transformer

- Project Scope: Install a new 280 MVA Transformer to mitigate an N-1 overload condition on Johanna 220/66 kV Substation.
  - A load transfer was not possible.



							Deficiency (MW, MVAR or VPU)					
GNA ID	DDOR ID	DDOR Project ID	Substation/Subtransmission line	Circuit	Distribution Service Requir	Operating Date	2022^	2023^	2024^	2025^	2026^	Units
GNA_2022_143	DDOR_2022_58	DDOR_2022_7767	Johanna 220/66 (S)	null	Reliability, Capacity	6/1/2024	10.00	21.10	26.90	26.20	27.30	MW

7.3.2. Estimate Capital Cost for Candidate Deferral Projects – Step 14

This step will review the process SCE used to develop the capital cost estimate contained in the DDOR and used to calculate LNBA values for a small sample of planned investments. The process used is shown below.

The graphic shown below provides an overview of the processes that SCE uses to develop and update cost estimates during the lifecycle of a project. The graphic also includes an approximate correlation between the steps in the lifecycle and the AACE Class. For example, at the project initiation step the cost estimate is based upon average costs based upon historical costs, the accuracy is comparable to an AACE Class 5 (-50% to +100%). Cost estimates contained in the September 2, 2022, DDOR filing were the for the most part AACE Class 5 estimates due to the abbreviated schedule.

SCE indicated that it develops detailed cost estimate breakdowns by equipment when filing its GRC for projects that have a substation component (e.g., substation expansion) and for subtransmission line projects. Cost estimates for new circuits are based on average historical costs until they move further into the project lifecycle. In off cycle GRC years, detailed cost estimates are not typically developed by SCE for any project until it moves from being identified in the annual planning process to design and engineering. This happens later in the project lifecycle and is generally when the project begins to accrue cost.

Figure 7-21: Project Cost Estimates

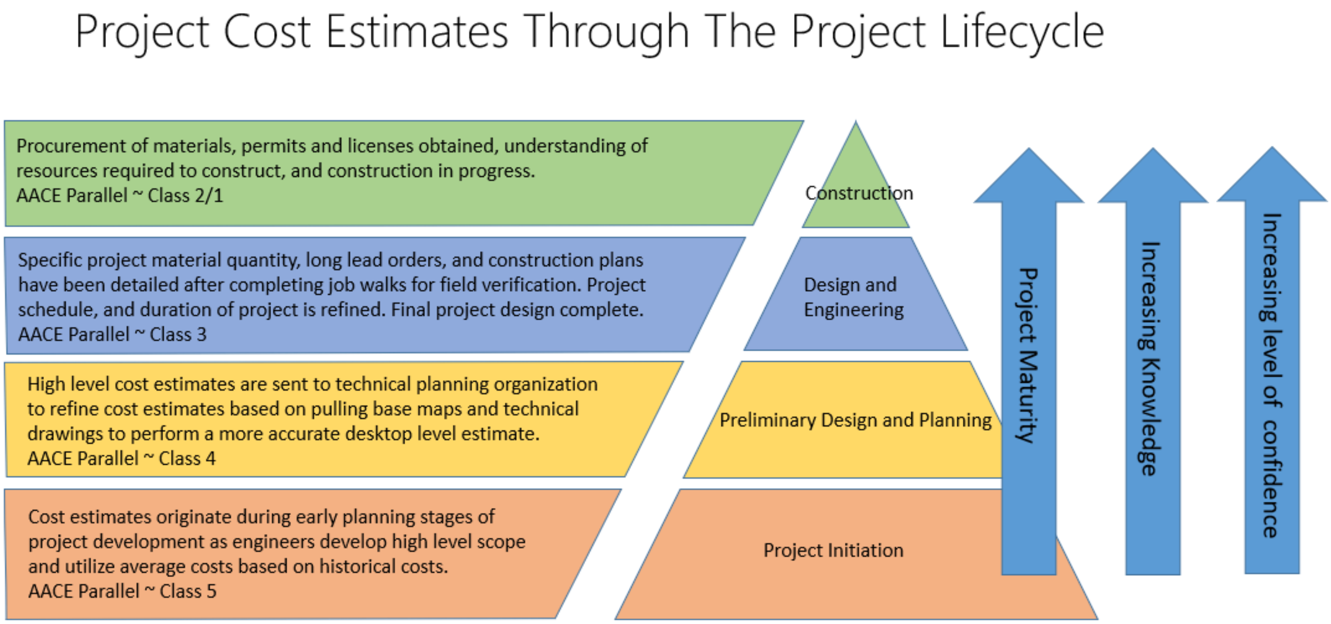


Figure 7-22: Cost Breakdown of Candidate Deferral Project Costs

Cost estimates used in DDOR – Candidate Deferrals

Project ID	Project Name	Substation	Substation Bank	Primary Feeder	Poles & Towers	Capacitors	Protection Equipment	IT	Total ($)
DDOR_2022_DSP26358_688019	New Circuit at Triton	$ 365,666	$ -	$ 2,638,763	$ -	$ -	$ -	$ -	$ 3,004,429
DDOR_2022_DSP34759_334554	New Circuit at Chase	$ 319,443	$ -	$ 2,730,394	$ -	$ -	$ -	$ 4,563	$ 3,054,400
DDOR_2022_8325_339553	New Circuit at Gonzales	$ 462,850	$ -	$ 2,083,862	$ -	$ -	$ -	$ 4,281	$ 2,550,993
DDOR_2022_8469_577046	New Transformer and New Circuit at Valley	$ 1,849,568	$ -	$ 2,114,008	$ -	$ -	$ -	$ 4,281	$ 3,967,857
DDOR_2022_8481	New Transformer at Mira Loma	$ 3,956,625	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,956,625
DDOR_2022_8476	New Transformer at Alessandro	$ 1,583,729	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,583,729
DDOR_2022_8438	New Capacitor at Channel Island	$ -	$ -	$ -	$ -	$ 1,596,844	$ -	$ -	$ 1,596,844
DDOR_2022_TSP STV35570	New Capacitor at Devers	$ -	$ -	$ -	$ -	$ 1,555,391	$ -	$ -	$ 1,555,391
DDOR_2022_DSP35666	Upgrade Transformers at North Oaks	$ 3,924,780	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,924,780
DDOR_2022_8425	Santa Clara-Colonia 66kV STL Rebuild	$ 683,021	$ -	$ 25,099,887	$ -	$ -	$ -	$ 106,476	$ 25,889,384
DDOR_2022_6698	Elizabeth Lake-Pitchgen 66kV STL Rebuild	$ 34,533	$ -	$ 6,474,624	$ -	$ -	$ -	$ 1,618	$ 6,510,775
DDOR_2022_TSP STL35672	Saugus-Haskell 66 kV STL Rebuild	$ 1,064,426	$ -	$ 8,021,353	$ -	$ -	$ -	$ 50,023	$ 9,135,802
DDOR_2022_6055	Mesa-Narrows 66kV STL Rebuild	$ 159,920	$ -	$ 3,666,970	$ -	$ -	$ -	$ -	$ 3,826,890
DDOR_2022_6871	Rector-Riverway No. 2 66kV STL Install	$ 3,042,014	$ -	$ 25,833,705	$ -	$ -	$ -	$ -	$ 28,875,719
DDOR_2022_4800	Del Valle Licensing Project	$ 135,554,237	$ -	$ -	$ -	$ -	$ -	$ -	$ 135,554,237
DDOR_2022_8256	Cal City Licensing Project	$ 333,439,731	$ -	$ -	$ -	$ -	$ -	$ -	$ 333,439,731
DDOR_2022_6092	Alberhill Licensing Project	$ 524,719,579	$ -	$ -	$ -	$ -	$ -	$ -	$ 524,719,579

SCE indicated that it develops detailed cost estimate breakdowns by equipment when filing its GRC for projects that have a substation component (e.g., substation expansion) and for subtransmission line projects. Cost estimates for new circuits are based on average historical costs until they move further into the project lifecycle. In off cycle GRC years, detailed cost estimates are not typically developed by SCE for any project until it moves from being identified in the annual planning process to design and engineering. This happens later in the project lifecycle and is generally when the project begins to accrue cost.

This year SCE, once again, took additional steps in an effort to more accurately represent the cost of new circuit projects that were included as CDOs in the September 2, 2022 filing – there was not sufficient time to do the same thing for new CDOs in the January 13, 2023 filing. Instead of relying on average historical costs for the CDOs in the September filing, SCE engineers calculated more detailed cost estimates for the distribution feeder element of these projects (equipment outside the substation). More detailed cost estimates were generated for this cost element because it is where variation between the average cost and more detailed cost of a new circuit project will most likely be observed based upon SCE's experience. These more detailed distribution feeder cost estimates account for things like the length of feeder, type of conductor, the amount of civil work, number of poles, and number of switches expected to be included in the scope of the new circuit project. SCE attempted to gain more accurate new circuit costs prior to better inform the candidate deferral prioritization process. SCE would not normally develop more detailed new circuit cost estimates for all projects as it is labor intensive and normally not necessary when evaluating projects on a portfolio level. Shown in the tables below are cost breakdowns for four different candidate deferral projects: two new distribution circuit projects, one new subtransmission line project, and one rebuild of a subtransmission line project. The IPE reviewed cost support information for these four projects and one Pre-Application CDO as described below.

- The IPE reviewed DDOR_2022_7978_959298: New 16kV Circuit at Elizabeth Lake 66/16 kV Substation as shown in the table below.

Project Cost Element	Cost ($K)
Distribution Substation	258
Distribution Lines	6,411
IT/Telecoms	4
Total Project Cost	**6,673**

- The IPE reviewed DDOR_2022_DSP34759_334554: New 12kV Circuit at Chase 66/12 kV Substation as shown in the table below:

Project Cost Element	Cost ($K)
Distribution Substation	216
Distribution Lines	2,563
IT/Telecoms	3
Total Project Cost	**2,782**

- The IPE reviewed DDOR_2022_6871: Install Rector-Riverway No. 2 66 kV Subtransmission Line as shown below

Project Cost Element	Cost ($K)
Distribution Substations	1,220
IT/Telecommunications	2,399
Licensing/Permitting	1,296
Real Properties	1,281
Subtransmission Lines	24,120
Transmission Substations	1,677
Total Project Cost	**31,993**

- The IPE reviewed DDOR_2022_8425: Rebuild Santa Clara-Colonia 66 kV Subtransmission Line as shown below

Project Cost Element	Cost ($K)
Distribution Lines	862
Distribution Substations	252
Environmental	20
IT/Telecommunications	104
Licensing/Permitting	128
Real Properties	20
Subtransmission Lines	23,722
Transmission Substations	249

- The IPE reviewed the cost support for the Cal City 115/12kV Substation which is a very large Pre-Application project. The project, with and overall cost of $334 Million, has extensive cost support information including a breakdown of the many costs elements that were used to develop the overall project costs. SCE notes that this project's detailed cost estimates continue to be update over time with new information and this project will be included in SCE's GRC filing planned for 2023. The supporting data includes lists of equipment for over 150 types of equipment (breakers, guyed wires, conductors, poles, protection equipment, etc.).

The IPE reviewed the projects listed above and found the supporting information to be reasonable.

7.4. PROCESSES TO DEVELOP CANDIDATE DEFFERAL LIST AND PRIORITIZE

7.4.1. Development of Candidate Deferral Projects – Step 15

This step will review the development of the list of Candidate Deferral Projects from the Planned Investment List through the application of Technical and Timing Screens.

The IPE verified Step 15 through the application of the timing screen to DDOR Planned Investments after the Planned Investments are identified in the January 2023 filing. The results of the verification matched the results included in SCE's GNA/DDOR Report.

The IPE verified Step 15 through the application of the timing screen to DDOR projects.

7.4.2. Development of Operational Requirements – Step 16

This step reviews the development of operational requirements for candidate deferral projects, which are used in the prioritization process as well as form the basis for any projects, which are included in a subsequent RFO or pilot procurement processes.

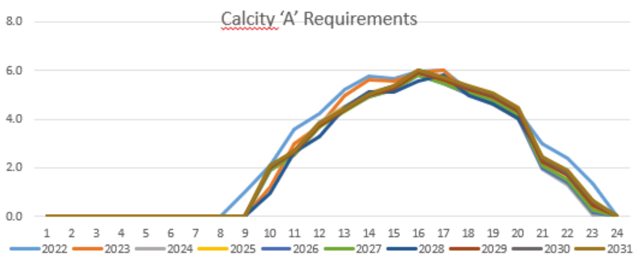
The process begins with the 8760 profile data developed for all candidate deferral projects in Steps 5, 6, and 7. SCE then uses a DER Solution Tool to process this 8760 net load data to determine hourly needs for three types of capacity projects – those with a single limit or rating which, for example, applies to banks and overhead lines, those with variable limits which, for example, applies to underground lines when underground cable temperature exceeds threshold and those that apply to projects with hierarchical needs, for example a project driven by a transformer and one or more circuits supplied by that transformer. This process includes a relatively new step which adjusts the SAS profile results to match the MDI planning results.

Example of DER Operational Requirements for Projects with Hierarchical Needs

The following set of plots demonstrates how operational requirements are developed for projects with hierarchical needs. A new 115/12 kV Cal City substation and two new 115kV subtransmission lines are planned to relieve the capacity limit exceedances on the Calcity 'A' 33/12 kV substation and the Greasewood 12 kV circuit served from it, as well as Calcity 'B' 33/12 kV substation and the Overall 12 kV circuit served from it. The needs are hierarchical because meeting the need on a circuit also meets a need on the substation that is supplying that circuit. To prevent over-procuring DERs unnecessarily, when developing DER operational requirements, SCE calculates the incremental substation need after all circuit needs are met by comparing the hourly needs on the substation and circuit(s).Figure 7-23 shows the requirements of the Calcity "A" substation, Figure 7-24 shows the requirements of the Greasewood circuit that is fed by the Calcity "A" substation and Figure 7-25 shows the net requirements at the Calcity "A" substation assuming the Greasewood circuits requirements are met.

Figure 7-23: Calcity "A" 33/12 Requirements

DER Attribute Requirements: Calcity 'A' 33/12

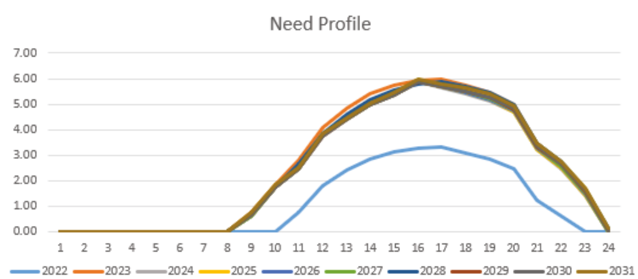


Capacity (MW)	Energy Need (MWh)	Season	Monthly Frequency	Yearly Frequency	Year
6.0	60.5	Spring, Summer	31	95	2022
6.0	54.2	Summer	30	75	2023
5.9	52.2	Summer	29	70	2024
5.9	52.3	Summer	29	70	2025
5.8	51.4	Summer	28	70	2026
5.8	51.9	Summer	28	65	2027
5.8	51.4	Summer	30	75	2028
5.9	53.5	Summer	29	70	2029
6.0	54.7	Summer	30	70	2030
6.0	55.1	Summer	30	70	2031

	Peak Hourly Need (MW)																							
Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
2022	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	2.1	3.6	4.2	5.2	5.7	5.7	6.0	6.0	5.2	4.8	4.3	3.0	2.4	1.3	0.0
2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2	3.0	3.8	5.0	5.6	5.6	5.9	6.0	5.0	4.6	4.0	2.4	1.7	0.4	0.0
2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	2.7	3.9	4.5	5.1	5.4	5.9	5.5	5.0	4.7	4.1	2.0	1.3	0.1	0.0
2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	2.7	3.8	4.5	5.1	5.3	5.9	5.5	5.1	4.7	4.1	2.0	1.4	0.2	0.0
2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9	2.6	3.7	4.4	4.9	5.2	5.8	5.5	5.0	4.7	4.1	2.0	1.4	0.2	0.0
2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9	2.6	3.7	4.3	4.9	5.2	5.8	5.5	5.1	4.8	4.2	2.1	1.5	0.3	0.0
2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9	2.6	3.3	4.5	5.1	5.1	5.6	5.8	5.0	4.6	4.0	2.5	1.8	0.6	0.0
2029	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	2.6	3.8	4.4	5.0	5.3	5.9	5.6	5.2	4.9	4.3	2.3	1.7	0.5	0.0
2030	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.1	2.7	3.8	4.5	5.0	5.4	6.0	5.7	5.3	5.0	4.4	2.4	1.8	0.6	0.0
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.1	2.7	3.8	4.4	5.0	5.4	6.0	5.7	5.4	5.1	4.5	2.4	1.9	0.7	0.0

Figure 7-24: Calcity "A" 33/12 Greasewood 16kV Circuit Requirements

DER Attribute Requirements: Calcity 'A' 33/12 – Greasewood 16kV

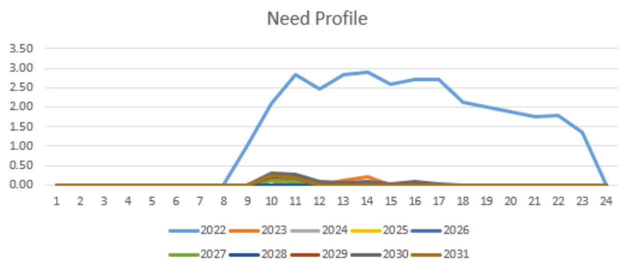


Capacity (MW)	Energy Need (MWH)	Season	Monthly Frequency	Yearly Frequency	Year
3.3	27.5	Summer	29	80	2022
6.0	61.1	Spring, Summer	31	110	2023
5.9	57.5	Spring, Summer	31	105	2024
5.9	57.6	Spring, Summer	31	105	2025
5.9	57.7	Spring, Summer	31	105	2026
5.9	58.0	Spring, Summer	31	105	2027
5.9	60.1	Spring, Summer	31	105	2028
5.9	58.1	Spring, Summer	31	105	2029
5.9	58.3	Spring, Summer	31	105	2030
6.0	59.5	Spring, Summer	31	105	2031

	Peak Hourly Need (MW)																							
Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
2022	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	1.8	2.4	2.8	3.1	3.3	3.3	3.1	2.8	2.4	1.2	0.6	0.0	0.0
2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	1.8	2.8	4.1	4.8	5.4	5.7	5.9	6.0	5.7	5.4	5.0	3.5	2.7	1.6	0.0
2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	1.8	2.5	3.8	4.5	5.0	5.4	5.9	5.7	5.4	5.1	4.7	3.2	2.5	1.4	0.0
2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	1.8	2.5	3.8	4.5	5.0	5.4	5.9	5.7	5.4	5.2	4.7	3.2	2.5	1.4	0.0
2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	1.8	2.5	3.8	4.4	5.0	5.4	5.9	5.7	5.4	5.2	4.7	3.3	2.5	1.5	0.0
2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	1.8	2.5	3.8	4.4	5.0	5.4	5.9	5.7	5.5	5.2	4.8	3.3	2.6	1.5	0.0
2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	1.7	2.6	3.9	4.6	5.2	5.5	5.8	5.9	5.7	5.4	5.0	3.5	2.8	1.7	0.1
2029	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	1.8	2.4	3.8	4.4	5.0	5.4	5.9	5.7	5.5	5.3	4.8	3.3	2.6	1.6	0.0
2030	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	1.8	2.4	3.7	4.4	5.0	5.4	5.9	5.7	5.5	5.3	4.8	3.4	2.7	1.6	0.0
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	1.8	2.5	3.8	4.5	5.0	5.4	6.0	5.8	5.6	5.4	4.9	3.5	2.8	1.7	0.1

Figure 7-25: Calcity "A" 33/12 Net Requirements

DER Attribute Requirements: Calcity 'A' 33/12 Net



Capacity (MW)	Energy Need (MWH)	Season	Monthly Frequency	Yearly Frequency	Year
2.9	32.9	Spring, Summer	31	95	2022
0.2	0.5	Summer	5	15	2023
0.2	0.7	Summer	5	15	2024
0.2	0.4	Summer	5	15	2025
0.1	0.2	Summer	5	15	2026
0.1	0.2	Summer	5	15	2027
0.0	0.0	N/A	0	0	2028
0.2	0.4	Summer	5	15	2029
0.3	1.0	Summer	5	15	2030
0.2	0.4	Summer	5	15	2031

	Peak Hourly Need (MW)																							
Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
2022	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	2.1	2.8	2.4	2.8	2.9	2.6	2.7	2.7	2.1	2.0	1.9	1.8	1.8	1.3	0.0
2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2029	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2030	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.1	0.1	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

The IPE verified Step 16 primarily through a demo performed by SCE and cross checks performed by the IPE.

7.4.3. Prioritization of Candidate Deferral Projects into Tiers – Step 17

This step reviews the Excel spreadsheet that SCE used to implement its project prioritization process. A review of the validity and results is included in Section 5.

The Excel spreadsheet provided by SCE calculates all of the values of the three prioritization metrics and their components, as well as an overall score for each Candidate Deferral Project.

All calculations in the spreadsheet were checked for adherence to the SCE description of its prioritization process.

The IPE verified Step 17 through the IPE performing a review of the proper workings of the SCE Excel spreadsheet and IPE crosscheck of spreadsheet inputs.

7.4.4. Calculate LNBA Values – Step 18

Development and Use of LNBA Values

The Locational Net Benefits Analysis (LNBA) value is the unitized net present value (NPV) of the savings associated with deferring a planned project. The deferral value is the revenue requirement associated with the planned project which includes annualized capital and operations and maintenance (O&M)

costs. The LNBA value is typically expressed as a $/MW-year value, determined by dividing the deferral value by the product of two values – the number of years of deferral and the maximum amount (MW) of need during the deferral period. The LNBA value is used as an indicator of the economic feasibility of a non-wire solution. A non-wire solution project with a higher value of LNBA would indicate, in general, that it is a more economically feasible than a project with a lower value. In the DDOR report, actual LNBA values (i.e., not ranges) are reported for both Planned Investments and Candidate Deferral projects. The LNBA values are also used in the calculation of prioritization metrics.

Approach

We reviewed the methodology that SCE used to develop the LNBA values that it included in its DDOR Report. A summary of that review follows.

Deferral Timeframe

Deferral period is a key input to the LNBA calculation. In the 2022 DDOR, as in prior DDORs, SCE uses a 10-year deferral timeframe as required by the 2020 May ALJ Ruling Reform #5. For example, if the operating date of a project is in 2025, then the deferral period is 7 years (i.e., defer from 2025 to 2031). SCE will calculate the LNBA values for planned investments (provided in units of $/MW-yr, $/Vpu-yr, or $/MVAR-yr).

LNBA Calculation

The deferral value associated with the deferral of a planned project is the NPV of all the annual deferral values during the deferral timeframe. For example, the 10-year deferral value is the sum of the Net Present Values (NPV) of the 1-year deferral value of the proposed solution for the first ten years. The 1-year deferral value of the proposed solution is the sum of the 1-year deferral value of the equipment capital cost and the operations and maintenance (O&M costs) associated with the new equipment that would have been added if the traditional project had been built. In the E3-based LNBA calculation tool, the deferral value for a multi-year deferral is calculated using a single NPV formula and not as the sum of the NPV of 1-year deferral values as stated above.

The 1-year deferral value associated with equipment is calculated by multiplying the revenue requirement for the project with the RECC factor.

*1-Year deferral value = Project Revenue Requirement * RECC,*

Where RECC is defined by the following equation:

$$\text{RECC} = \frac{(r-i)}{(1+r)}\left(\frac{(1+r)^N}{(1+r)^N-(1+i)^N}\right)$$

Where, i= assumed inflation over the period of interest, r = assumed discount rate, and N = is the assumed life of the traditional project.

The Project Revenue Requirement is calculated by multiplying the estimated capital cost of the equipment with the Revenue Requirement Multiplier (RRQ Multiplier or RRM). The RRQ Multiplier represents costs recovered from utility customers and includes costs such as taxes, franchise fees, utility authorized rate of return, and overheads. In equation form, the Project Revenue Requirement is:

*Project Revenue Requirement = Estimated Project Capital Cost * RRQ Multiplier*

If a DER is procured instead of building a traditional wires project, utility customers also benefit by avoiding any annual O&M activities associated with the traditional wires project equipment which is not built. Since O&M is an expense item that is passed to customers in the year it is incurred, it is not multiplied by the RECC factor or the RRM. Since O&M costs are incurred in the year they are performed, O&M cost is also subject to inflation adjustments.

The complete expression of the cost reduction associated with a one-year deferral is thus:

Deferral Benefit = [[Project Capital Cost] x [RECC Factor] x [RRQ Multiplier] + annual O&M]

To calculate the value of a multiple-year deferral, the yearly deferral values for each year, after the first year, are calculated and simply discounted to a present value using a discount factor derived from same discount and inflation rates used in the RECC factor and then the discounted values are summed together to form the multiple year deferral value. The E3-based LNBA calculation tool used by SCE calculates the multi-year deferral using a single NPV formula with the year of deferral as an input, instead of summing the NPV of 1-year deferrals.

The key assumptions for the LNBA calculation include the following:

- Discount Rate: Derived from the utility's weighted average cost of capital.
- Inflation Rate: Inflation rates for equipment and O&M as assumed as per utility's practice.
- Life of a Traditional Project: Assumptions for project life as per utility's practice.
- Equipment Capital Cost: Cost of the project equipment as per utility's practice.
- O&M Costs: Cost of O&M as per utility's practice. Expressed as a percentage of the project's capital cost.

In general, SCE's LNBA calculations followed the same calculations as those included in the E3 LNBA tool. However, SCE used their own set of assumptions for the key inputs to the deferral calculation. The inputs and outputs of SCE's LNBA calculation are discussed below.

Key inputs

The key inputs to the LNBA calculation are shown in the table below. Only the inputs corresponding to substations, primary feeders, and IT are shown in the Table below for simplicity because those were the only ones used. SCE used a discount rate of 10%. SCE indicated that the 10% discount rate is equal to SCE's incremental cost of capital. SCE's incremental cost of capital is intended to be a forward-looking long-term cost of capital, whereas SCE's authorized cost of capital is a short-term cost of capital that largely reflects the cost of existing financing, not new or incremental financing. One other key input for the LNBA calculation is the capital cost of equipment for each project.

Table 7-1: Key Inputs

Parameters	Substation	Primary Feeder	Protection Equipment	Source
Revenue Requirement Multiplier	1.12	1.17	1.15	SCE updated value
Equipment Inflation (%/yr)	2.5%	2.5%	2.5%	SCE updated value
O&M Inflation (%/yr)	1.5%	1.5%	1.5%	SCE updated value
O&M Factor	1.6%	1.6%	1.6%	SCE updated value
Book Life (yrs)	67	33	49	SCE updated value
RECC	0.069	0.076	0.071	Calculated
Discount rate net or project inflation (%/yr)	7.4%	7.4%	7.4%	Calculated
Discount rate net of O&M inflation (%/yr)	8.3%	8.3%	8.3%	Calculated

Results

The IPE verified the inputs that went into the LNBA calculation, as well as the calculation itself for DDOR_2022_DSP26358_688019. This project involves Substation upgrades and primary feeder related costs.

7.4.5. Compare Forecast and Actuals at Circuit Level for 2021 – Step 19

This step includes a comparison of forecasted and actual loads for 2021. This is a review that was included for the last two cycles. In the 2021 DIDF cycle, the comparison was made for the Candidate Deferral Circuits with actuals and forecast to be made on the same basis – in that case on a 1 in 10-year basis. Based upon a recommendation in the 2020 DIDF cycle, the comparison made in the 2021 report (again on a 1-in-10 basis) is for a "statistically significant" number of circuits which has been set at 10% of number of all circuits. The purpose is to get some insight into the "accuracy" of the overall circuit planning process recognizing that there are many variables that can affect the comparison that are beyond the control of the utility.

A comparison of the percent difference in the actual and forecasted load from the 2020-21 and 2021-22 DIDF cycles are shown in Figures 7-26 and 7-27 respectively. These percent differences were calculated for both cycles as the actual load less the forecast load divided by the actual load for roughly 300 circuits which were randomly selected for this analysis.

Figure 7-26: Percent Difference between Forecast and Actual – 2020/2021 Cycle

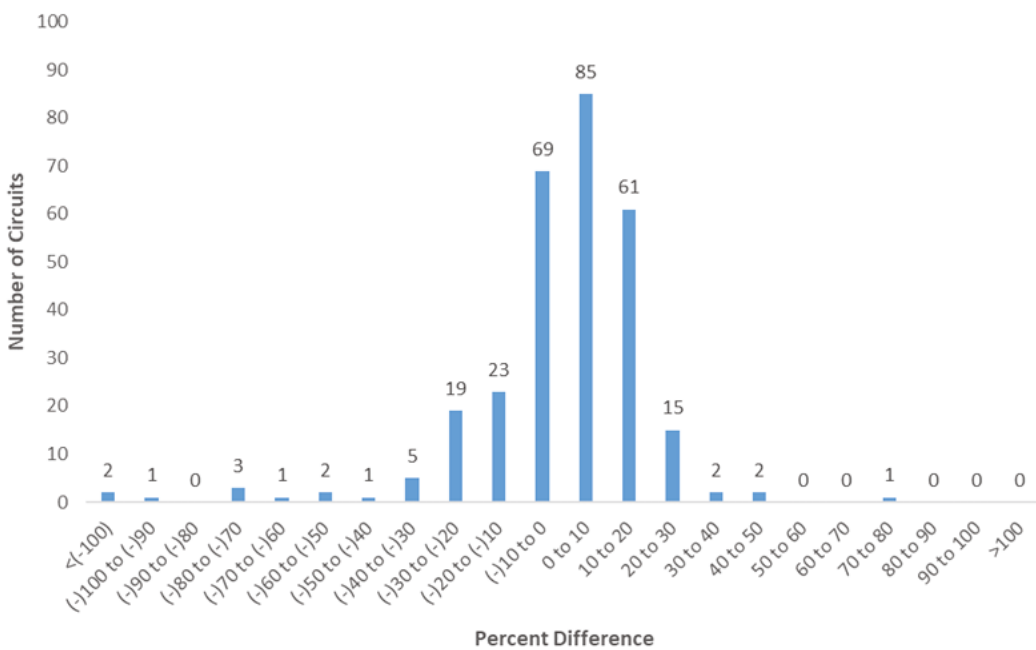
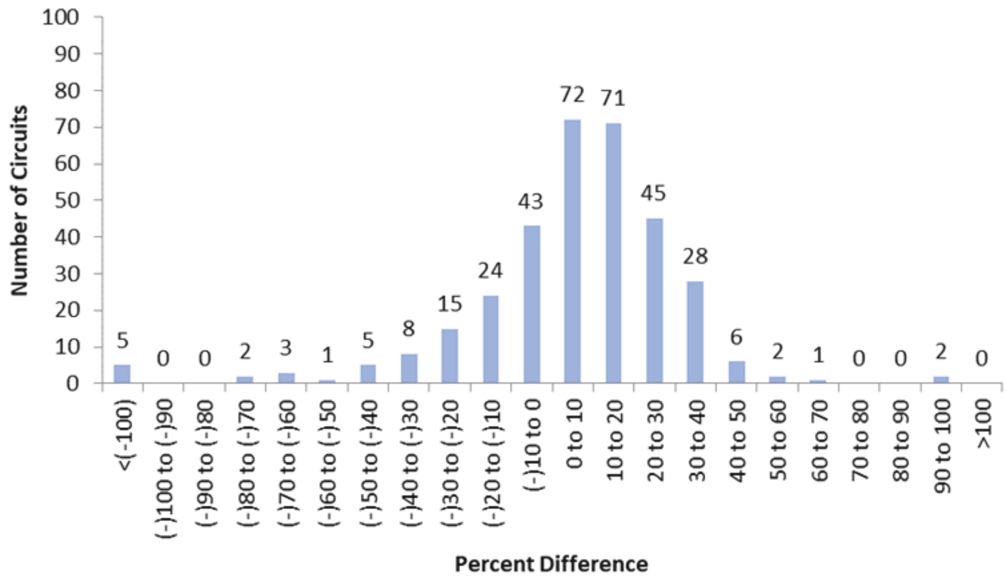


Figure 7-27: Percent Difference between Forecast and Actual – 2021/2022 Cycle



The bars on the right side of the histogram plot (those with positive values) show the number of circuits where the actual load is higher than the forecasted load. Conversely, the bars on the left side of the plot show the number of occurrences where the actual load is lower than forecast. In the plot for the current cycle, we see that roughly 80% of the forecast errors (272 out of 335 circuits in the figure) have forecast errors in the range of -30% to +30%.

It can also be seen that there is a slight bias to the right, (i.e., there are more circuits with positive errors than negative errors). This means that the actual load for more than half of the circuits is higher than the forecast load – of the 333 circuits 227 or 68% had positive errors indicating that the forecast was lower than the actual.

Reviewing the data for the previous cycle (2020/2021), we also see a similar bias to the right (actuals greater than forecast – of the 292 circuits 166 or 56% have actuals greater than forecast.

7.5. OTHER IPE WORK

7.5.1. Review Implementing of Planning Standard and/or Planning Process – Step 20

This review was completed in the 2020 DIDF cycle and no follow up work was planned for this cycle.

7.5.2. Review List of Internally Approved Capital Projects – Step 21

This review was completed in the 2020 DIDF cycle. A small number of follow up was recommended for the 2021 cycle which was completed in March 2022.

7.5.3. Respond to and Incorporate DPAG Comments – Step 22

The IPE was available during the SCE DPAG meeting and the SCE Follow-Up DPAG meeting to respond to questions raised. There were no written questions posed to the IPE by DPAG stakeholders.

7.5.4. Track Solicitation Results to Inform Next Cycle – Step 22

This review was completed in Q3 of 2022. A solicitation tracking tool (XCEL workbook) was developed by the utilities' Independent Evaluators (IE) at the Direction of the Energy Division. The IPE participated in the definition of the data to be tracked. Going forward the IEs for each utility will update the information in the tracking tool on a regular basis.

7.5.5. Treating confidential material in the IPE report – Step 24

The IPE work products have followed the process and steps included in this Business Step in developing the IPE Final Report. Additional actions were taken to minimize the material that is redacted in the Public version of this report to maximize the readers ability to understand what the IPE did during this DIDF cycle.

Appendix A IPE Scope

R.14-08-013, A.15-07-005, *et al.* ALJ/RIM/nd3

Attachment A
Listing of Schedule and IPE-Specific Reforms for the 2020-2021 DIDF Cycle

1. IPE-specific reforms for the 2020-2021 DIDF Cycle are implemented within the IPE Scope of Work presented in Attachment B.

2. IOU contracts with the IPE for the full scope of work identified in Attachment B shall be executed by the IOUs to allow for IPE Plan development to begin as soon as possible, ideally on or before **April 17, 2020**.

3. The IOUs shall work with the IPE and Energy Division to develop IPE Plans specific to each IOU such that the IPE can submit the Draft IPE Plans to Energy Division for review on or before **May 15, 2020**.

4. The IPE scope of work may be modified by Energy Division as needed for the IPE to successfully complete each assignment. The IOUs will promptly submit a Tier 1 Advice Letter to notice changes in scope should a scope change differ significantly from the scope described in Attachment B. Minor changes should not necessitate an Advice Letter filing.

5. As required by Energy Division on an annual basis, Pre-DPAG and Post-DPAG activities may include workshops; new, re-opened, suspended, or modified working groups (e.g., Distribution Forecast Working Group); and IOU presentations and deliverables.

6. During the Post-DPAG period and in consultation with the IPE, Energy Division may identify exemplary GNA/DDOR documentation components, analytical approaches, or data strategies implemented by one or more IOUs and require that each IOU implement the reform in future DIDF cycles.

(end of Attachment A)

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Attachment B
IPE Scope of Work for DIDF Implementation

Term

- January 1st each year to July 31st the following year with the term subject to update by Energy Division if needed to support each DIDF cycle.

Pre-DPAG Period

- Develop an ***IPE Plan*** for each IOU describing the GNA/DDOR review process and detailed approach to Verification and Validation of all data used by the IOUs to prepare their DIDF filing materials.
  - Verification and Validation will include a thorough investigation of the following IOU processes, among others:
    - Collecting circuit loadings and performing weather adjustments;
    - Determining load and DER annual growth on the system level;
    - Disaggregating load and DER annual growth to the circuit level;
    - Checking sum of all disaggregated load and DERs against system-level values;
    - Adding incremental known loads to circuit level forecasts;
    - Developing load, DER, and net load profiles and determining net peak loads;
    - Adjusting for extreme weather;
    - Comparisons to equipment ratings to determine if ratings will be exceeded;
    - Incorporating load transfers, phase transfers, correcting data errors;
    - Compiling GNA tables showing need amount and timing; and
    - Following the IOU's planning standard and/or planning process.
  - GNA/DDOR report review will include an in-depth analysis of the following IOU steps, among others:
    - Developing recommended solutions (planned investments);
    - Implementing the IOU's planning standards and/or planning process;
    - Estimating capital costs for planned investments;

- Developing list of candidate deferral projects through application of screens (timing and technical);
- Developing operational requirements;
- Prioritization of candidate deferral projects into tiers;
- Calculating LNBA values; and
- Comparing prior-year forecast and actuals at circuit level for candidate deferral projects.

- Work directly with the IOUs and Energy Division to develop draft plans as needed. Development of the draft IPE Plans may include, among other activities:
  - Meeting with the IOUs and Energy Division to identify and understand each business process and tool used to complete their GNA/DDOR filings.
- Facilitate or participate in stakeholder workshops to receive feedback on the IPE Plans.
- Review and incorporate comments in the final IPE Plans.
- Submit final IPE Plans to Energy Division and the IOUs with recommendations for future improvements to the plans.
- Other technical support assignments as defined by Energy Division to ensure the IPE and Energy Division will receive from the IOUs the data and cooperation necessary to complete the required evaluation of the GNA/DDOR filings.

DPAG Period

- Participate in all workshops and meetings during the DPAG period. Prepare and deliver presentations or handouts as requested by Energy Division (*e.g.*, final IPE Plan presentations).
- Develop an ***IPE Preliminary Analysis of GNA/DDOR Data Adequacy*** for all three IOUs.
- Review any comments on the preliminary analysis that may be received and discuss the results with Energy Division.

- Facilitate meetings with Energy Division and the IOUs to correct data inadequacies and prepare further documentation and provide technical support as needed.
- Fully implement each IPE Plan as defined in the final IPE Plans.
- Develop an ***IPE DPAG Report*** for each IOU presenting GNA/DDOR review findings and Verification & Validation outcomes.
- Submit the draft reports to Energy Division for review and (if necessary) to the IOUs to check for confidential information that may be included or to clarify specific details.
- Circulate the final IPE DPAG Reports to stakeholders (public and confidential versions).
- Other technical support assignments as defined by Energy Division to ensure the DPAG process is successfully completed.

Sample Size

- The scope of review conducted by the IPE for each IOU process may encompass the full set of circuits/projects or a subset/sample of circuits or projects. Where sampling is determined to be appropriate by the IPE in consultation with Energy Division, the size of the sample set for each case will be determined by the IPE based on the application of engineering judgement.

Post-DPAG Period

- Develop a single ***IPE Post-DPAG Report*** covering all three IOUs; comparing their current and prior filings; evaluating DIDF DER procurement, operational, cost, and contingency planning outcomes; reviewing IOU compliance; and making recommendations for process improvements and DIDF reform.
- Coordinate with and support the Independent Evaluator (IE) with IE activities and the development of IE reports as needed.
- Submit the draft report to Energy Division for review and (if necessary) to the IOUs to check for confidential information that may be included.

Appendix B Copy of the IPE Plan

Note: The 2022/2023 IPE Plan for SCE is included following this page. This version of the Plan is updated to reflect the final dates for all the steps and reflects steps taken before and after SCE's abbreviated DDOR filing on September 2, 2022 and its full GNA/DDOR filing on January 13, 2023.

Report

Independent Professional Engineer Plan Southern California Edison - Final

Submitted to California Public Utility Commission

May, 2022

Revised November, 2022, March, 2023

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Contents

1 Introduction and Background

This document is the draft version of the Independent Professional Engineer Plan for the 2022/2023 Distribution Investment Deferral Framework (DIDF) cycle for Southern California Edison. The requirements for the plan and oversight by the Energy Division are spelled out in a CPUC Ruling 14-08-013 (April 13, 2020) which is attached as Appendix A. The Ruling modified the Distribution Investment Deferral Framework (DIDF) process and previous rulings with respect to the Independent Professional Engineer (IPE) scope of work and provided the updated 2020-2021 DIDF cycle schedule. As of writing this draft report, the 2022/2023 cycle schedule has not been finalized.

As a result of stakeholder comments regarding improving the effectiveness of the IPE process, schedule and expected results, a number of modifications were made by the Ruling and implemented for the first time in in the 2020/2021 DIDF cycle. These changes have been incorporated in the IPE Plans developed ever since. Some of these changes are highlighted below:

- The IPE review process now starts earlier to allow for more time for the IPE, utilities and the Energy Division to perform the necessary production of data in response to data requests, verify and validate the data, produce reports and address the confidentiality of data in the reports prior to the IPE Report deadline. The review process starts in the late-April timeframe.
- The IPE scope includes development of a draft IPE Plan for each utility by mid-May in each cycle. The plan goes through a stakeholder review cycle and will be issued in final form by the IPE in August.
- The scope of the IPE review was expanded to include several new business processes
- The scope of the review was expanded to include the new CPUC Standard Offer Contract (SOC) and Partnership Pilots (PP).
- The original schedule for IPE deliverables was established in the CPUC 2020 Rulings for the 2020/2021 cycle[1]:
  - Draft IPE Plan. Due May 13, 2020 (Reflects 2021/2022 cycle dates)
  - Final IPE Plan. Due August 27, 2020. (Reflects 2021/2022 cycle dates)
  - IPE Preliminary Analysis of GNA/DDOR Data Adequacy for all three IOUs. Due 9/9/20. (Reflects 2021/2022 cycle dates)

[1] Dates shown below were originally set forth per the 2020 Ruling. The CPUC plans to issue a ruling with dates for the 2022/2023 DIDF cycle in May. These updated dates will be included in the Final SCE IPE Plan.

- IPE DPAG Report for each IOU presenting GNA/DDOR review findings and Verification & Validation outcomes. Due 11/15/20. (Reflects 2021/2022 cycle dates)
- IPE Post DPAG Report covering all three IOUs, comparing their filings, reviewing compliance, and making recommendations for process improvements and DIDF reform. Due March 17, 2022. (Reflects 2021/2022 cycle dates)
- The May 2022 draft IPE Plan will be distributed to stakeholders in May to facilitate stakeholder comments prior to finalizing the IPE Plan in August 2022.
- Note that as a result of SCE's plan to submit an abbreviated DDOR on Sept 2, 2022 and a Final GNA.DDOR Report on January 13, 2023, the final IPE Plan will be completed and distributed prior to January 13, 2023.

2 Description of the Plan

2.1 Definitions Used in the Plan and Other Deliverables

To facilitate understanding of the IPE scope of work, the following definitions are included and will be used in the Plan and throughout all of the IPE work products and deliverables.

> Verification – Is a review performed by the IPE during which an independent check is performed to determine if the results produced were developed using data assumptions and business processes that were defined and described by the utility or are based upon standard industry approaches that do not have to be defined and described. In other words, "Did the IOU follow their own processes correctly as defined and described by the IOU?"
>
> Validation – Is a review performed by the IPE during which an independent assessment is performed of the appropriateness of the approach taken by the utility to perform a task from an engineering, economics and business perspective. In other words, "Are the processes implemented by the IOU the best way to identify all planned investments that could feasibly be deferred by DERs cost effectively? And to what extent were the IOU methodologies appropriate and effective?"

The IPE Plan covers the business processes that the IOUs use to identify which distribution or subtransmission projects are recommended to proceed to 1) an RFO, 2) Standard Offer Contract or 3) Partnership Pilot seeking DER bids to determine if there is a cost-effective non-wires alternative. One of the core purposes of the plan is to answer the question - Are the IOUs identifying every project that could feasibly and cost effectively be deferred by DERs?

The business processes in the Plan are organized generally in the order that they are performed. Starting with capturing the peak load values for each circuit for 2021, using the CEC IEPR forecasts to develop utility specific system level values which are then disaggregated to the circuit level adjusted for known loads then used to determine if there is an overload or other issue during the planning period (nominally 2022 through 2026). For circuits that have a need, a planned investment is selected, capital costs developed for that project and the planned investments are screened to develop a list of candidate deferral projects. These candidate deferral projects are then prioritized into tiers using several metrics with the projects in the first tier normally recommended for a DER RFO. Candidate deferral projects are also considered for SOC or PP pilot programs based upon the results of the prioritization process along with additional set of metrics for SOC and PP pilots.

As indicated earlier, in the 2021/2022 cycle two new pilot programs were initiated that are testing new mechanisms to procure DERs. They are called the Partnership Pilot and a Standard

Offer Contract. These pilots impact other parts of the business processes covered in the IPE Plan.

3 IPE Plan

The heart of the IPE Plan is the material contained in Table 3-1 below. This table lists the business processes, roles of the utility and IPE, target timing and information requirements for each business process in the IPE scope. Listed below is a more detailed description of the contents of Table 3-1:

- IOU Business Process / IPE Review Step – This column includes a number for each business process included in the table. To make it easier for readers who will be looking at more than one utility IPE Plan, the process was started with the same numbering for all three utilities and that set of numbers was maintained as much as possible. In cases where additional steps needed to be added to accommodate a utilities specific unique process a letter was added to the previous number. For example, the step after Step 3 was added and was number Step 3a. For cases where steps are not needed, they will be spelled out in the table.
- Business Process / IPE Review Step Description – This column contains a general description of the business process being reviewed.
- Plan for 2022/23 DIDF Cycle – This column includes several types of information:
  - A brief description of what the review will include and whether it would include review of a subset of the total number of elements (i.e., circuits) or all elements and what is being examined.
  - Roles which include the role of the utility overall and the role of the IPE for both the verification and validation review. For both reviews, an indication is provided for what the IPE will be checking for or confirming in the review.
    Note that there are generally two approaches to performing a verification. The first is a demonstration wherein the utility develops the necessary spreadsheet or other mechanism to show how the business process developed the results of interest and the IPE performs a walk through to view the demonstration by the utility. The second approach is wherein the IPE develops a spreadsheet or other mechanism to calculate the results of interest using data provided by the utility and then compares the results to the numerical utilities results.
- Target Timing – This column includes a target timing for the reviews in the business process in this row or in the timing that data will be provided to the IPE. The dates are based upon the previous cycle and will be adjusted to reflect the planned dates for this cycle in the Final IPE Plan to be distributed in mid-August.
- Data/Information Requirements – This column includes the data or information that the IPE needs to perform its review and in some cases the date the information is required.

Table 3-1 SCE IPE Review for 2022/23 DIDF Cycle is shown starting on the following page.

Table 3-1: SCE IPE Review for 2022/2023 DIDF Cycle

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
PROCESSES TO DEVELOP STARTING POINT LOAD, SYSTEM LEVEL VALUES AND DISAGGREGATE TO CIRCUIT LEVEL				
1	Collect 2021 actual circuit loading and adjust for weather as needed	Perform Verification for a subset of circuits selected by the IPE in consultation with the IOU; check results including weather normalization to typical weather day and extreme weather day. Examine weather adjustment factors/relationships for all SCE regions. The review in this Step will include the process described in Step 8 below. Roles: SCE to develop demonstration of weather adjusted readings for 20 circuits (SCADA data) throughout the SCE territory including an overview of the process used. Demonstration to include review of data measurements (SCADA Data) and process to adjust to standard conditions required by following steps of the load forecasting process with a focus on the peak day.	7/14/2022 with Data Refresh 12/14/22	▪ Description of business process used to collect and adjust measurement (does this include peak load for one day for each circuit?) ▪ General methodology of weather adjustment factors ▪ Demonstration of measurements/adjustments for 20 selected circuits.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		SCE to demonstrate general methodology of weather adjustment factors for the selected circuits within its service territory. This also includes adjustments due to extreme weather (e.g., 1-in-10). Verification: IPE to review demonstrations and compare the process and results to the process described/presented by SCE. IPE to verify that individual circuit results are used in the following steps in the load forecasting process (Step 4). Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
2	Determine load and DER annual growth on system level	Perform Verification and Validation on all aspects of this process Roles:	7/7/2022 with Data Refresh 12/14/22	▪ Provide description of CEC IEPR system forecast used (i.e., low, medium or high) and link to table(s) used, as available

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		SCE to demonstrate how it used the CEC IEPR system level (annual energy) load and DER forecasts as the basis for its load and DER disaggregation process. SCE to demonstrate how the data for known loads for commercial chargers is used in conjunction with the CEC IEPR data for EVs to avoid double counting these loads. SCE to provide spreadsheet(s) that demonstrates this process. Verification: IPE to review data provided (spreadsheet) and compare to process summary presented by SCE. IPE to compare output results of this process are the same as those used in the next step of the process (Step 3). IPE to verify that SCE used the load forecast scenario that was approved by the CPUC for use in the DIDF. Validation:		▪ Provide description of the process if different than used in 2021 and described in 2021 GNA/DDOR ▪ Provide available spreadsheet used to implement process ▪ Summary data of local known loads that are assumed to be embedded in the CEC IEPR. This data to include type of load, magnitude and timing and circuit.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
3	Disaggregate load and DER annual growth to the circuit level	Perform Verification for a subset (approximately 10) of circuits selected by the IPE in consultation with SCE. Roles: SCE to demonstrate how it used the results of the previous step (utilization of the approved CEC IEPR system level (annual energy) load and DER forecasts) in the process of allocating system level annual energy values of load and DERs to the circuit level. Verification: IPE to review demonstration and compare results to process summary presented by SCE. IPE to compare results for select individual circuits against results used in following steps in the process (starting in Step 4)	7/7/2022 with Data Refresh 12/14/22 Note – the cross checks portion of this step (compare results for selected circuits against results used in the following steps) have a Target Date after the GNA report is filed.	Demonstrations and associated spreadsheet.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
3a	Check sum of all disaggregated load and DERs same as CEC IEPR System Level values	Perform Verification on this aggregation for all circuit values as well as cross check values used in other Verification checks. Roles: SCE to demonstrate that the sum of all circuit level energy values for load and DERs equals the approved CEC IEPR system level values verified in Step 2. Verification: IPE to verify that the sums of all circuit load and DER values equals to (within a small deviation) the CEC IEPR system values verified in Step 2. IPE to verify that selected circuit values used in the summation check match the circuit values used in subsequent steps of the load forecasting process (starting in Step 4).	7/7/2022 with Data Refresh 12/14/22	Demonstrations

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		This check will also include a check of known loads at the system level against the sum of the known loads at the circuit level. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
4	Add Incremental load growth projects to circuit level forecasts (those loads assumed not in CEC forecast)	Perform Verification for a subset (approximately 10) of circuits selected by the IPE in consultation with the IOU Roles: SCE to demonstrate how it adds incremental known loads for cases where the load is in addition to the CEC system level load forecast. SCE to demonstrate how loads are added and any adjustments to system level values are accomplished. Note: Load that is embedded within CEC IEPR growth is already captured within Business Process Steps 2, 3, and 3a. Verification:	7/14/2022 with Data Refresh 12/14/22	▪ Summary of local known loads and values for loads that are not included in CEC forecasts ▪ Description of discussions with CEC regarding local know loads that are not included in CEC forecasts

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		IPE to verify that business process demonstration by SCE is the same as described in SCE documentation. IPE to verify that the results for selected circuits are used in subsequent business process steps (Starting with Step 5) Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
5	Convert peak growth to 8760 profile as needed	Perform Verification and Validation for a subset (approximately 10) of circuits selected by the IPE in consultation with the IOU. Roles: SCE to demonstrate how it converts load and DER results of previous steps into 8760 values. Verification: IPE to verify that process reflected in the demonstration is the same as described by SCE. Validation:	7/14/2022 with Data Refresh 12/14/22	Description of process used for load and DERs in tabular view.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
6	Derive net load profile	Perform Verification for a subset (approximately 10) of circuits selected by the IPE in consultation with the IOU. Roles: SCE to demonstrate how it combines load and DER on an 8760 basis to obtain a net load profile. Verification: IPE to verify that process reflected in the demonstration is the same as described by SCE. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.	7/14/2022 with Data Refresh 12/14/22	Description of process used to combine load and DERs in tabular view.
7	Determine net peak load	Perform Verification for a subset (approximately 10) of circuits selected by the IPE in consultation with the IOU.	7/14/2022 with Data Refresh 12/14/22	Description of process used to determine peak impact using shapes.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		Roles: SCE to demonstrate the process of how it applies shapes to determine peak impact of different growth types (e.g., disaggregated growth before shapes vs. after shapes) similar to the 2019 V/V approach. Verification: IPE to verify that process reflected in the demonstration is the same as described by SCE. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
8	Adjust for "extreme weather"	This verification and validation are included in Step 1.	7/14/2022 with Data Refresh 12/14/22	

PROCESSES TO DETERMINE CIRCUIT NEEDS AND DEVELOP GNA

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
9	Initial comparison to equip. ratings to determine if ratings exceeded	Perform Verification for a subset of circuits selected by the IPE in consultation with the IOU. Note: The verification and validation of this business process is included in Step 11.	After January 13, 2023 SCE GNA/DDOR filing – February 10, 2023	
10	Evaluate no cost solutions - incorporate load transfers, phase balancing, correct data errors	Perform Validation and Verification for a subset (approximately 6) examples pulled from separate circuits selected by the IPE in consultation with the IOU. Roles: SCE to demonstrate how it makes adjustments to forecast based upon load transfers, phase balancing, and/or data error corrections. Demonstration will include what data is relied upon to predict the impact of making the proposed changes (i.e., load transfer). Verification: IPE to verify the process reflected in the SCE demonstration is consistent with the SCE description and the result are the same as used	After January 13, 2023 SCE GNA/DDOR filing– February 10, 2023	Description of general process used to evaluate no cost solutions.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		in subsequent steps in process of developing the GNA. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
11	Comparison to equip. ratings to determine if ratings exceeded	Perform Verification for a subset (approximately 10) of circuits selected by the IPE in consultation with the IOU. Note the business processes described in Step 9 is covered in this step. Roles: SCE to demonstrate how it determines if there is a "need" and how it determines the need amount. This will include comparison of extreme weather load forecast against appropriate ratings for distribution circuits (overhead and underground). For subtransmission circuits SCE will demonstrate how it uses contingency analysis to determine if there is a need and to determine a need amount. The demonstration will include comparisons where no cost load	After January 13, 2023 SCE GNA/DDOR filing– February 10, 2023	Description of process used to determine need/deficiency amount. Description of ratings and their basis used in this step.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		transfers and phase balancing is included for some of the selected circuits. Verification: IPE to verify the process reflected in the SCE demonstration is consistent with the SCE description and the result are the same as used in subsequent steps in process of developing the GNA. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
12	Compile GNA tables showing need amount and need timing, etc. (consistent with IOU's documented planning standards and/or planning process)	Perform Verification on development of GNA table entries for select circuits also confirming that planning standard/process was followed as appropriate. Roles: SCE to provide confidential version of Planned Investment tables in Excel format that can be filtered by the IPE.	After January 13, 2023 SCE GNA/DDOR filing– February 10, 2023	▪ Confidential GNA tables in Excel format provided by mid-August ▪ Copy of planning standard if different than one used in 2021. ▪ Description of process used using excerpts from planning assumptions,

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		SCE to provide list of planning standards/criteria that were used in the development of the GNA tables. Verification: IPE to verify GNA tables are consistent with previous steps verified and planning standard as appropriate. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		GNA, and DDOR similar to approach in 2021 cycle. ▪ This step focuses upon an analysis concerning whether planning standards that lead to the identification of needs were followed. It does not include review of the planning standards, themselves.
PROCESSES TO DEVELOP PLANNED INVESTMENTS AND COSTS				
13	Develop recommended solution and generate list of Planned Investments (follow the IOU's	Perform Verification for a subset (approximately 6) of projects selected by the IPE in consultation with the IOU confirming that planning standard/process was followed. Roles:	After January 13, 2023 SCE GNA/DDOR filing–February 21, 2023	Description of process used to develop proposed planned project to address identified need for distribution and subtransmission projects.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
	documented planning standards and/or planning process)	SCE to demonstrate/describe process used to determine recommended planned solution for a subset of projects including subtransmission and distribution projects. Verification: IPE to verify the SCE demonstration reflects the description of the process provided by SCE. IPE to verify that results shown in the demonstration follow the described process are same as included in DDOR. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
14	Estimate capital cost for Candidate Deferral Projects	Perform Validation and Verification for a subset (approximately 6) of Candidate Deferral projects selected by the IPE in consultation with the IOU. Roles: SCE to provide information describing the processes used to develop the capital cost estimates included in the DDOR.	11/4/22 Update - February 21, 2023	▪ Information describing the processes used to develop costs and how it relates to the SCE GRC. ▪ Expected Accuracy associated with the process described

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		SCE to describe the Expected Accuracy Level (as defined by AACE or by another method that describes the expected accuracy range in terms of % lower and higher than the estimate) of the capital costs for the Candidate Deferral Projects included in the DDOR. If the Expected Accuracy is different for different projects, SCE to provide the accuracy range for each project.[1] SCE to provide supporting cost information for a subset of projects. Projects to include small, medium and large projects and new projects and those that have been included in previous DDOR reports. Verification: IPE to verify that the supporting information for the selected projects confirms the process that was used and that the cost data supplied supports the final cost estimate provided by SCE and included in the DDOR.		▪ Support cost data for subset of projects in DDOR

[1] During the course of implementing the IPE Plan, the ED in coordination with the IPE will seek to understand the effort and cost associated with improving the accuracy of capital cost estimates (i.e., from a Class 4 estimate accuracy to a Class 3 estimate accuracy).

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
PROCESSES TO DEVELOP CANDIDATE DEFFERAL LIST AND PRIORITIZE				
15	Development of Candidate Deferral Projects list through application of screens (timing and technical)	Perform Verification for all projects put through screens Roles: SCE to provide confidential version of Planned Investment table in Excel format that can be filtered by the IPE. SCE to describe the process it used to develop its Candidate Deferral Projects. Verification: IPE to use the Excel tables to develop a list of Candidate Deferral Projects following the process described by SCE. IPE to verify its result (list of Candidate Deferral Projects) match the SCE results included in the DDOR.	11/4/22 Update - February 21, 2023	▪ Confidential version of Planned Investment table in Excel format that can be filtered by the IPE. ▪ Description of process used to develop Candidate Deferral Projects ▪ Utilize DPAG materials

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
16	Development of operational requirements (daily, monthly annually etc.)	Perform Verification for a subset (approximately 4) of Candidate Deferral projects selected by the IPE in consultation with the IOU. Roles: SCE to demonstrate how it developed the operational requirements for a subset of candidate deferral projects including several Tier 1 projects. Verification: IPE to observe results demonstrated by SCE and check to see that they are consistent with the net load shapes and forecasts for the selected projects and that they match the results in the DDOR. Validation:	11/4/22 Update - February 21, 2023	Describe general methodology similar to 2021 approach. Provide demonstration similar to 2021 cycle.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
17	Prioritization of candidate deferral projects into Tiers	Perform Verification on prioritization process for all candidate deferral projects including process to develop list of projects that SCE recommends proceed to RFO, SOC or PP procurement. Roles: SCE to provide active version (not just values) of the Excel spreadsheet that calculates the metrics and their components used to rank the Candidate Deferral Projects overall and into tiers. Note, in the 2021/2022 cycle the IOUs have agreed to use a single standard methodology to prioritize/rank Candidate Deferral Projects and to place them in various tiers based upon the prioritization results. SCE to provide active version of spreadsheet (if one is used) used to rank and select candidate deferral projects for procurement using the SOC or PP procurement programs. Verification:	11/4/22 Update - February 21, 2023	▪ Demonstrate active spreadsheet that calculates prioritization metrics, components and ranks projects on those results. To include spreadsheets for prioritization of CDOs and for ranking/selecting SOC and PP projects. ▪ Description of the IOU standardized prioritization metrics, components and tier ranking methodology and process and SOC and PP ranking selection process – all provided by end of-August.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		IPE to verify that spreadsheet calculations are consistent with the description of the standard IOU prioritization/ranking and tier placement methodology and SOC and PP ranking/selection process. IPE to verify that Excel results match the recommended Candidate Deferral Projects overall rankings and placement into tiers and recommended for RFO, SCO or PP procurement included in the DDOR and presented at the DPAG meetings. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
18	Calculate LNBA ranges and values for all planned investments	Perform Verification for a subset of candidate deferral projects (approximately 6) selected by the IPE in consultation with the IOU. Roles: SCE to provide an active spreadsheet (not just values) that calculates all LNBA range values	11/4/22 Update - February 21, 2023	▪ Description of the process used to develop LNBA ranges and metric values ▪ Demonstrate active spreadsheet that calculates prioritization metrics and components.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		that are included in the DDOR for all Candidate Deferral Projects. SCE to provide an active spreadsheet that calculates all LNBA metrics used in the project prioritization process (if different than values in the spreadsheet previously listed. Verification: IPE to verify that LNBA values are developed using a methodology that is the same as the one described by SCE. IPE to verify results are the same as those included in the DDOR and project ranking process. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
19	Compare 2021 forecast and actuals at circuit level for selected	Perform comparison of forecasted and actual loads for a statistically meaningful number of distribution circuits to be selected by the IPE in conjunction with SCE. In 2021, data from 337 circuits was compared.	February 15, 2023	Forecasted data from 2021 GNA/DDOR and recorded data from the 2022 Distribution Planning Process

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
	number of distribution circuits	Roles: SCE to demonstrate comparison of 2021 actual loads (as recorded and as adjusted) against 2021 Plan Year's forecasted 2021 load values. Verification: IPE to review SCE demonstrated process, values and compare differences. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		

OTHER IPE WORK

20	Review implementing of planning standard and/or planning process	No further review is planned for the 2022/2023 DIDF cycle	N/A	
21	Review list of internally	No further review is planned for the 2022/2023 DIDF cycle.	N/A	

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
	approved capital projects			
22	Respond to and incorporate DPAG comments	Include in Final IPE Plan.	Completed	
23	Track solicitation results to inform next cycle	Part of IPE Post-DPAG Report follow-on activities in coordination with the IE.	Q3-2022	
24	Treating confidential material in the IPE report	Confidentiality – the following steps will be followed to ensure that the IPE Reports treat confidential material consistent with the rules and procedures of the CPUC: a. Hold an early meeting with IOU (and potentially the ED) to 1) Identify what data and documents the IPE intends to include within its reports 2) discuss process for SCE to flag those items they intend to request Confidentiality treatment and on what basis within the identified data and documents the IPE intends to use. IPE may provide feedback to ED in lieu of having the ED attend the meeting with the IOU and IPE. Discussion held by September 15.	Target Dates listed in third column are aligned with the 2021/2022 DIDF cycle schedule and will be updated in the Final IPE Plan.	SCE requires a list of documents and data the IPE intends to use within their report so that SCE can have adequate time to analyze data and perform confidentiality redactions. The data/documents need to be provided in a reasonable amount of time for SCE to provide both public and confidential versions of documents by October 22, 2021, and the draft report by October 29, 2021.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		b. IOU provides public version of any documents[2] for which they will seek confidential treatment prior to period IPE is wrapping up report. Date: October 22, 2020. At this point the IPE should have two sets of documents that were provided by SCE – one that contains documents that can be included in the public version of the report (all confidential information will be redacted) and a second set that has confidential information that is readable, but such information is highlighted to show that it is confidential. This second set would be included as part of the confidential version of the IPE Report. c. IPE provides the final two sets of documents to the IOU by October 26 that will be included in the IPE Report for the IOUs final confidentiality review. d. IPE provides the confidential versions of the body of the draft IPE Report to the		

[2] Documents refers to any document provided to the IPE by the IOU that was not included in the IOU's public version of the GNA/DDOR reports. These documents will be included as attachments to the body of the IPE report as required by a CPUC ruling.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		IOU by October 29; the body of the report to include all but the documents provided in previous item) for final IOU confidentiality review. e. IOU provides comments/markups of documents after final confidentiality review by November 4 from their review of all documents and by November 5 from their review of the draft IPE report body. Markups of the body of the report will include marking up the confidential version highlighting what data is designated as confidential (data that was not previously designated as confidential). f. After review and signoff, the IPE produces final Confidential Report on CPUC schedule and provides to ED and IOU – November 11. Between November 5th and 11th the IPE and IOU work together to produce the final public version of the body of the report to ensure all confidential information is properly redacted in the		

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2021/22 DIDF Cycle	Target Timing	Data/Information Requirements
		public version of the report. On November 11th the public version is also provided to the ED and IOU. g. IOU requests CPUC Confidential Treatment using standard procedures. h. IOU files Public IPE Report version on CPUC schedule – DIDF Advice Letters submitted – November 15, 2020 i. IOU files revised Public Report if CPUC rejects any requests for confidential treatment; otherwise, process is complete and no further action is needed. In the 2021/2022 cycle the IPE Plan was revised to assist the IPE to avoid using tables, plots, graphs or other data that are included in the IPE DPAG Report that end up needing to be redacted to meet the IOU's requirements. This should help to reduce the amount of redaction in the Public version of the IPE DPAG Report and make it easier for stakeholders to understand it.		

Appendix A CPUC 4/13/20 Ruling Excerpts

R.14-08-013, A.15-07-005, *et al.* ALJ/RIM/nd3

Attachment A
Listing of Schedule and IPE-Specific Reforms for the 2020-2021 DIDF Cycle

1. IPE-specific reforms for the 2020-2021 DIDF Cycle are implemented within the IPE Scope of Work presented in Attachment B.

2. IOU contracts with the IPE for the full scope of work identified in Attachment B shall be executed by the IOUs to allow for IPE Plan development to begin as soon as possible, ideally on or before **April 17, 2020**.

3. The IOUs shall work with the IPE and Energy Division to develop IPE Plans specific to each IOU such that the IPE can submit the Draft IPE Plans to Energy Division for review on or before **May 15, 2020**.

4. The IPE scope of work may be modified by Energy Division as needed for the IPE to successfully complete each assignment. The IOUs will promptly submit a Tier 1 Advice Letter to notice changes in scope should a scope change differ significantly from the scope described in Attachment B. Minor changes should not necessitate an Advice Letter filing.

5. As required by Energy Division on an annual basis, Pre-DPAG and Post-DPAG activities may include workshops; new, re-opened, suspended, or modified working groups (e.g., Distribution Forecast Working Group); and IOU presentations and deliverables.

6. During the Post-DPAG period and in consultation with the IPE, Energy Division may identify exemplary GNA/DDOR documentation components, analytical approaches, or data strategies implemented by one or more IOUs and require that each IOU implement the reform in future DIDF cycles.

(end of Attachment A)

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R.14-08-013, A.15-07-005, *et al.* ALJ/RIM/nd3

Attachment B
IPE Scope of Work for DIDF Implementation

Term

- January 1st each year to July 31st the following year with the term subject to update by Energy Division if needed to support each DIDF cycle.

Pre-DPAG Period

- Develop an ***IPE Plan*** for each IOU describing the GNA/DDOR review process and detailed approach to Verification and Validation of all data used by the IOUs to prepare their DIDF filing materials.
  - Verification and Validation will include a thorough investigation of the following IOU processes, among others:
    - Collecting circuit loadings and performing weather adjustments;
    - Determining load and DER annual growth on the system level;
    - Disaggregating load and DER annual growth to the circuit level;
    - Checking sum of all disaggregated load and DERs against system-level values;
    - Adding incremental known loads to circuit level forecasts;
    - Developing load, DER, and net load profiles and determining net peak loads;
    - Adjusting for extreme weather;
    - Comparisons to equipment ratings to determine if ratings will be exceeded;
    - Incorporating load transfers, phase transfers, correcting data errors;
    - Compiling GNA tables showing need amount and timing; and
    - Following the IOU's planning standard and/or planning process.
  - GNA/DDOR report review will include an in-depth analysis of the following IOU steps, among others:
    - Developing recommended solutions (planned investments);
    - Implementing the IOU's planning standards and/or planning process;
    - Estimating capital costs for planned investments;

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  - Developing list of candidate deferral projects through application of screens (timing and technical);
  - Developing operational requirements;
  - Prioritization of candidate deferral projects into tiers;
  - Calculating LNBA values; and
  - Comparing prior-year forecast and actuals at circuit level for candidate deferral projects.
- Work directly with the IOUs and Energy Division to develop draft plans as needed. Development of the draft IPE Plans may include, among other activities:
  - Meeting with the IOUs and Energy Division to identify and understand each business process and tool used to complete their GNA/DDOR filings.
- Facilitate or participate in stakeholder workshops to receive feedback on the IPE Plans.
- Review and incorporate comments in the final IPE Plans.
- Submit final IPE Plans to Energy Division and the IOUs with recommendations for future improvements to the plans.
- Other technical support assignments as defined by Energy Division to ensure the IPE and Energy Division will receive from the IOUs the data and cooperation necessary to complete the required evaluation of the GNA/DDOR filings.

DPAG Period

- Participate in all workshops and meetings during the DPAG period. Prepare and deliver presentations or handouts as requested by Energy Division (*e.g.*, final IPE Plan presentations).
- Develop an ***IPE Preliminary Analysis of GNA/DDOR Data Adequacy*** for all three IOUs.
- Review any comments on the preliminary analysis that may be received and discuss the results with Energy Division.

- Facilitate meetings with Energy Division and the IOUs to correct data inadequacies and prepare further documentation and provide technical support as needed.
- Fully implement each IPE Plan as defined in the final IPE Plans.
- Develop an ***IPE DPAG Report*** for each IOU presenting GNA/DDOR review findings and Verification & Validation outcomes.
- Submit the draft reports to Energy Division for review and (if necessary) to the IOUs to check for confidential information that may be included or to clarify specific details.
- Circulate the final IPE DPAG Reports to stakeholders (public and confidential versions).
- Other technical support assignments as defined by Energy Division to ensure the DPAG process is successfully completed.

Sample Size

- The scope of review conducted by the IPE for each IOU process may encompass the full set of circuits/projects or a subset/sample of circuits or projects. Where sampling is determined to be appropriate by the IPE in consultation with Energy Division, the size of the sample set for each case will be determined by the IPE based on the application of engineering judgement.

Post-DPAG Period

- Develop a single ***IPE Post-DPAG Report*** covering all three IOUs; comparing their current and prior filings; evaluating DIDF DER procurement, operational, cost, and contingency planning outcomes; reviewing IOU compliance; and making recommendations for process improvements and DIDF reform.
- Coordinate with and support the Independent Evaluator (IE) with IE activities and the development of IE reports as needed.
- Submit the draft report to Energy Division for review and (if necessary) to the IOUs to check for confidential information that may be included.

- Submit the final report to Energy Division and prepare public versions as needed.
- Support Energy Division with their review of DIDF reform comments, including comments on any IPE tasks.
- Support Energy Division's review of RFO materials and RFO outcomes.
- Attend RFO and procurement meetings and provide technical support as requested by Energy Division.
- Coordinate with the Independent Evaluator to support their evaluation and provide technical support at the discretion of Energy Division.
- Other technical support assignments as defined by Energy Division to develop and evaluate potential DIDF reforms and track and evaluate deferral opportunities that may be subject to ongoing review in other proceedings (e.g., pursuant to General Order 131-D).

<u>List of IPE DIDF Deliverables</u>

1. ***IPE Plan*** for each IOU describing the GNA/DDOR review process and approach to Verification & Validation for the underlying data.
2. ***IPE Preliminary Analysis of GNA/DDOR Data Adequacy*** for all three IOUs.
3. ***IPE DPAG Report*** for each IOU presenting GNA/DDOR review findings and Verification & Validation outcomes.
4. ***IPE Post-DPAG Report*** covering all three IOUs, comparing their filings, reviewing compliance, and making recommendations for process improvements and DIDF reform.

(end of Attachment B)

Submitted by:

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Appendix C Documents Received

The IPE received many sets of data from SCE during the review. Listed below are the documents provided to the IPE during the course of the review. In many cases these data sets are presentations (Power Point) that were used in demonstrations of the various business processes in the plan. In addition, numerous spreadsheets and PDFs and/or Word documents were provided. These actual documents are provided as separate files from the body of this report due to their size.

Three lists of documents that were provided to the IPE by SCE are shown below. One lists the set of documents that are considered Public since they do not contain any confidential information. The second list contains all of the documents that are declared confidential and are not available to the public. The third list is a list of documents that are included in both the Confidential and Public versions of the DPAG Report set of files.

Please contact the IPE to obtain a copy of these documents.

C.1 List of Documents Provided – Public Set

Name	Size
2022 DIDF__IDER Pilot Selection Criteria_For IPE (Public).xlsx	28 KB
2022 PY - Step 19 Circuit Selection Sample Size (Public).xlsx	42 KB
2022 SCE DDOR_Public - Full Filing.xlsx	0 KB
2022 SCE DDOR_Public - Partial Filing.xlsx	0 KB
2022 SCE GNA_Public - Full Filing (No Partial Filing).xlsx	0 KB
R2106017 SCE 2022 GNA-DDOR Report - Public - Full Filing.pdf	0 KB
R2106017-SCE 2022 DDOR - Public - Partial Filing.pdf	0 KB
SCE.021023.IPE_Steps 9-12 Presentation (Public).pptx	1,721 KB
SCE.070722.IPE_Steps 1,8 (Public).pptx	32,989 KB
SCE.071422.IPE_Step 4 (Public).pptx	4,984 KB
SCE.110422.IPE_Steps 14-18 Presentation (Public).pptx	32,550 KB
SCE.121422.IPE_Step 4 - UPDATE(Public).pptx	4,729 KB
SCE.121422.IPE_Steps 1,8 - UPDATE (Public).pptx	32,922 KB
SCE-IPE_20-Circuits-Summary-Table_Public - ReRun.xlsx	157 KB
SCE-IPE_20-Circuit-Summary-Table_Public.xlsx	174 KB

D.2 List of Documents Provided – Confidential Set

Name	Size
2022 DIDF__IDER Pilot Selection Criteria_For IPE (Confidential).xlsx	31 KB
2022 PY - Step 19 Circuit Selection Sample Size (Confidential).xlsx	45 KB
2022 SCE DDOR_Confidential - Full Filing.xlsx	0 KB
2022 SCE DDOR_Confidential - Partial Filing.xlsx	0 KB
2022 SCE GNA_Confidential - Full Filing.xlsx	0 KB
R2106017 SCE 2022 GNA-DDOR Report - Confidential - Full Filing.pdf	0 KB
R2106017-SCE 2022 DDOR - Confidential - Partial Filing.pdf	0 KB
SCE.021023.IPE_Steps 9-12 Presentation (Confidential).pptx	1,721 KB
SCE.070722.IPE_Steps 1,8 (Confidential).pptx	34,081 KB
SCE.071422.IPE_Step 4 (Confidential).pptx	5,431 KB
SCE.110422.IPE_Steps 14-18 Presentation (Confidential).pptx	32,557 KB
SCE.121422.IPE_Step 4 - UPDATE (Confidential).pptx	5,178 KB
SCE.121422.IPE_Steps 1,8 - UPDATE (Confidential).pptx	34,018 KB
SCE-IPE_20-Circuits-Summary-Table_Confidential - ReRun.xlsx	160 KB
SCE-IPE_20-Circuit-Summary-Table_Confidential.xlsx	179 KB

D.3 List of Documents Provided – Common Set

Name	Size
2022 DIDF_Known Loads Report - Full Filing.xlsx	127 KB
2022 DIDF_PP SOC Selection Criteria for IPE.pptx	124 KB
2022 SCE Joint Prioritization Metrics Workbook - Full Filing.xlsx	1,006 KB
2022 SCE Joint Prioritization Metrics Workbook - Partial Filing.xlsx	0 KB
2022 SCE Known Load Projects - Partial Filing.xlsx	0 KB
SCE.021523.IPE_Step 19 Presentation.pptx	1,570 KB
SCE.022123.IPE_Step 13 Presentation.pptx	420 KB
SCE.022123.IPE_Steps 14-18 Data Refresh Presentation.pptx	754 KB
SCE.070722.IPE_Steps 2-3a.pptx	3,513 KB
SCE.071422.IPE_Steps 5-7.pptx	8,982 KB
SCE.121422.IPE_Steps 5-7 - UPDATE.pptx	8,816 KB
SCE.121422.IPE_Steps_2-3a - UPDATE.pptx	3,186 KB
Starting Point SCE DPAG Report v5SentMolly_SCE.docx	6,734 KB
Steps 2-3a_IEPR Load DER System Ckt Data.xlsx	1,227 KB

Distribution Investment Deferral Framework: Evaluation and Recommendations

Prepared for: California Public Utilities Commission, Energy Division

Proceeding R.21-06-017 (Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future)

Submitted by:

Kevala, Inc.
55 Francisco Street, Suite 350
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November 14, 2022

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Acknowledgments

Kevala would like to thank the following individuals for providing input, answering questions, and reviewing the report.

- **California Public Utilities Commission (CPUC) Energy Division** including Robert Peterson, Gabe Petlin, Ramandeep Bagri, and Tyler Nam.
- **CPUC High DER proceeding consultancy team** including Stephan Barsun and Kurt Scheuermann from Verdant Associates.
- **Resource Innovations'** Independent Professional Engineers (IPEs) Barney Speckman and Sundar Venkataraman.

Acronyms and Abbreviations

ADMS: Advanced distribution management system

BESS: Battery energy storage system

CAISO: California Independent System Operator

CARE: California Alternate Rates for Energy

CDO: Candidate deferral opportunity

CEC: California Energy Commission

CPUC: California Public Utilities Commission

DDOR: Distribution Deferral Opportunity Report

DER: Distributed energy resource

DERMS: Distributed energy resource management system

DIDF: Distribution Investment Deferral Framework

DPAG: Distribution Planning Advisory Group

DPP: Distribution Planning Process

EE: Energy efficiency

EV: Electric vehicle

GNA: Grid Needs Assessment

GPI: Green Power Institute

GRC: General Rate Case

IE: Independent Evaluator

IEPR: Integrated Energy Policy Report

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IOU: Investor-owned utility

IPE: Independent Professional Engineer

LGP: Load growth project

LMDR: Load-modifying demand response

LNBA: Locational net benefits analysis

OIR: Order Instituting Rulemaking

PAO: Public Advocates Office

PG&E: Pacific Gas and Electric

PV: Photovoltaics

RCP: Representative Concentration Pathways

SCADA: Supervisory control and data acquisition

SCE: Southern California Edison

SDG&E: San Diego Gas & Electric

SIOWG: Smart Inverter Operationalization Working Group

TMY: Typical meteorological year

TPP: Transmission planning process

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Introduction and Executive Summary

In July 2021, the California Public Utilities Commission (CPUC) initiated the *Order Instituting Rulemaking to Modernize the Electric Grid for a High Distribution Energy Resource Future (*Rulemaking 21-06-017, or the High DER proceeding)[1] to prepare the grid for a high number of distributed energy resources (DERs), including those specific to transportation electrification. This report evaluates the Distribution Investment Deferral Framework (DIDF) filings prepared by the three investor-owned utilities (IOUs)—Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E)—for the past three years and provides a series of recommendations to be implemented in this DIDF cycle or in future High DER proceeding staff proposals. This is the first in a series of at least three annual reports by Kevala that aim to evaluate and improve the DIDF process and associated IOU analytics and filings. The next report is planned for issuance in the October/November 2023 timeframe following the IOUs' August 2023 DIDF filings.

The central objective of the DIDF is to identify and capture opportunities for DERs to cost-effectively defer or avoid traditional distribution investments (such as substation upgrades) that are planned to mitigate forecast deficiencies of the electric distribution system. The DIDF's first implementation in 2018 has been evaluated and revised after each cycle to improve the process as well as test various process enhancement approaches.

Approach

The analysis in this report identifies overarching, structural considerations of the DIDF to enhance distribution grid planning in a way that addresses the overall value proposition of DERs as an alternative to infrastructure capital investments. To identify and address the findings, Kevala systematically reviewed the confidential Grid Needs Assessments (GNAs) and Distribution Deferral Opportunity Reports (DDORs) and analysis for PG&E, SCE, and SDG&E. Kevala also reviewed the prior year Distribution Planning Advisory Group (DPAG) reports developed by the Independent Professional Engineer (IPE), held conversations with the IPE, attended the 2022 DPAG meetings, and researched distribution planning in other jurisdictions for comparisons to the California process.

In conducting this review, Kevala operated on the assumption that written documentation should clearly and transparently explain each IOU's DIDF process. Kevala did not contact the IOUs to fill gaps or resolve confusion in documentation outside of participating in the DPAG process.

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[1] Proceeding R.21-06-017, opened with an *Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future*, issued on July 2, 2021, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M390/K664/390664433.PDF.

However, Kevala clarified and discussed the methods and findings with the IPE. The IPE has ample experience in the DIDF process by running an annual verification and validation process for the past four DIDF cycles and documenting and discussing the methods and data used in the DIDF cycles with each of the IOUs.

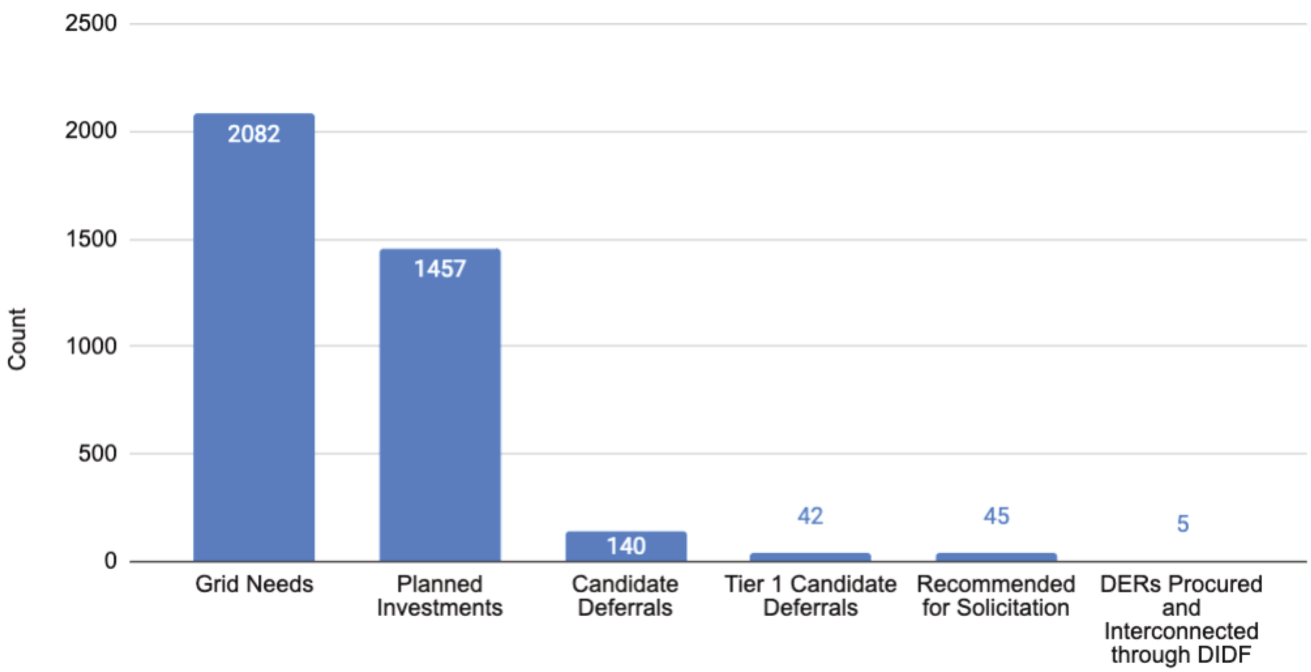
Findings

The grid needs identified by the IOUs pass through multiple stages in the DIDF process to be considered for deferral through DER procurement. For this study, Kevala analyzed the composition of the grid needs as identified in the original filings of PG&E, SCE, and SDG&E for 2020 and 2021, and PG&E and SDG&E for 2022.[2] Figure ES-1 illustrates the grid needs identified in those filings and how the grid needs eligible to be met with DERs declined by stage of the deferral consideration process (or funnel). The Grid Needs and Planned Investment bars in the figure include redundancies identified in multiple years' filings—these redundancies show that, in some cases, **there are multiple opportunities to consider deferrals and yet successful deferrals are exceptionally rare**.

As Figure ES-1 shows, the most impactful transition of the funnel—the transition where most DERs are eliminated from consideration—is the transition from the planned investments stage to the stage where candidate deferrals are identified; 90% of total planned investments are removed from consideration for potential deferral in this stage. A primary driver of this significant reduction in candidate deferrals between these two stages is the mismatch in distribution grid needs planning and DER eligibility time horizons: grid needs and planned investments are mostly identified in the short term by the IOUs (year 3 or before), while candidate DER deferrals are only eligible to defer grid needs that are four or more years out in the planning horizon.[3]

[2] SCE requested an extension for its 2022 filing to January 2023; as such, Kevala did not include the 2022 GNA results for SCE in this evaluation.
[3] The timing screen is based on the current understanding that approximately three years are needed to complete the procurement and interconnection process for DERs.

Figure ES-1: Total grid needs for all three IOUs for the three DIDF cycles spanning 2020-2022, as funneled through the DIDF process. The count of DERs procured and interconnected through the DIDF process includes three projects under contract and does not include the outcomes of the current 2022 cycle. *(Source: Kevala analysis of IOU GNA and DDOR reports)*



Kevala also found that **known loads are a key trigger of capacity grid needs in the current GNA process**, driving 56% of grid needs for PG&E and 25% for SDG&E in the most recent filings. The term "known loads" is used in general by all three utilities to mean load growth for new or additional load that is based upon customer request for new service[4]. Year-over-year, known loads are frequently identified in the first three years of the forecast horizon, without sufficient time for DER deferral.

- Improved forecasting of where new loads will request interconnection in years 4 and 5 (and beyond) should increase the opportunities for DER distribution deferrals in those years.
- Accelerating the IOUs' DER procurement processes would allow DERs to also defer costlier investments in years 1-3.

Recommendations

Based on these findings (among others), Kevala provides a series of DIDF reform recommendations in this report. The recommendations aim to provide greater transparency and consistency across the PG&E, SCE, and SDG&E GNA and DDOR filings. Specifically, these

[4] Resource Innovations, *2022 Independent Professional Engineer Post DPAG Report*, submitted to CPUC Energy Division, PG&E, SCE, and SDG&E, 2022.

recommendations focus on improving definitions, data, and metrics. Kevala's key DIDF reform recommendations include the following:

- **Resolve the conflation of resiliency with microgrid as a grid deficiency category** by changing the definition of microgrid/resiliency to a category that identifies grid needs and planned investments to improve resiliency that are not necessarily related to a microgrid project. The category should include a clear definition of resiliency for grid infrastructure needs.
- **Report on net-load forecast error metrics in the GNA.** Add a five-year historical comparison in the GNA comparing the previous GNA year's net-load forecast to the current year weather normalized peak load. Understanding historical load and DER growth and performance can provide insights into the potential of DERs to reduce peak load and risk as a viable option. It also enables the IOUs to identify for which types of feeders or banks the current forecast and disaggregation methods might be performing best and to identify the feeders or banks where improved methods might be needed.
- **Report whether feeders or banks are in a disadvantaged community** and report on the percentage of customers with an electricity burden greater than 5%; if utilities do not have such data, Kevala recommends identifying feeders or banks serving a significant number of customers on a California Alternate Rates for Energy (CARE) rate.[5]
- **IOUs to identify CDOs that could be procured in year 3 or before for discussion during the DPAG review process.** Now that DDOR Request for Offer and Standard Offer Contract procurement processes launch in September of the DIDF cycle, utilities should identify planned investments in year 3 or earlier that are possible candidates for deferral based on new criteria such as small capacity projects or low growth rate areas. IOUs will discuss these projects in the DPAG, and DER developers and aggregators can provide feedback and comments on the feasibility of procuring solutions in year 3 or before.

Kevala held an informational webinar on September 27, 2022 to present the scope of this report to DIDF stakeholders and received 48 questions and comments from IOUs and stakeholders, including PG&E, SDG&E, the Public Advocates Office (PAO), and the Green Power Institute (GPI). Appendix 1 summarizes responses to the informal stakeholder comments provided on September 27, 2022. Appendix 2 provides additional findings from the analysis. The additional findings relate to distribution planning process improvements Kevala identified for potential consideration in future staff proposals that will address the scoping questions for High DER Proceeding Track 1.

[5] California Public Utilities Commission, "California Alternate Rates for Energy," https://www.cpuc.ca.gov/consumer-support/financial-assistance-savings-and-discounts/california-alternate-rates-for-energy.

This report is broken into three sections:

- DIDF Filing Findings and Observations: Presents an analysis of the historical 2020-2021 DIDF[6] and current 2022 DIDF fillings[7] for the three IOUs—PG&E, SCE, and SDG&E—to understand key trends and challenges in the DIDF process.
- DIDF Reform Recommendations: Covers the DIDF reform recommendations identified based on Kevala's analysis.
- Conclusions and Next Steps: Discusses Kevala's conclusions and next steps, including how the results may influence future work related to the High DER proceeding, including staff proposals.

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[6] Kevala did not receive full GNA/DDOR documentation for all three IOUs for 2019, so the team focused the overarching analysis on the 2020-2022 filings. Kevala did receive some 2019 data files and included those where possible.

[7] SCE requested an extension for its 2022 filing to January 2023; as such, Kevala did not include the 2022 GNA results for SCE in this evaluation.

DIDF Filing Findings and Observations

Kevala analyzed the 2019–2021 historical GNA/DDORs and the current 2022 GNA/DDORs for the three IOUs (PG&E, SCE, and SDG&E) to understand key trends and challenges in the DIDF process.[8] The grid needs identified by the IOUs pass through multiple stages in the DIDF process to be considered for deferral through DER procurement. These stages amount to a severe funnel that excludes almost all potential grid needs, through one criterion or another, from being deferred with DERs.

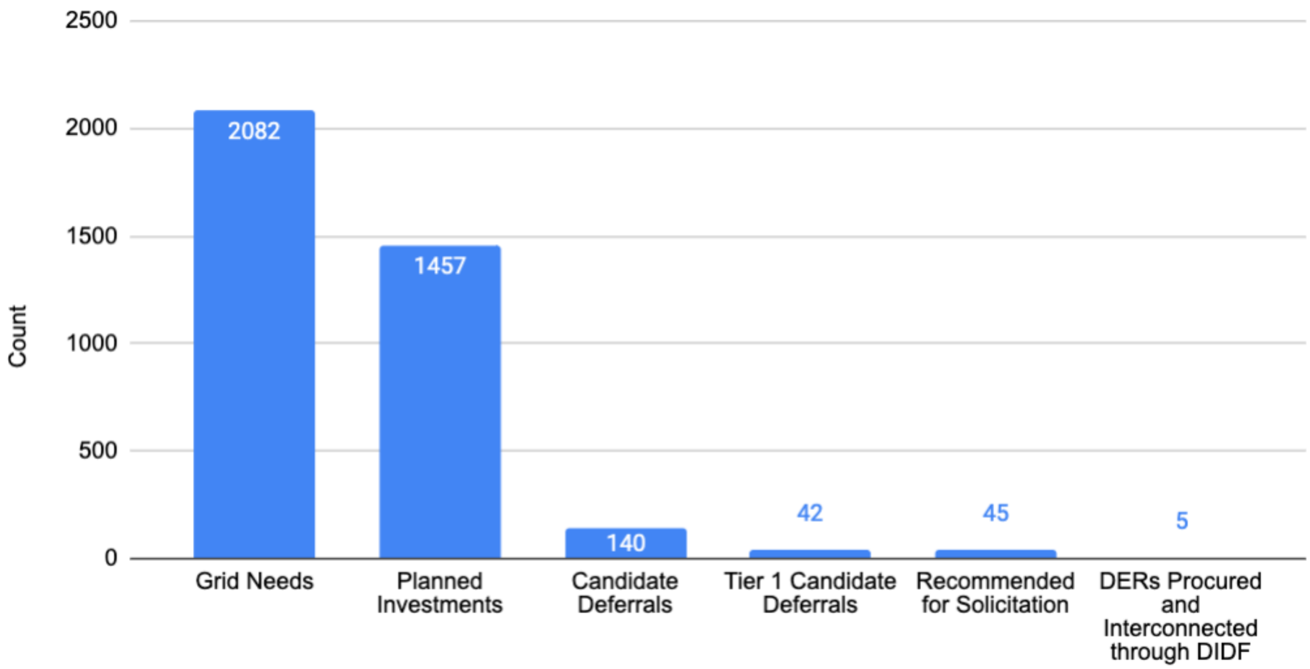
Figure 1 illustrates these stages for the grid needs identified in the original filings of all three IOUs from 2020 to 2022 and how the grid needs that were eligible to be met with DERs declined by stage. Grid needs are first identified in the GNA before being mapped to planned investments in the DDOR (multiple grid needs can be addressed through a single planned investment). The Grid Needs and Planned Investment columns in the figure include redundancies identified in multiple years' filings. These redundancies show that, in some cases, there are multiple opportunities to consider deferrals and yet successful deferrals are exceptionally rare.

As Figure 1 shows, the most impactful stage of the funnel is identifying candidate deferrals from the planned investments; 90% of total planned investments are removed from consideration for potential deferral in this stage, namely due to the three-year timing screen. One potential reason for this significant reduction in candidate deferrals between these two stages is that the grid needs and planned investments are mostly identified in the short term (year 3 or before), while candidate DER deferrals are only eligible to defer grid needs that are four or more years out in the planning horizon.[9]

[8] SCE requested an extension for its 2022 filing to January 2023; as such, Kevala did not include the 2022 GNA results for SCE in this evaluation.

[9] The timing screen is based on the current understanding that approximately three years are needed to complete the procurement and interconnection process for DERs.

Figure 1: Total grid needs for all three IOUs for the three DIDF cycles spanning 2020-2022, as funneled through the DIDF process.[10] The count of DERs procured and interconnected through the DIDF process includes three projects under contract and does not include the outcomes of the current 2022 cycle. *(Source: Kevala analysis of IOU GNA and DDOR reports)*



The timing screen is based on the current understanding that approximately three years are needed to complete the procurement and interconnection process for DERs. The outsized impact of the three-year timing screen begs two questions:

1. How well are utilities forecasting their needs in years 4 and 5 of the planning horizon?
2. Can the timing screen be reconsidered or relaxed, or can a playbook of common DER solutions be developed to reduce procurement time?

Question 2 is an area for further consideration by DIDF stakeholders, while Question 1 is a key focus of the analysis that follows.

Candidate deferrals are further funneled through a prioritization process that eliminates 75% of them by design. The intention is that these Tier 1 candidate deferrals will be recommended for solicitation. However, only two DERs have been successfully procured and interconnected: two

[10] A few more candidate deferrals are recommended for solicitation than achieved Tier 1 status due to requirements that the IOUs submit a certain number of projects for solicitation, even in cases where they do not identify enough Tier 1 candidate deferrals.

large batteries implemented by SCE at Elizabeth Lake. PGE is also procuring three battery systems from the 2021 DIDF cycle.[11]

Kevala's evaluation focuses on analysis and recommendations for the overall DIDF process and the current grid needs forecasting and identification methods; a review of the solicitation process itself is left for future analysis.

Grid Needs Triggers

- **Known loads are a key trigger of grid needs in the current GNA process.**
- **The 2022 GNA light-duty electric vehicle (EV) disaggregated Integrated Energy Policy Report (IEPR) forecast does not trigger any feeder upgrades for PG&E and SDG&E over the next 5 years.**

Based on the outsized impact of the timing screen (as identified previously in the funnel of stages), Kevala investigated two major questions by analyzing the IOUs' GNA/DDORs and supporting documentation:

- **What are the main factors that trigger a grid need?** Are they the DER load growth (electrification), new interconnections (known loads), or economic load growth? Furthermore, how many capacity constraints have been mitigated by peak-demand and energy-reducing DERs such as photovoltaics (PV), energy efficiency (EE), load-modifying demand response (LMDR), and energy storage?
- **Are those triggers being identified in time to enable deferral through the DIDF process?** Given the current three-year timing screen, how are forecasting methods working beyond the three-year timeframe? How is the timing screen impacting the DIDF pipeline?

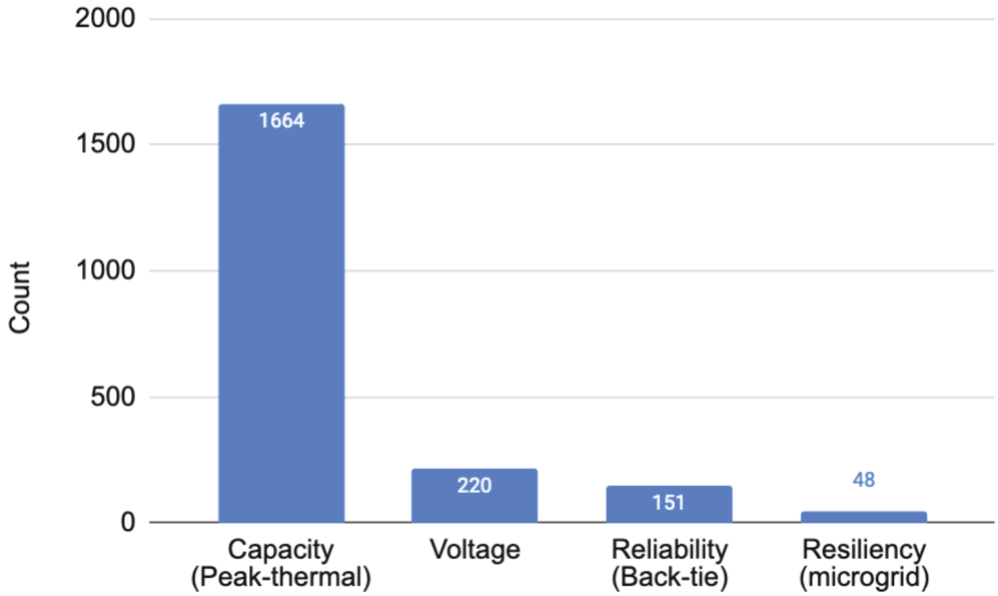
The DIDF process is intended to consider and potentially defer four types of grid needs:

- Capacity or thermal
- Voltage
- Reliability (back-tie)
- Resiliency (microgrid)

The vast majority of identified grid needs in 2020–2022 have been capacity (see Figure 2). While some of Kevala's recommendations discuss identifying methods for these four categories, the analysis here focuses on triggers for capacity grid needs.

[11] Local Battery Energy Storage Systems Serve as a Cost-Effective, Engineered Solution to Meet Electric Grid Needs - PGE Currents

Figure 2: Total grid needs identified by PG&E (filing years 2020-2022), SDG&E (filing years 2020-2022), and SCE (filing years 2020-2021) by the four deferrable grid needs categories. (*Source: Kevala analysis of IOU GNA and DDOR reports)*



To identify the major triggers of capacity grid needs, Kevala analyzed the confidential GNA feeder listings for facility rating, facility demand (SDG&E includes base and cumulative demand in separate fields),[12] and all DERs. This part of the analysis was limited to:

- The 2022 GNA filings from PG&E and SDG&E (SCE requested an extension for its 2022 filing to January 2023).
- Feeders, because known load relationships are provided to a feeder by the IOUs and not a more granular interconnection point (e.g., line section or service transformer).

Future studies should consider analyzing line segments and substation banks. One recommendation from the PAO suggested that focusing on line segments with DERs could help mitigate future upstream grid needs, which should be explored in the future High DER proceeding activities.

Currently, the IOUs identify capacity grid needs when forecast net demand exceeds 100% of a facility's rating.[13] The IOUs have two primary sources for generating net load forecasts: the California Energy Commission's (CEC's) IEPR forecast and their own known loads lists. The CEC

[12] The IOUs do not clearly differentiate between known loads and economic growth or the difference between known loads and the California Energy Commission's (CEC's) IEPR forecast. Therefore, Kevala does not differentiate in this analysis.
[13] There may be other expectations that are not clearly identified in the GNAs.

IEPR[14] demand forecast goal is to develop annual end-use consumption-level forecasts by customer sector and planning area. The IEPR forecast is also broken down into components including load-decreasing DERs (EE, PV and BESS) and load-increasing DERs (EVs).[15]

The IOUs also have some insights into the local demand changes for the short term via service requests for new connections (and disconnections). The new connections are called known loads or load growth projects (LGPs). By breaking down the forecasted net demand into its component parts, in many cases, IOUs can identify the component that triggers a capacity grid need.

To identify the triggers of GNA capacity grid needs, Kevala individually removed the contributing components from the facility demand value to identify what might trigger the demand to exceed 100% of the rating. Kevala conducted this analysis using the PG&E and SDG&E 2022 GNA filings looking at the forecast year 2026 to analyze the causes of all capacity grid needs triggered between 2022 and 2026. The following are the steps used to identify the trigger for a given capacity grid need:

1. Identify 2026 facility demand
2. Aggregate the 2026 load-reducing DERs (EE, PV and BESS)
3. Aggregate the 2026 load-increasing DERs (EVs)
4. Aggregate the 2022-2026 known loads[16]
5. Subtract out each item from the facility net-load individually: load-reducing DERs, load-increasing DERs, and known load projects by feeder. Subtract out combined known loads and increasing DERs to identify impacts of econometric load growth.

Table 1 provides the results of Kevala's analysis and identifies the number of feeders affected by the different items and that will exceed 100% of facility rating by 2026.[17] **Known load growth is the key component that triggers a capacity grid need** for over half of PG&E's forecasted capacity grid needs and one of SDG&E's four capacity grid needs. No needs were triggered by increasing DERs (EVs) from the IEPR forecast alone, and none were triggered by the combination of known loads and base load growth from the IEPR forecast. Through process of elimination, the remainder of the capacity grid needs that could not be directly attributed to one of the trigger

[14] California Energy Commission, *Final 2021 Integrated Energy Policy Report, Volume IV: California Energy Demand Forecast*, February 2022, https://efiling.energy.ca.gov/GetDocument.aspx?tn=241581&DocumentContentId=75546.
[15] PG&E only uses the light-duty IEPR EV forecast, not medium or heavy duty.
[16] Kevala used the value provided in the Known Loads Projects tracking data provided by the IOUs in the DIDF 2022 documentation.
[17] These grid needs are identified by their 2026 forecast regardless of the year-of-need reported in the GNA (i.e., cumulative needs over the forecast horizon).

categories are understood by Kevala to be triggered by weather normalization of the 2021 peak load plus load growth to 2026 from the IEPR forecast. Given that known loads are such a significant trigger of capacity grid needs, the next section investigates how well these needs are being anticipated by the current GNA forecasting process.

Table 1: Triggers of forecast 2026 capacity grid needs at the feeder level *(Source: Kevala analysis of 2022 PG&E and SDG&E grid needs data)*

	PG&E		SDG&E	
	Count	**%**	**Count**	**%**
Total 2026 capacity grid needs (feeders only)	269	N/A	4	N/A
Capacity grid need trigger:				
Known loads (including non-residential electric vehicle supply equipment*)	150	56%	1	25%
Increasing DERs from the IEPR (light-duty EVs only)	0	0%	0	0%
Combination of known loads + base load growth + EVs	0	0%	0	0%
Remainder: Weather normalized 2021 peak load + IEPR load growth	119	44%	3	75%

Note: SCE requested an extension for its 2022 GNA/DDOR filings to January 2023, as such, 2022 GNA results for SCE are not included in this evaluation.

*It is unclear how much each IOU splits its EV charging loads. SCE explicitly states in step 1 of the GNA analysis that it removes the transportation electrification from the IEPR forecast and then backs in its own analysis.

Known Load and IEPR Load Forecasting

Known loads are a key driver of capacity grid needs and their impact on grid needs and planned investments for years 1-3 repeat year after year.

Given that Kevala identified known loads as a major trigger of capacity grid needs, this section investigates trends in the IOUs' known loads data, the relationship between known loads and the IEPR forecast, and correlation with the DIDF timing screen. As Figure 3 through Figure 5 illustrate, all three IOUs historical known loads lists are front-loaded and tend to predict the most load increases in the current year regardless of the year of the GNA filing. While PG&E has some variability, it is evident for SCE and SDG&E that most known loads are anticipated to be interconnected in the next three years following any given GNA filing date. While this short timeframe is to be expected given these lists are compiled from customer requests, it is a challenge for the DIDF forecasting process as the concentration of known loads in the first three years directly overlaps with the three-year DDOR timing screen.

Figure 3: PG&E known loads forecast over the years of the forecast horizon for each of the four filings from 2019 to 2022 *(Source: Kevala analysis of IOU-provided known loads by year)*

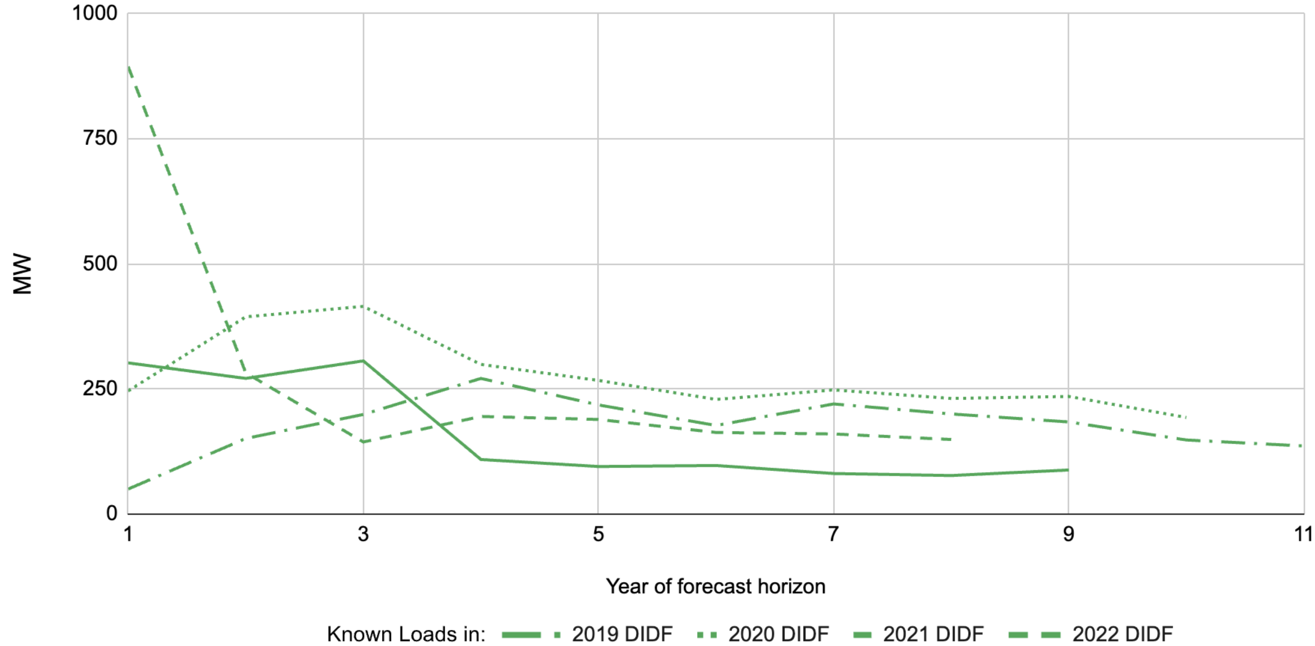


Figure 4: SCE known loads forecast over the years of the forecast horizon for each of the three filings from 2020 to 2022. *(Source: Kevala analysis of IOU-provided known loads by year)*

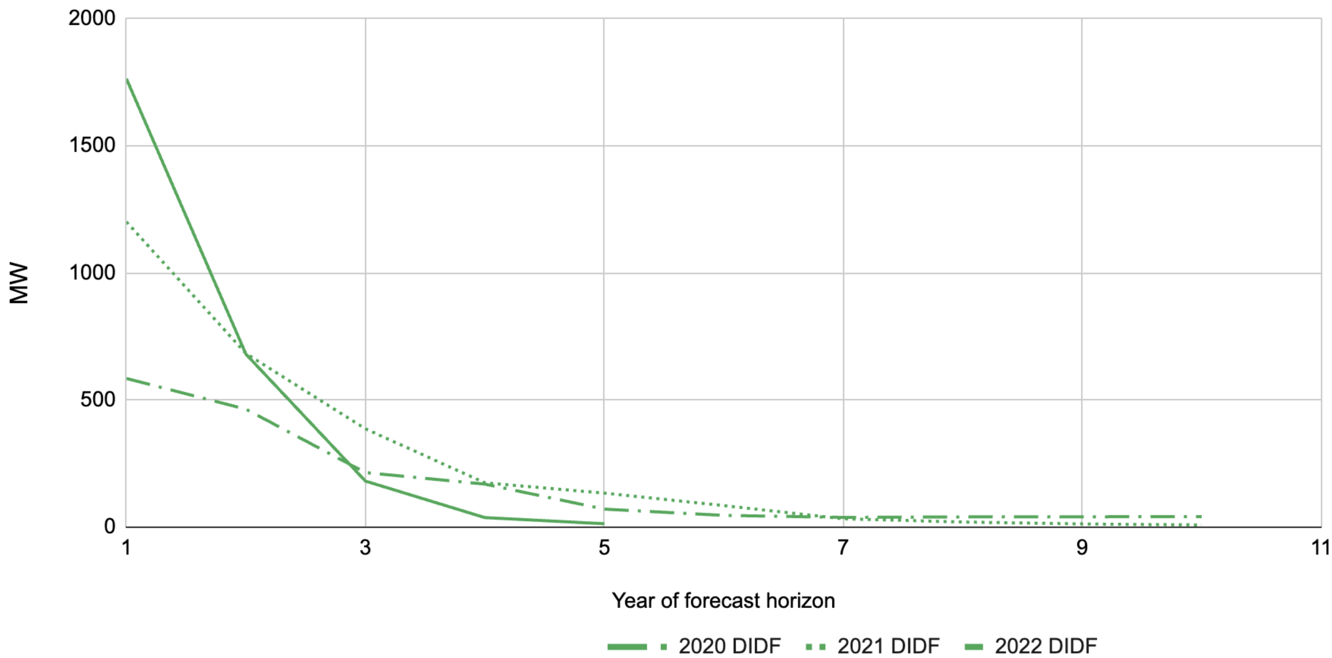
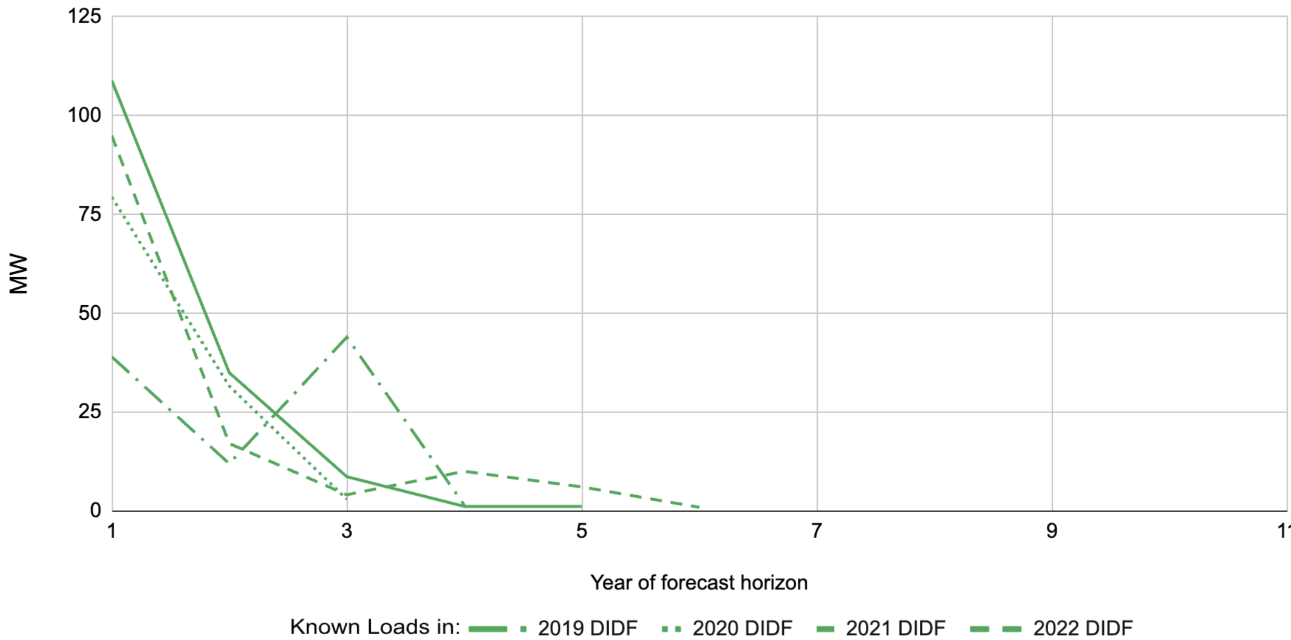


Figure 5: SDG&E known loads forecast over the years of the forecast horizon for each of the four filings from 2019 to 2022 *(Source: Kevala analysis of IOU-provided known loads by year)*



Because the known loads lists are not reliably providing sufficient information about upcoming capacity grid needs in years 4 and 5 (after the timing screen) of the forecasting horizon, the follow-on questions are:

- How do these known loads compare to the IEPR forecast?
- Is the IEPR forecast providing sufficient information to conduct the GNA for years 4 and 5?

The IEPR forecast is a top-down, system-level forecast, so the load growth forecasts need to be merged. The IOUs use their own known load growth projections at a feeder level and apply the disaggregated IEPR load forecast to result in the same cumulative growth as the IEPR at the end of the period (except for SCE).[18]

Figure 6 shows an example of this: the known loads and IEPR forecast reconciliation for PG&E from the 2022 IPE Post DPAG Report. In the first few years of the forecast horizon, the known loads vastly outpace the IEPR forecast. While PG&E is shown here, the trend is similar for SDG&E and SCE. The IEPR forecast does not consider the IOU-provided data of known load growth and

[18] While SCE developed a known load forecast using similar descriptors as PG&E and SDG&E regarding known loads and embedded known loads (referred to as the economic forecast) in that the load growth is based on historical data and other indicators known by the CEC, SCE identified incremental known loads for forecasts in addition to the load growth forecasted in the CEC IEPR forecast; these loads were identified from new loads not historically tracked or forecasted in the IEPR (see the 2022 IPE Post DPAG report).

has historically used its own analysis.[19] Because the IEPR forecast projects changes in consumption[20] using historical data and market indicators, it is unclear how much of load growth is fully reflected in base load or incremental growth such as cultivation, EV supercharging, and temporary loads as these are relatively new load types.

Figure 6: Annual PG&E known load growth, economic load growth, and IEPR forecast from 2021 filing *(Source: 2022 IPE Post DPAG Report)*

There are key differences in perspective between the system-level IEPR forecast and the needs of the distribution planning process. The IEPR forecast is energy-based, while distribution planning focuses on the capacity to serve peak demands. In addition to under-characterizing new load types (cultivation, EV charging), another potential source of discrepancy is that load decreases in some locations are being obscured by even greater load increases in other locations with the

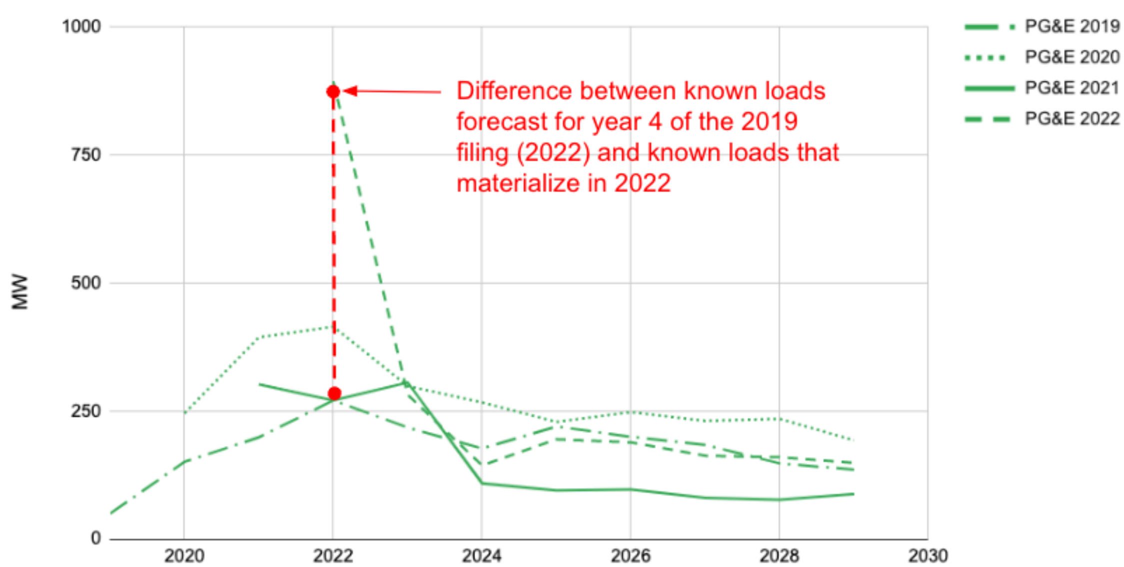
[19] The CEC load forecast has gradually improved over the years. An American Council for an Energy-Efficient Economy paper from 2020 shows how the previous electricity use forecasting models over-predicted electricity usage by approximately 10% in the final year of its forecast prior to EE integration. The average load growth rate decreases by an average of 50% when integrating long-term EE.
https://www.aceee.org/files/proceedings/2020/event-data/bio/YW11bC5zYXRoZUBuYXZpZ2FudC5jb20%3D#:~:text=your%20electricity%20forecast!-,picture_as_pdf,-This%20Digital%20Conference

[20] The CEC forecasts consumption and then applies IOU, sector, and end-use load profiles to determine the peak load forecast.

system-level forecast. Localized load decreases due to EE, PV, load management, and demographic and economic change are not typically concerns for distribution planning—at least until local generation reaches levels where overvoltage violations, PV backfeeding, and impacts to local protection schemes become concerns. While the IEPR does attempt to include load-reducing DERs, it is difficult to get sufficient data to ensure validation of load decreases, and it is possible these are being under-characterized. Using only the change in system load to forecast local load increases underestimates the total impacts on the distribution system because the load decreases in some locations obscure load increases in other locations when viewed from the system level.

The IOUs' current methods for adjusting their load forecasts to match the IEPR forecast after the last date (~two–three years) in their known load schedule is underestimating the actual known loads requests that will be on the docket in the next few years, which has led to a series of missed opportunities. For example, Figure 7 and Figure 8 illustrate PG&E's and SDG&E's[21] known loads lists from the last four DIDF cycles, this time aligned by year of need instead of the forecast horizon. In 2019, PG&E forecasted its 2022 known loads would be 271 MW; by 2022, its known loads for that year had increased by over 500 MW to 894 MW. In 2019, any grid needs associated with the 2022 known loads were in year 4 of the forecast horizon and would have passed the DDOR timing screen. A similar trend is seen with SDG&E.

Figure 7: PG&E known loads forecast by GNA filing year *(Source: Kevala analysis of IOU-provided known loads by year)*



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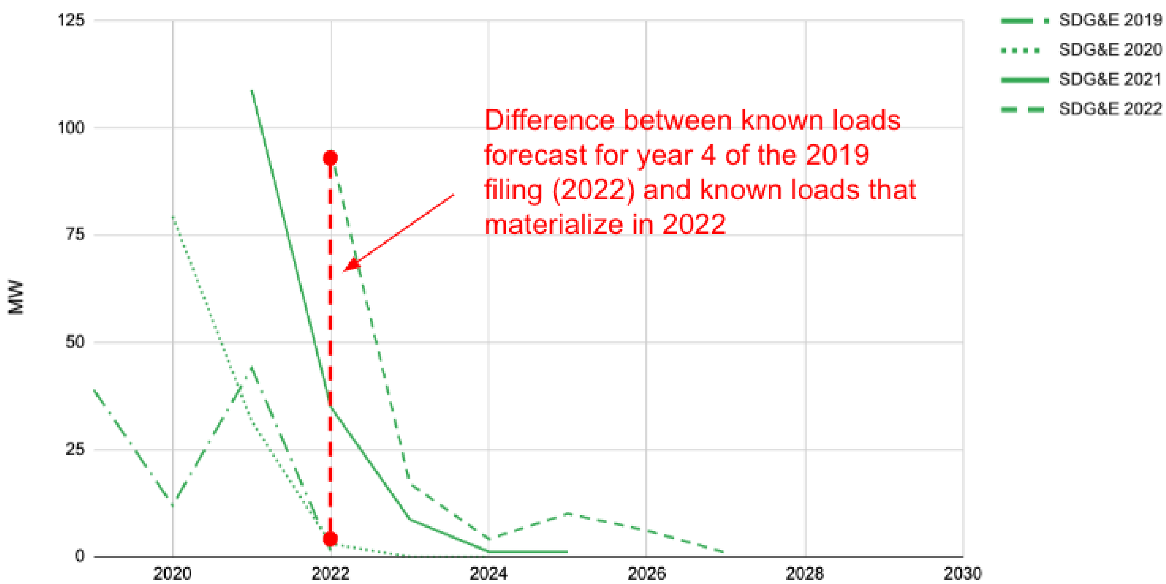
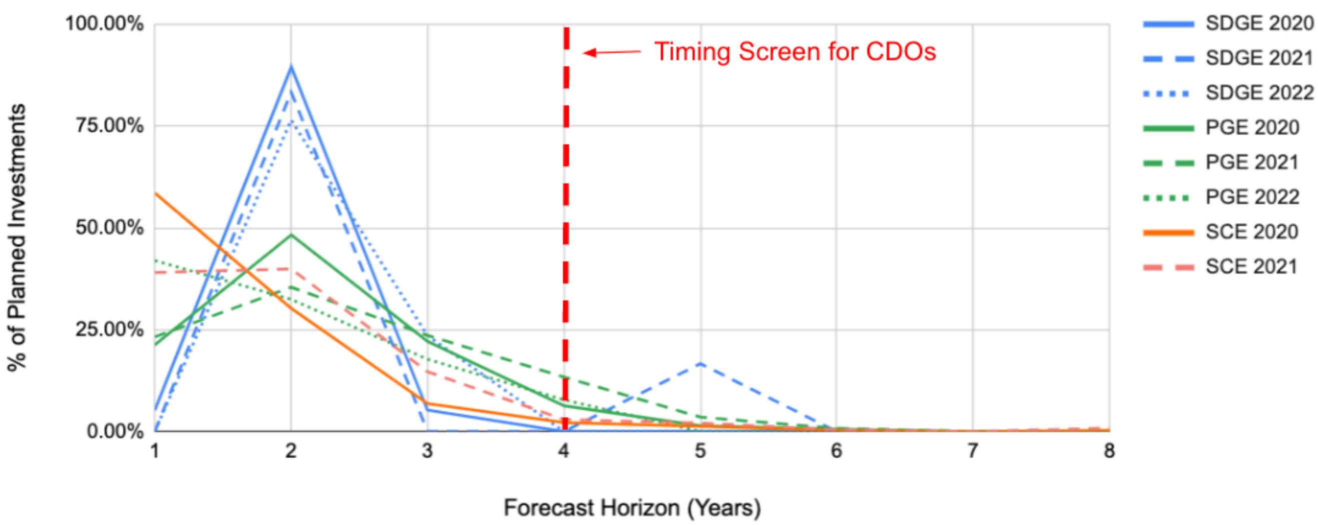
[21] Kevala did not include SCE for this comparison because it did not receive SCE's 2019 known loads list.

Figure 8: SDG&E known loads forecast by GNA filing year *(Source: Kevala analysis of IOU-provided known loads by year)*



In each cycle, IOUs identify most grid needs based on the known loads list, which is concentrated in the first three years. Therefore, most grid needs and their corresponding planned investments fall within the first three years, as Figure 9 illustrates. These planned investments are automatically excluded from deferral by the three-year timing screen, leading to the funnel result in Figure 2.

Figure 9: Number of planned investments by year of need (forecast horizon) for each GNA year *(Source: Kevala)*



Given the direct correlation of the number of capacity grid needs identified to the known loads forecasted, there needs to be an adjustment method to ensure an appropriate forecast in the long term (after year 3). This is an area for coordination with the CEC to improve the IEPR forecast and how it is disaggregated to the local level. This is also an area where the IOUs can develop new local load forecasting techniques that focus on the needs of distribution planning rather than relying solely on the top-down, consumption-based forecast. The IPE has similarly identified the known loads forecasting process as an area for improvement, and the 2022 IPE Post DPAG report[22] outlines the differences in the known load analysis by IOU and provides recommendations. Kevala agrees with these recommendations and summarizes them here:[23]

- Increase coordination between the CEC and IOUs to account for the incremental known load projects in future IEPR forecasts to ensure that the CEC incorporates the new load types.
- Discount the known loads forecast, like PG&E's approach, to reflect that some customer requests may be delayed, reduced, or canceled. PG&E averages the LGP for the first three years and then uses the average for year 1, 90% for year 2, and 80% for year 3.
- Implement an up-to-date known load project database that is shared with the CEC to facilitate a review of forecasting accuracy. The intent is to understand and track whether specific LGPs materialize by using a unique project identification number, circuit name, initial request, load amount, and expected and actual online date.
- Document known load projects related to transportation electrification and handle separately to incorporate in an EV (DER) load adjustment versus a part of known loads.

The IPE has also recommended a database of new service requests updated as data changes in regard to service date forecast changes or actual connection date. This request is to incorporate the SCE incremental forecast considerations, increase transparency for the CEC IEPR and the GNAs, and provide data for analytics.

[22] Resource Innovations, *2022 Independent Professional Engineer Post DPAG Report*, submitted to CPUC Energy Division, PG&E, SCE, and SDG&E, 2022.
[23] GPI provided a similar recommendation in the comments to identify the best way to forecast known loads and to uniformly treat known loads across the IOUs.

Forecast Certainty and Timing

- **Forecast uncertainty of load growth and DERs is not proactively considered.**
- **DERs are effective at reducing peak load.**
- **Needs are identified but not addressed and then the timing screen excludes them.**

The current forecasting methods do not proactively account for forecast uncertainty. All three IOUs use a single scenario forecast based on their known loads lists and a single IEPR scenario. Rather than ingraining forecast uncertainty in the GNA method, it is addressed in an exclusionary post-processing step through the forecast certainty screen. Two paths reduce this challenge for the DIDF process:

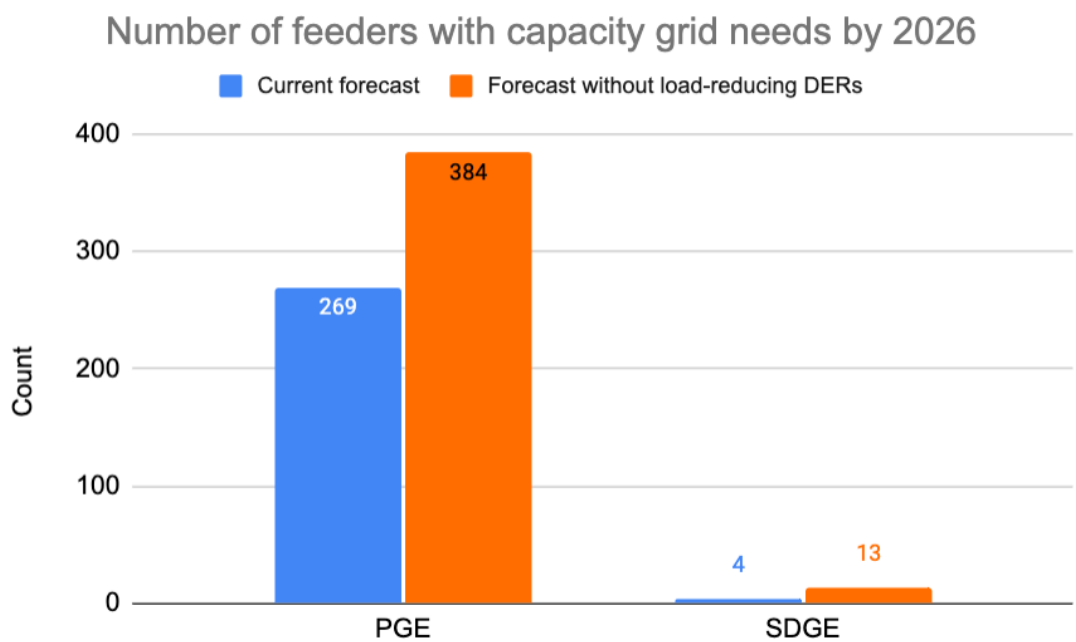
1. Developing workarounds to shorten the time to procurement and thus the timing screen to enable more confident decision-making based on the known loads lists
2. Improving how uncertainty and risk are proactively included in the GNA forecast, particularly for year 4 on.

Forecast uncertainty is also an area of concern for the IOUs, which have expressed anxiety about making deferral decisions based on midterm (3+-year) forecasts. For example, many LGPs are not known to a level of certainty that registers by the IOU as a known load. Stakeholders expressed concern that the IOUs may discount certain locations intentionally or not via the disaggregation process of where load growth is likely to appear. For example, in PG&E's forecast certainty screen, the IOU is flagging feeders with many load inquiries as areas with high uncertainty that seem to de-prioritize candidate deferrals. However, these areas with high customer interest can become prime candidates for DER deployments if they can be identified with sufficient lead time.

To incorporate uncertainty into the GNA process, a scenario-based approach is a natural first step; this approach should include demand *and* DER uncertainty. As part of the capacity grid needs to trigger analysis discussed previously, Kevala compared the IOUs' feeder-level capacity grid needs in 2026 to their needs if the IEPR-forecasted PV, EE, LMDR, and battery energy storage systems (BESS) were not included in the GNA forecast. Figure 10 demonstrates that without these load-reducing DERs, PG&E would have **1.4 times** the number of feeders requiring capacity upgrades over the next 5 years, while SDG&E would have **3.3 times** as many.[24]

[24] Kevala omitted SCE due to the delay in its 2022 GNA filing.

Figure 10: Number of feeders with capacity grid needs by 2026 using the current forecast compared to the number of needs if load-reducing DERs (PV, EE, LMDR, BESS) do not materialize. *(Source: Kevala based on IOU-provided GNA data)*



Not only does this speak to the value of DERs in deferring capital investments, but that the risk these customer-owned DERs do not materialize in the locations the IOUs have assigned them to is not considered at all in the current forecast uncertainty method. This is a function of forecast uncertainty in the overall adoption rate and how the current top-down IEPR forecast is allocated or disaggregated to the substation, feeder, and line segment level. The adequacy of the process to distribute DERs to each feeder is critical, either through the top-down allocation process or a bottom-up adoption analysis.

Finally, an analysis of the previous years' GNA/DDORs identified 34 feeders in PG&E territory that have a capacity demand need, first identified in 2019, that still has a need in 2026 (exceeding 100% of facility rating) and were not included in the 2019 DDOR. While additional analysis of these feeders is needed to confirm their current status, this speaks to the challenges of forecast certainty and decision-making in the current DIDF process. Needs can be identified year-over-year but not addressed. There is a short window where the IOUs have reasonable confidence in the current forecast to act but before they are excluded by the timing screen. Addressing both of these issues—forecast uncertainty and restrictions of the timing screen—is needed to facilitate a significant expansion of successful deferrals through the DIDF process.

DIDF Reform Recommendations

This section presents recommendations for modifying the DIDF process in the current DIDF reform cycle. Table 2 summarizes issues identified with the current process and Kevala's suggested recommendations for consideration in the annual DIDF reform process. These recommendations are organized into three main categories:

A. **General DIDF Improvements:** This category groups the policy and structural recommendations targeted to improve the outcomes of the DIDF process.
B. **DIDF Accuracy Improvements:** This category includes suggestions related to improving the accuracy of load and DER forecasting to proactively determine grid needs and identify candidate deferral opportunities.
C. **DER Integration and Value Streams:** This category groups the recommendations related to best practices in DER grid integration to maximize the cost-effectiveness of integrating DERs into the power system while maintaining or increasing system reliability.

Table 2: DIDF reform process recommendations by category and topic area *(Source: Kevala)*

Category	#	Issue Identified	Kevala Recommendations
A. General DIDF Improvements	1	IOUs do not provide sufficient information for stakeholders to have a full and transparent understanding of the methods used to evaluate grid needs.	**Provide documentation for full transparency of DIDF analysis methods.** To facilitate a due diligence review of grid planning investments, the derivation of the grid needs and planned investments must be transparent and replicable by third parties. For example: ● *Feeder-level known loads:* Provide full transparency into the known load categories, modeling, and impact on grid needs identification. Provide line-section or service transformer point of interconnection. ● *Weather normalization:* Provide specific details on calculating the 1-in-10 forecast versus the high level method with gaps that is provided now. ● *Non-weather sensitive feeders:* Define the criteria for determining appropriate independent variables for assessing if the load is weather sensitive or not and for describing the methodology used for calculating the 1-in-10 for non-weather sensitive grid assets. ● *Voltage studies:* Provide a full description of how the IOUs perform power flow studies to evaluate grid needs, including a description of how the transformer banks and feeders are modeled, how load-tap changer controls are modeled, how load allocation is performed, what time-steps are evaluated, and how DERs are modeled.
	2	Uncertain disaggregation of DER forecasts to banks or feeders could be masking the proactive identification of grid needs.	**Report and flag feeders or banks in the GNA that are at risk of violating the thermal capacity and reliability thresholds and voltage violation criteria if the disaggregated DER forecast does not materialize.** This could enable early identification of feeders and banks for which DERs are effective at reducing peak load and that could be included as candidate deferral opportunities (CDOs).

Category	#	Issue Identified	Kevala Recommendations
	3	Known loads and uncertain disaggregation of load growth to banks or feeders could be identifying grid needs that are at risk of becoming stranded assets.	**Report and flag feeders or banks in the GNA that are at risk of not violating the thermal capacity or reliability thresholds and voltage violation criteria if the disaggregated load growth or known load does not materialize.** This could enable the transparent identification of feeders or banks at risk of having grid needs identified due to load that does not materialize.
	4	The grouping of microgrids and resiliency as a grid needs category leads to a lack of a clear identification method for grid investments that improve resiliency that are not microgrids.	**Resolve the conflation of resiliency with microgrid as a grid deficiency category** by changing the definition of microgrid/resiliency to a category that identifies grid needs and planned investments to improve resiliency that are not necessarily related to a microgrid project. The category should include a clear definition of resiliency for grid infrastructure needs.
B. DIDF Accuracy Improvements	1	Identifying known loads is reactive and not proactive.	**Analyze the correlation and timeline between initial load inquiry or application to quantifying the known loads** in forecasting to proactively capture grid needs. For example, PG&E indicated there are multiple handoffs before an application load request is added to the distribution planning process.
	2	Key information is missing in the GNA table for stakeholders to evaluate grid needs.	**Include additional reporting data points, such as known loads and econometric load growth, in the GNA table.** GNA tables should include the following for each feeder and bank the 1-in-10 adjusted demand by year: • Adjusted known loads (currently in a separate file): Should be the adjusted value used for new load on the feeder or bank (contribution to net-peak load) • Econometric load growth • Base demand for first year of forecast (from SCADA prior to adjusted load due to IEPR inputs for growth and DERs) • Time stamp of measured peak load

Category	#	Issue Identified	Kevala Recommendations
	3	There is no historical track of how well and for which feeders the current net-load forecast and disaggregation methods are performing when compared to actual measured net-load growth and why.	**Report on net-load forecast error metrics in the GNA.** Add a five-year historical comparison in the GNA comparing the previous GNA year's net-load forecast to the current year weather normalized peak load. Understanding historical load and DER growth and performance can provide insights into the potential of DERs to reduce peak load and risk as a viable option. It also enables the IOUs to identify for which types of feeders or banks the current forecast and disaggregation methods might be performing best and to identify the feeders or banks where improved methods might be needed.
	4	There is no benchmarking of how well the disaggregation of PV and BESS matched the interconnection records.	**Report on PV and BESS adoption forecast error metrics in the GNA** by comparing previous years' interconnection records with the disaggregated PV and BESS values by feeder or bank in the GNA. Understanding DER growth and performance can provide insights into the potential of DERs to reduce peak load and risk as a viable option.
	5	There is no information provided on load transfers, which makes it hard for stakeholders to analyze historical GNA data.	**Provide planned load transfers by feeder and bank with date and load amount.** IOUs may have included load transfers in the forecast. Year-over-year demand in the GNA, in some cases, has unexpected increases or decreases, potentially attributed to planned load transfers.
	6	The GNA does not provide additional information on load growth rate by bank or feeder, which could be used to identify CDOs.	**Report on the load growth rate metric in the GNA** to assess low load growth versus high load growth for feeders and banks by comparing the historical change in load year-after-year. The overall net-load growth rate should be broken down into historical increases in demand and decreases due to DERs, in cases where information about DER deployment is available (for example using recent DER interconnection data to estimate impact on net-load).

Category	#	Issue Identified	Kevala Recommendations
	7	The GNA provides no information on equity and energy justice customers served by feeders or banks, which could be used to better understand equity in planned investments and in identifying CDOs.	**Report whether feeders or banks are in a disadvantaged community** and report on the percentage of customers with an energy burden greater than 5%; if utilities do not have such data, Kevala recommends identifying feeders/banks serving a significant number of customers on a CARE rate.
C. DER Integration and Value Streams	1	It is unclear if high-voltage sub-transmission and transmission costs are included when estimating planned investments' project costs.	**Include high-voltage sub-transmission and transmissions costs caused by a grid need when estimating planned investments' project costs for the DDOR.** If high-voltage bus work is required by the DDOR planned investment project, it should be included in the estimate of project costs because it could greatly impact the locational net benefits analysis (LNBA) deferral value.
	2	Grid needs are mainly identified in years 1-3, and CDOs are only considered for years 4 and 5.	**IOUs to identify CDOs that could be procured in year 3 or before for discussion during the DPAG review process.** Now that DDOR Request for Offer and Standard Offer Contract procurement processes launch in September of the DIDF cycle, utilities should identify planned investments in year 3 or earlier that are possible candidates for deferral based on new criteria such as small capacity projects or low growth rate areas. IOUs will discuss these projects in the DPAG, and DER developers and aggregators can provide feedback and comments on the feasibility of procuring solutions in year 3 or before.

General DIDF Improvements

Methods Transparency

Kevala purposely did not engage the IOUs in its review of the GNAs and DDORs. One of the objectives was to be able to follow the analysis steps with only the reports, files, and data shared with Kevala from the IPE. There are still question marks in the analysis because some of the steps are not fully documented or replicable with the information provided.

One example of this issue is in calculating the 1-in-10 load forecast, which is used to pressure stress the forecast for grid needs in an uncertain future. For the three IOUs, the adjustment is based on temperature. There was little discussion, if any, on what method or adjustments to peak load are performed for the non-weather sensitive feeders, except that the historical load is adjusted for the 1-in-2 and 1-in-10 forecast. The IOUs do incorporate other factors, but little information was provided, if any, about other independent variables for the baseline load adjustment (e.g., demographic and socioeconomic data). Each IOU normalizes historical load data to a 1-in-2 (average or 50th percentile year) prior to generating the 1-in-10 load forecast. Calculating the average year load ensures the prior year is normalized in case it was an outlier weather year. This provides an average year as the starting point for generating the 1-in-10 forecast. Each IOU has its own method for the analysis; Table 3 summarizes the differences.

Table 3: Weather adjustments methodology by IOU *(Source: IOU and IPE reports)*

IOU	1-in-2	1-in-10
PG&E	• Use peak load values for June through September. • If temperature-sensitive, calculate the average or median of the 30 years of peak data. • If not temperature-sensitive, use recent historical data with no adjustments.	• Uses the “Annual Circuit Peak Forecasting” in LoadSEER, which is a regression analysis of annual circuit peak load versus temperature. • LoadSEER calculates weather statistics for each weather station by finding the max temperature per year (i.e., 30 values) and then calculating the temperature-adjusted load.

IOU	1-in-2	1-in-10
SCE	● Use typical meteorological year (TMY) to generate normalized (1-in-2) temperature data for forecasting future load. ● Actual historical weather is used to determine which month is the closest to the 50th percentile. ● Selected month from that year is used in the TMY as the normal weather	● Adjust the normal weather forecast by the design reserve factor based on historical customer behavior in relation to recorded temperature data.
SDG&E	● Use an internal tool to develop 1-in-2 weather-adjusted peak load for each circuit. ● Use the average daily maximum temperature and weighted average cooling degree days gathered over the last 16 years for this calculation.	● Same as PG&E.

IOUs should provide information and methods for when baseline adjustments include non-weather sensitive independent variables such as demographic or econometric modeling. If assets are deemed non-weather sensitive, they should include a description and regression parameters for baseline adjustments of non-weather sensitive independent variables. For example, PG&E indicated in its 2022 GNA report that "Economic variables and temperature are compared against historic bank and feeder peak loads. With this comparison, the most relevant group of economic variables is selected for each bank and feeder. If there are no variables that have a reasonable fit then a flat, or no growth regression is applied." Which variables and which bank and feeder loads are not specified.[25]

Kevala recognizes there is some documentation of tools such as LoadSEER; however, the lack of transparency minimizes the stakeholder engagement to address the electric grid needs in a high DER future. One possibility for improving transparency is putting workbook links in footnotes in the GNA/DDORs. With increasing DERs and the need to prioritize cost-effective solutions, ideally the IOUs have a transparent, systematic, and replicable analysis for increased awareness of the value of each investment.

[25] PG&E's 2022 Distribution Grid Needs Assessment Report.

Recommendation A.1: Provide documentation for full transparency of DIDF analysis methods. To facilitate a due diligence review of grid planning investments, the derivation of the GNA and the DDOR priority matrix must be transparent and replicable by third parties. For example:

- *Feeder-level known loads*: Provide full transparency into the known load categories, modeling, and impact on grid needs identification.
- *Weather normalization*: Provide specific details on calculating the 1-in-10 forecast versus the high level method with gaps that is provided now.
- *Non-weather sensitive feeders*: Define the criteria for determining appropriate independent variables for assessing if the load is weather sensitive or not and for describing the methodology used for calculating the 1-in-10 for non-weather sensitive grid assets.
- *Voltage studies*: Provide a full description of how the IOUs perform power flow studies to evaluate grid needs, including a description of how the transformer banks and feeders are modeled, how load-tap changer controls are modeled, how load allocation is performed, what time-steps are evaluated, and how DERs are modeled.

Identifying Grid Needs Before Exceeding Constraints

Kevala is concerned that the GNA lists needs that are already known (Table 1 indicates that a high percentage of feeders starting the GNA review cycle for PG&E and SDG&E are overloaded already). The IOUs should further investigate the feeder's historical trends to identify any markers that can foreshadow a pending need. One opportunity would be to identify feeders and banks that are at risk of being overloaded based on the forecast uncertainty of load and DER growth determined in the GNA. This would enable solutions using existing DERs or no/low cost DERs to have sufficient lead time and any anticipated load growth to be offset prior to the feeder or bank becoming a grid need in the short term.

Recommendation A.2: Report and flag feeders or banks in the GNA that are at risk of violating the thermal capacity and reliability thresholds and voltage violation criteria if the disaggregated DER forecast does not materialize. This could enable early identification of feeders and banks for which DERs are effective at reducing peak load and that could be included as candidate deferral opportunities (CDOs).

Recommendation A.3: Report and flag feeders or banks in the GNA that are at risk of not violating the thermal capacity or reliability thresholds and voltage violation criteria if the disaggregated load growth or known load does not materialize. This could enable the transparent identification of feeders or banks at risk of having grid needs identified due to load that does not materialize.

Microgrid (Resiliency) Definition

The grouping of microgrids and resiliency as a grid needs category leads to a lack of a clear identification method for grid investments that improve resiliency that are not microgrids. Some planned grid investments that improve resilience could be deferred by DERs, while a microgrid is not a deferrable category.

Across the IOUs, there is also confusion and inconsistency on the requirements and definitions of the microgrid/resiliency category, especially as it relates to resiliency versus reliability. In some cases, it appears microgrid needs were identified based on work done through other CPUC proceedings, namely the microgrid and wildfire mitigation proceedings.

Within the DIDF process, PG&E is the only utility reporting clear qualitative and quantitative identification methods for microgrids/resiliency. PG&E identified potential microgrids either based on criteria for feeders with more than 6,000 customers or through engineering judgment to provide continuity of service during emergency conditions for vulnerable feeders. In the first case, PG&E identified potential microgrids for feeders where many customers are affected during an outage, and loading on adjacent feeders would make reconfiguration difficult to serve some or all of the affected customers. In the second case, PG&E identified a handful of vulnerable feeders due to local load increases, extended planned maintenance, or emergency bank loss deficiencies.

In contrast, SCE and SDG&E did not report any clear microgrid identification methods specific to the DIDF. In its 2021 GNA, SCE did not document any screening or identification method for a microgrid (resiliency) and did not include the microgrid (resiliency) category in its GNA tables. SDG&E reported four microgrid needs, which refer to microgrids already approved through the Microgrid OIR (Decision 21-12-004) and are redundantly reported here.

SDG&E has requested the removal of the microgrid/resiliency category from the DIDF process due to the ambiguity about the category definition and which DER ownership models are suitable for the DIDF process. GPI commented on the definition and suggested redefining resiliency to accelerate progress toward state goals such as thinking beyond microgrids.

Recommendation A.4: Resolve the conflation of resiliency with microgrid as a grid deficiency category by changing the definition of microgrid/resiliency to a category that identifies grid needs and planned investments to improve resiliency that are not necessarily related to a microgrid project. The category should include a clear definition of resiliency for grid infrastructure needs.

DIDF Accuracy Improvements

Track Information for Improved Local Load Forecasting

Given the IOUs' current forecasting method regularly underestimates load additions in year 4 onwards (when the IOUs are most confident in their ability to procure and interconnect DERs), Kevala recommends investigating improved local load forecasting methods, as opposed to relying solely on the system-wide IEPR forecast. For example, PG&E tracks load inquiries, which are understood to be expressions of interest before completing the formal process to add a load to the known loads list. These load inquiries are used in the forecast certainty screen to flag areas with many inquiries as high uncertainty to *de-prioritize* candidate deferrals. However, by tracking these inquiries—including the location, feeder, date of inquiry, any date or date range of when the load or DER is being considered for interconnection, customer class or industry, load size, DER type and purpose, and any other salient information—these load inquiries can be analyzed for their correlation with following years' known loads lists to generate an improved local load forecasting method, particularly in years 4 and 5 of the forecasting horizon.

It is unknown whether the other two utilities similarly track these load inquiries. However, in the 2022 DPAG report, the IPE recommended that there should be an annual review of which known loads were connected, which were delayed, and which were canceled; this information could be rolled in to improve local load forecasting.

Recommendation B.1: Analyze the correlation and timeline between initial load inquiry or application to quantifying the known loads in forecasting to proactively capture grid needs. For example, PG&E indicated there are multiple handoffs before an application load request is added to the distribution planning process.

GNA Table and Metrics

The existing set of tables provided by the IOUs for the GNAs include a listing of feeder and bank ratings, load, and DER load modifiers. A few other data points are provided. Many of these requirements are prescribed by a series of rulings:

- Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework Process, R.14-08-013, May 7, 2019.
- Administrative Law Judge's Ruling Modifying the DIDF—Filing and Process Requirements, R.14-08-013, May 11, 2020.
- Administrative Law Judge's Ruling on Recommended Reforms for the Distribution Investment Deferral Framework Process, R.14-08-013, June 21, 2021.

Kevala provides the following recommendations to facilitate the transparency and replicability of the analysis and to better characterize the forecast uncertainty of load and DER growth. These recommendations intend for more information to be included in the reporting (this additional data should already be part of the existing analysis inputs and outputs).

When reporting in the GNA tables, the IOUs provide a similar dataset for each of the feeders and banks. There are a few differences, however; this recommendation includes existing and new variables to include in future reporting tables as columns per grid asset.

Recommendation B.2: Include additional reporting data points, such as known loads and econometric load growth, in the GNA table. GNA tables should include the following for each feeder and bank the 1-in-10 adjusted demand by year:

- Adjusted known loads (currently in a separate file): Should be the adjusted value used for new load on the feeder or bank (contribution to net-peak load)
- Econometric load growth
- Base demand for first year of forecast (from SCADA prior to adjusted load due to IEPR inputs for growth and DERs)
- Time stamp of measured peak load

Recommendation B.3: Report on net-load forecast error metrics in the GNA. Add a five-year historical comparison in the GNA comparing the previous GNA year's net-load forecast to the current year weather normalized peak load. Understanding historical load and DER growth and performance can provide insights into the potential of DERs to reduce peak load and risk as a viable option. It also enables the IOUs to identify for which types of feeders or banks the current forecast and disaggregation methods might be performing best and to identify the feeders or banks where improved methods might be needed.

Recommendation B.4: Report on PV and BESS adoption forecast error metrics in the GNA by comparing previous years' interconnection records with the disaggregated PV and BESS values by feeder or bank in the GNA. Understanding DER growth and performance can provide insights into the potential of DERs to reduce peak load and risk as a viable option.

Recommendation B.5: Provide planned load transfers by feeder and bank with date and load amount. IOUs may have included load transfers in the forecast. Year-over-year demand in the GNA, in some cases, has unexpected increases or decreases, potentially attributed to planned load transfers.

Recommendation B.6: Report on the load growth rate metric in the GNA to assess low load growth versus high load growth for feeders and banks by comparing the historical change in load year-after-year. The overall net-load growth rate should be broken down into historical increases in demand and decreases due to DERs, in cases where information about DER deployment is available (for example using recent DER interconnection data to estimate impact on net-load).

Recommendation B.7: Report whether feeders or banks are in a disadvantaged community and report on the percentage of customers with an electricity burden greater than 5%; if utilities do not have such data, Kevala recommends identifying feeders or banks serving a significant number of customers on a CARE rate.

DER Integration and Value Streams

This section includes recommendations related to capturing costs and value streams for determining the cost-effectiveness of DERs beyond the distribution deferral value only considered in the current LNBA calculation.

Project Costs

In its GNA report, PG&E stated: “Both the General Rate Case (GRC) costs and the costs listed in the DDOR report are reflective of the distribution component of project costs. Related transmission upgrade costs are not included in the GRC or the DDOR.” In cases where transmission costs are not being considered and where applicable, Kevala encourages the IOUs to include transmission costs in the DDOR because transmission high-voltage substation bus work can represent a significant cost and could greatly impact the deferral value of substations banks in the LNBA calculation.

Recommendation C.1: Include high-voltage sub-transmission and transmissions costs caused by a grid needwhen estimating planned investments' project costs for the DDOR. If high-voltage bus work is required by the DDOR planned investment project, it should be included in the estimate of project costs because it could greatly impact the locational net benefits analysis (LNBA) deferral value.

DDOR Timing Screen

As discussed in the DIDF Filing Findings and Observations section, the vast majority of the IOUs' grid needs and planned investments are identified in the first three years of the planning horizon, which are then screened out for deferral by the three-year timing screen. Not only is this a function of the IOUs' reliance on their known loads lists to identify grid needs, but some of the grid deficiency categories are only assessed during the first three years; this means the entire category is almost certainly to be excluded.

PG&E and SDG&E only analyze line segment needs for the first three years of the planning horizon, and PG&E also only analyzes voltage support needs for the first three years. SCE does not have software capabilities to assess needs at the line segment level at all. That is, no line segment level needs are eligible for deferral due to the timing screen.[26] Kevala discussed this issue in the section on identifying grid deficiencies, but it bears repeating.

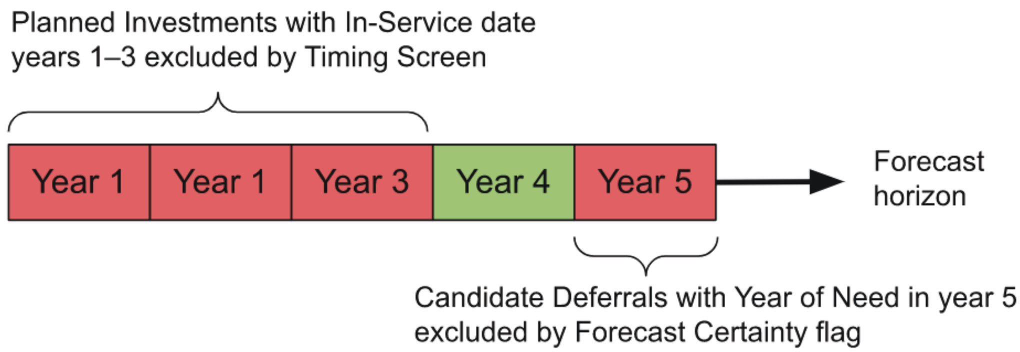
In addition to the three-year timing screen, two of the utilities also flag year 5 planned investments through the forecast certainty flag to exclude them from deferral by moving them to the Tier 3 group (see Figure 11). The result is a narrow window of eligible deferrals. One comment from GPI suggests even removing the timing screen:

> *Since it appears to be a major barrier against increased program participation and success, this question warrants re-consideration. The existence of a DIDF timing screen is an IOU assumption regarding the lead-time for a wide range of DER solutions and procurement pathways (e.g. RFO, SOC, Partnership pilot) capable of meeting distribution planned investments and the associated grid needs. Is a timing screen necessary, or can DER solution development lead times prove self-selecting? Can existing DERS be used, individually or aggregated, to meet deferral needs in a way that moots a timing screen for at least some projects? Can the onus to provide a solution on-time fall to the DER developer who is submitting the bid that offers a DER solution that meets the required*

[26] There could be some exceptions if the year of the associated planned investment falls later than the grid need's year of need.

planned investment online date and need criteria? Put another way, why must lead-time feasibility of DER solutions be baked into the CDO list, where it becomes the responsibility of the IOU to determine what is feasible and what are the lead times for representative DER solutions?

Figure 11: Exclusionary logic of current DDOR prioritization approach. PG&E and SDG&E use a forecast certainty flag starting in year 5; SCE does not use a threshold for the forecast certainty flag. *(Source: Kevala)*



Through a literature review of deferral frameworks employed in other states, Kevala found the following deferral frameworks that have a timing screen less than three years to consider DERs as alternative solutions to planned investments:

- Non-Wires Alternative Framework[27] used by Eversource uses **two years** as the exclusion timing criteria.
- The Joint Utilities[28] in New York consider grid needs in the **18- to 36-month timeline** for feeder-level and below projects.[29]

Kevala encourages the IOUs to review the timing screen and consider candidate deferral opportunities for feeders and banks requiring needs in the 18- to 36-month window and use additional metrics related to the forecast uncertainty and growth rates proposed in recommendations B.3-B.6 to inform the prioritization of CDOs. As suggested by GPI, this could

[27] Eversource, *Non-Wires Alternative Framework*, March 2021, https://www.puc.nh.gov/Regulatory/Docketbk/2020/20-161/LETTERS-MEMOS-TARIFFS/20-161_2021-03-31_EVERSOURCE_LCIRP_SUPPLEMENT.PDF

[28] The Joint Utilities in New York are Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation

[29] Utility-Specific Implementation Matrices for Non-Wires Alternatives Suitability Criteria, https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={3E7E6426-F3FC-46F3-A8C4-CD44625DA792}

include a “DIDF fast track” for grid needs triggered by known or high-certainty load drivers. Kevala also recommends the IOUs identify quick-acting DERs with existing deployment to address near-term needs, especially for line segments such as load management, as commented by the PAO:

- Disaggregate grid needs to a more granular, secondary circuit level, which may facilitate grid needs being satisfied by the aggregation of smaller DERs at the line segment or service transformer levels. At this level, quick response DERs such as demand response or behavior programs can meet these needs.
- Use of immediately dispatchable, currently installed DERs can also circumvent the timing screen, especially if there is granular information on existing DERs and propensity-to-participate data for the adopted premises.

Recommendation C.2: IOUs to identify CDOs that could be procured in year 3 or before for discussion during the DPAG review process. Now that DDOR Request for Offer and Standard Offer Contract procurement processes launch in September of the DIDF cycle, utilities should identify planned investments in year 3 or earlier that are possible candidates for deferral based on new criteria such as small capacity projects or low growth rate areas. IOUs will discuss these projects in the DPAG, and DER developers and aggregators can provide feedback and comments on the feasibility of procuring solutions in year 3 or before.

Conclusions and Next Steps

In this report, Kevala provided a series of recommendations related to the overall DIDF process and the current grid needs forecasting and identification methods; these recommendations are organized into two main categories based on their implementation timeline.

The **DIDF reform recommendations** aim to provide greater transparency and consistency across the PG&E, SCE, and SDG&E GNA and DDOR filings. Specifically, these recommendations focus on metrics and definition improvements designed to enable the utilities, the CPUC, and DDOR stakeholders to better understand the elements of uncertainty associated with using a deterministic load and DER forecast in the GNA. The analysis in this report shows that the contribution of DERs such as EE, PV, and BESS are effective at mitigating thermal capacity constraints. However, such DERs materializing at the feeder and bank locations predicted by the disaggregation methods used by the IOUs is uncertain. This issue greatly affects the CDO selection because the load and DER forecast could be masking a grid need that is not spotted by the GNA process until it is too late to be deferred by DERs.

Tentative **staff proposal recommendations** are identified in Appendix 2. They are intended to inform stakeholder engagement during Track 1 staff proposal development processes. CPUC Energy Division expects to invite stakeholders to propose topics for staff proposal consideration. The preliminary list in Appendix 2 is intended to facilitate stakeholder ideas and comments for this future activity. One or more staff proposals are expected to address the scoping questions for High DER proceeding Track 1, Phase 1, and additional staff proposals are expected to address the scoping questions for Track 1, Phase 2.[30]

In comments received after Kevala's September 27, 2022 informational webinar on this review effort, numerous stakeholders identified the need to address the impact of granular load and DER disaggregation methods in determining grid needs and in identifying opportunities to apply load management and other technologies to alter the shape of demand. These topics are being explored in Parts 1 and 3 of the Electrification Impacts Study, as well as in other discrete parts of the High DER proceeding. Part 1 of the Electrification Impacts Study is intended to validate whether a premise-level forecast, aggregated to various levels of utility distribution system infrastructure, can identify with greater transparency and accuracy specific grid needs over a long enough forecast period to implement the most efficient and necessary investments necessary to support electrification. The Part 1 Study could inform the ability to identify CDO in years 4 and 5

[30] See CPUC November 15, 2021, Scoping Ruling at https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=422949772

and beyond of the DIDF process, which are key areas Kevala found for improvement and that were also recommended in DPAG stakeholders' comments.

Part 3 of the Electrification Impacts Study will examine how to leverage DERs, load management, and other grid technologies to mitigate some of the potentially large grid infrastructure needs of the future, so grid infrastructure and costs are not a bottleneck to California's aggressive decarbonization goals over the next 20 years.[31]

[31] Part 2 of the Electrification Impacts Study includes a staff proposal planned for Track 1, Phase 1 of the High DER proceeding.

Appendix 1: Stakeholder Comments

Table 4: Stakeholder comments and Kevala responses

#	Submitted by	Summary of Comment or Question	Response
1	PG&E	PG&E respectfully requests for an opportunity for stakeholders to comment within 10 business days of the publication of Kevala's report.	This report is expected to be commented on and considered by stakeholders as part of the annual DIDF reform process.
2	PG&E	PG&E believes that many of the proposed Evaluation Focus Areas are not areas which can reasonably be implemented via the existing DIDF Reform process within a single DIDF cycle.	Thank you for this comment. This is important to consider in the annual reform process.
3	PG&E	PG&E requests that stakeholders be allowed an opportunity to thoroughly vet and comment on the basis and assumptions of those recommendations.	This report is expected to be commented on and considered by stakeholders as part of the annual DIDF reform process.
4	PG&E	Any recommendations that impact PG&E's DPP should be based on consideration and analysis of PG&E's entire DPP, not just the DIDF.	Recommendations in this report are based on Kevala's review of IOU GNA and DDOR filings, as specified in the body of the report. Kevala welcomes input and comments into other DPP considerations relevant to the recommendations of this report.
5	PG&E	Will Kevala be presenting any independent distribution planning study results to support their recommended changes to methodologies used by each IOU to generate the GNA and DDOR?	Kevala is not presenting results of an independent distribution planning study in this specific study.
6	PG&E	Will Kevala's results be comparable to the IOUs results (i.e., in a format similar to the appendices that IOUs submit for each individual GNA and DDOR)?	Kevala is not presenting results of an independent distribution planning study in this specific study.
7	PG&E	Will Kevala be providing the inputs and assumptions used to generate the results used as the basis of its recommendations?	Kevala will document and include all inputs and assumptions to any analysis completed in this report.

#	Submitted by	Summary of Comment or Question	Response
8	PG&E	Will Kevala be presenting any assessment of the impact of recommended changes to the IOUs Distribution Planning Process?	Kevala will work with the CPUC Energy Division to ensure the results of the analysis discussed in this report are presented appropriately in the context of the High DER proceeding.
9	PG&E	What is the validation and verification process for input data and results used as the basis for its recommendations?	Kevala also met with the IPE regularly to ask questions and get clarifications on specific methods and data provided by the IOUs. This report is not an audit similar to the IPE work. This report is an augmentation and not a replacement or a repeat of the IPE work. As such, Kevala reviewed all of the public and confidential data provided by the IOUs as part of the 2022 and other historical DIDF fillings, and highlighted specific areas for improvement and recommendations based solely on the content contained in those IOU filings.
10	PG&E	Will Kevala be representing PG&E's Distribution Planning Process (DPP) in its Report?	The scope of this report is focused on the DIDF reform recommendations provided, but issues that may be appropriate for a staff proposal process are also provided (Appendix 2) and may be considered with respect to potential DPP improvements.
11	PG&E	Will there be both public and confidential copies of the report?	There is only a public copy. No identifiable data that meets the 15/15 rule or other sensitive data was presented.
12	SDG&E	SDG&E believes it would be important to ensure stakeholders have an opportunity to comment upon the publication of the "Kevala DIDF Evaluation and Recommendation Report".	The report is expected to be commented on and considered by stakeholders as part of the annual DIDF reform process.

#	Submitted by	Summary of Comment or Question	Response
13	SDG&E	In addition, a post publication workshop should be facilitated by Kevala to elaborate on the methods and analysis basis for its report and answer any questions stakeholders may have. SDG&E respectively request post-publication workshop to be held and a commentary period to be provided after the issuance of the report.	Thank you for the comment. CPUC Energy Division staff expect that the DIDF reform recommendations in this report will be considered in the annual reform process along with the other reports and data provided as part of the DPAG process. The topics identified in Appendix 2 for potential staff proposal consideration will be considered in workshops and other staff proposal development activities to be scheduled by the CPUC.
14	PAO	How could more granular data on Distributed Energy Resources (DERs), especially Electric Vehicles and their potential locations, change the DER growth forecasts and, therefore, the Grid Needs Assessment (GNA)?	The difference(s) between current, allocation-based DER forecasts to a more granular, premise-based DER growth forecast and its impact on the GNA is out of the scope of this particular report. However, it will be explored in the Electrification Impacts Study Part 1, which is planned to be released later in 2022.
15	PAO	How could load management techniques affect load growth and, therefore, the GNA?	The impact of load management techniques and technologies' impact on load growth and the GNA is an important question; however, this question is not addressed in this particular study but may be addressed in other phases of the High DER proceeding. Electrification Impacts Study Part 3 is expected to consider mitigation approaches such as load management.
16	PAO	How could data from DER providers reduce the number of Candidate Deferral Opportunities that are filtered out by the timing screen? Specifically, how could data from DER providers inform improvements to the timing screen assumptions for adequate time needed to design, develop, market, and deploy a DER project?	Kevala agrees that additional data from DER providers could help inform enhanced metrics and deferral opportunity methods, and has included a recommendation consistent with this comment by the PAO in the report.

#	Submitted by	Summary of Comment or Question	Response
17	PAO	How could the GNA disaggregate the identified primary circuit grid needs at a more granular level, specifically at the secondary circuit level (110V/240V)? How could such disaggregation at the secondary circuit level facilitate grid needs being satisfied through an aggregation of many smaller individual (i.e., not organized by an aggregator) DERs or a smaller aggregation of DERs provided through a demand response (DR) aggregator's proposed response to a solicitation? This solution could potentially decrease the marketing time needed to accommodate a larger DR solicitation, and/or make immediate dispatch available.	Kevala considers a few areas of recommendations for the line segment level. However, the secondary system was not an area of focus for this particular report. As described in the *Electrification Impacts Study Research Plan*,[32] in Part 1, Kevala is performing a premise-level disaggregation of various high electrification scenarios and will include the evaluation of secondary system impacts.
18	PAO	Is it possible for grid needs to be satisfied through immediately dispatchable, currently installed DERs, thus circumventing the need for a timing screen in some cases? Can a process be developed that signals connected DER providers to dispatch excess or stored capacity during peak periods?	In this report, this question is recommended to potentially be explored further in future staff proposals, as it relates to the ability of the IOUs to consider grid modernization technologies and the dynamic persistent behavior of DERs in distribution planning.
19	GPI	GPI notes, as an important consideration from the outset of this evaluation process, that DIDF, after four years, has only two small projects operational in all three IOU programs at this time (two small SCE projects, see SCE May 2022 program status report).	Kevala thanks GPI for its suggestion. This outcome is included in this report's analysis.
20	GPI	Can the treatment of known loads be unified across the IOUs? What is the best method? (See also GPI comments on DIDF reforms filed January 20, 2021).	Kevala is including this recommendation to improve the transparency and consistency of known loads in this report.

[32] Kevala, Inc., *Electrification Impacts Study Research Plan*, prepared for the CPUC, March 29, 2022, https://uploads-ssl.webflow.com/62a236e9692c48e1d16898b3/62d8509da2f405169ee10dd0_2022-0329_Electrification%20Impacts%20Study_Final%20Research%20Plan.pdf

#	Submitted by	Summary of Comment or Question	Response
21	GPI	Can the forecast certainty of specific load drivers be integrated into CDO selection? Can grid needs triggered by a known or high certainty load driver justify a DIDF fast track?	Kevala agrees there is a need to consider forecast certainty and understand load drivers. In this report, Kevala recommends that a staff proposal could address inclusion of the forecast uncertainty assessment in all grid needs. This would enable the selection of CDO based on more granular factors such as load and DER growth rate and forecast error metrics. These granular factors could be new proposed metrics for the IOUs to report on for all grid needs.
22	GPI	What biases might the top-down IEPR load forecast disaggregation process impart on the resulting grid needs list? For example, are the steps/rules that define the granular load disaggregation actually aligning with known load requests and DER adoption patterns? Is the load disaggregation process biasing grid needs towards non-DACs? How do the IOUs' load and DER forecast disaggregation methods align with the Kevala bottom-up granular DER adoption assessment scoped in the HDER proceeding; in terms of both output alignment (e.g. granular load and DER predictions) and the predictors of granular DER adoption? What are the similarities and differences between the results of the top- down IEPR load forecast disaggregations and the bottom-up known load forecasts?	In this report, Kevala highlights some of the issues of the top-down IEPR load forecast and reconciliation with the known loads. A more in-depth assessment of the alignment of the Kevala bottom-up DER adoption modeling with the IOUs' load and DER disaggregation methods will be included in the Electrification Impacts Study Part 1 and Part 3.
23	GPI	Can specific load drivers (known load and IEPR forecasted) be used to inform forecast certainty in the CDO ranking? For example, do new water pumping loads have a higher forecast certainty than disaggregated light duty EV load forecasts? Could grid needs triggered by certain forecasted load drivers be awarded a higher forecast certainty ranking in the CDO list?	Kevala agrees there is a need to consider forecast certainty and understand load drivers. Kevala recommends that a future staff proposal might consider including the forecast uncertainty assessment for all grid needs, which would enable the selection of CDO based on more granular factors such as load and DER growth rate and forecast error metrics. These granular factors are new proposed metrics for the IOUs to report on for all grid needs.

#	Submitted by	Summary of Comment or Question	Response
24	GPI	What type of sensitivity analysis is being performed with respect to load forecast certainty, and which load drivers are being considered in the sensitivity analysis?	Kevala agrees there is a need to consider forecast certainty and understand load drivers. In this report, Kevala recommends that a future staff proposal might consider including the forecast uncertainty assessment for all grid needs, which would enable the selection of CDO based on more granular factors such as load and DER growth rate and forecast error metrics. These granular factors are new proposed metrics for the IOUs to report on for all grid needs. Including such metrics in the GNA would enable the sensitivity analysis recommended by GPI.
25	GPI	How is the projected rollout of complementary technologies, and their impact on hourly and seasonal load profiles, being considered? For example, how does load shifting via higher levels of demand response, smart charging (including grid-to-vehicle and vehicle-to-grid), and various energy storage options affect 8760 load profile forecasts? Similarly, how is the rollout of energy efficiency technologies projected and accounted for in the load forecast?	In this report, this topic is recommended for potential consideration in future staff proposals, as it relates to the ability of the IOUs to consider grid modernization technologies and the dynamic persistent behavior of DERs in distribution planning.
26	GPI	What future impacts of climate change and their effects on load are being considered? For example, are the impacts of changing precipitation patterns on the water supply, and the corresponding increases in electricity required to supply water demand, such as through additional water transportation and desalination, being accounted for?	Climate change impacts on temperature are suggested for consideration in the staff proposal, while impacts on water supply are a good suggestion but are not addressed in this study.
27	GPI	GPI supports the scoped Kevala-led evaluation of the DIDF timing screen – this timing screen remains a major barrier to increasing the modest size of the CDO list. We suspect that a greater volume of CDOs as well as diversity of project location and need are important for enabling additional CDOs.	Kevala has provided recommendations in this report related to the DIDF timing screen.

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#	Submitted by	Summary of Comment or Question	Response
28	GPI	GPI queries whether a timing screen is necessary. Since it appears to be a major barrier against increased program participation and success, this question warrants re-consideration. The existence of a DIDF timing screen is an IOU assumption regarding the lead-time for a wide range of DER solutions and procurement pathways (e.g. RFO, SOC, Partnership pilot) capable of meeting distribution planned investments and the associated grid needs. Is a timing screen necessary, or can DER solution development lead times prove self-selecting? Can existing DERS be used, individually or aggregated, to meet deferral needs in a way that moots a timing screen for at least some projects? Can the onus to provide a solution on-time fall to the DER developer who is submitting the bid that offers a DER solution that meets the required planned investment online date and need criteria? Put another way, why must lead-time feasibility of DER solutions be baked into the CDO list, where it becomes the responsibility of the IOU to determine what is feasible and what are the lead times for representative DER solutions? If the timing screen was removed, how could this improve or hinder the adoption of DER solutions and progress towards state goals? If the timing screen was removed, would DER solution development lead times be sufficient in the process of meeting grid needs and executing planned investments?	Kevala has provided recommendations in this report related to the DIDF timing screen.

#	Submitted by	Summary of Comment or Question	Response
29	GPI	Are IOUs adequately incentivized to eliminate the majority of planned investments from the CDO list? That is, how does each IOU proceed with meeting the remainder of the planned investments that do not pass the timing screen? Do the IOUs wait until the year of need to confirm a grid need is triggered, or implement a temporary solution last minute prior to investing in a traditional wires solution? Are traditional wires solutions only implemented after a grid need is confirmed (e.g. 100% need certainty)? Asking questions regarding the investment process for non-CDOs may elucidate how planned investments from the DIDF are integrated into the bulk Distribution Planning Process (DPP) and may inform if IOUs are incentivized to eliminate over 90 percent of planned investments from the CDO process.	Kevala thanks GPI for these questions that will be documented as areas of consideration that may be explored further in a staff proposal.
30	GPI	How could IOUs be incentivized to increase the number and megawatts of identified CDOs? How would each type of stakeholder incur positive or negative impacts from refining processes to increase the number and size of the CDO list?	Kevala thanks GPI for these questions that will be documented as areas of consideration that may be explored further in a staff proposal.
31	GPI	Resiliency as an eligible technical screen: How is each utility determining and defining resiliency GNAs and resultant planned investments/CDOs? Should resiliency be redefined to expand CDO opportunities beyond microgrids, and/or to better define the treatment of microgrid within the DIDF? How does the DIDF currently interface with the Microgrid proceeding and does it support microgrid development in addition to or in concert with the microgrid proceeding?	Kevala agrees with GPI, and the definition of resiliency is included in a recommendation in this report.
32	GPI	Could redefining resiliency in the DIDF support a wider range of DER solutions (i.e. beyond microgrids) and/or grid needs?	Kevala agrees with GPI, and the definition of resiliency is included in a recommendation in this report.

#	Submitted by	Summary of Comment or Question	Response
33	GPI	What would be the most beneficial way to redefine resiliency to accelerate progress towards state goals? Would it make sense to include local energy storage and energy efficiency measures alongside community-scale renewables for a more complete consideration of resiliency tools?	Kevala agrees with GPI, and the definition of resiliency is included in a recommendation in this report.
34	GPI	GPI has raised concerns regarding the use of a quartile-based ranking system for Tier 1, 2, and 3 CDOs. The relative ranking system is based on the annual CDO population spread, versus objective, static ranking thresholds.	Kevala agrees with GPI's concern. The ranking of CDOs is an area of consideration that may be explored further in the High DER proceeding.
35	GPI	In general, we also encourage Kevala and others in the HDER proceeding chapter of DIDF reform to review previous stakeholder/intervenor filings in the DRP proceeding, on the topics that remain scoped in this proceeding, as many of the topics in scope for DIDF reform in 2022 were identified and iteratively discussed in the DRP proceeding – but often without resolution (hence those issues being carried over into this new proceeding).	Kevala thanks GPI for this recommendation.
36	GPI	GPI encourages the Commission, Kevala and other parties (e.g. IPE, intervenors, CPUC staff) to explore whether the IOUs have met the DIDF reform requirements established in the May 11, 2020 DRP ruling. If IOUs have not met these DIDF reform requirements, what support or direction do IOUs need to meet these requirements?	Thank you for this comment. DIDF regulatory compliance by the IOUs is a topic that may be further explored in the High DER proceeding.

#	Submitted by	Summary of Comment or Question	Response
37	GPI	Is a quartile CDO ranking system necessary? Can developers and their proposed DER solutions/bids prove self-selecting in terms of which planned investments are feasible for DER solutions? For example, DER developers with detailed, insider knowledge of their DER capabilities, costs, and timelines, could themselves determine if a CDO is a good/poor fit and whether it warrants submitting a bid. How have selected (e.g. Tier 1) and successful projects ranked in the total CDO stack from all years the DIDF has been implemented? Which projects would have been eliminated or added to Tier 1, 2, or 3 rankings based on all time, versus annual, CDO population attributes?	Kevala agrees with GPI's suggestion. This suggestion could be considered in the staff proposal process to solicit information from DER providers in coordination with the work performed by the Independent Evaluator (IE).
38	GPI	On Slide 34 of PG&E's 2022 DPAG presentation, PG&E proposes to Flag CDOs with a year of need > 4 years. If they implement this flag in future DIDF cycles, only planned investments with a year of need 4 years from the DIDF cycle year will qualify as a CDO eligible for DER solution solicitation. How would this flag impact CDO tiers and eligibility in past DIDF cycles? Is this extremely narrow window of forecast certainty eligibility warranted? What is the persistence of grid needs from one year to the next in each of the forward planning years? For example, based on past DIDF cycle GNA data, what is the probability that grid needs forecasted 3 years (4, 5, 6 years?) out were still present 1 year from the date of need	The interactions between the forecast certainty flag, known loads list, and timing screen are discussed in this report. Recommendations for modifying the forecast certainty method are identified for potential consideration in a staff proposal.
39	GPI	How might limiting CDO eligibility to a year of need >4 years affect CA's ability to leverage federal funding opportunities, such as the Inflation Reduction Act (IRA), to reduce the cost of and accelerate progress towards high penetrations of DERs?	Kevala thanks GPI for this comment, which may be appropriate for further consideration in a staff proposal.

#	Submitted by	Summary of Comment or Question	Response
40	GPI	Are there predictor variables other than year of need that can inform grid need forecast certainty (e.g. load driver)? Towards other predictors of forecast certainty, PG&E provides a forecast certainty questionnaire used to score the forecast certainty for CDOs (PG&E DPAG Presentation, slide 35). The first question is: "Is the area served by the project within two miles of: [n] highways?" GPI queried whether and how highway proximity was an appropriate predictor of other load drivers. PG&E explained that it pertains to DC Fast Chargers. Questions by Richard Khole of PAO revealed that the majority of new load applications are not for DC fast Charging stations. While DC Fast charging stations interconnection requests may increase in future year, the drivers for total new load will continue to include a wide range of sources (e.g. central valley pumping, new housing developments etc.). GPI suspects that highway proximity is not an appropriate predictor of load (and resultant grid need) forecast certainty for all load types. GPI encourages an assessment of whether forecast certainty predictor criteria specific to load driver/type could facilitate CDO selection by improving forecast certainty for CDOs in years 4+ and/or by improving certainty for projects in year 3 that could be eligible for inclusion in the CDO list of in a DIDF fast track.	Kevala agrees with GPI on the need to better understand the driver of grid needs. Potential recommendations for modifying the forecast certainty method are identified in this report, including consideration of the uncertainty of new EV loads.
41	GPI	GPI encourages Kevala to review the IOUs' CDO selection criteria for Partnership Pilot participation. We query whether Kevala's bottom-up granular DER adoption assessment, or DER developer input, can inform whether these criteria are suitable for informing Partnership Pilot CDO selection.	Thank you for this recommendation. This question may be appropriate for consideration in a staff proposal after Electrification Impacts Study Part 1 is completed.
42	GPI	Is it necessary to divide CDOs into three procurement pathways or could DER developers elect which CDO and solicitation pathway would best enable their DER solution? What would the pros and cons be of removing the procurement tracks?	Kevala thanks GPI for this suggestion. This suggestion could be considered in the staff proposal process to solicit information from DER providers in coordination with the work performed by the IE.

#	Submitted by	Summary of Comment or Question	Response
43	GPI	GPI encourages an assessment on how IOUs might enable co-hosted DIDF and ICA data while improving the user interface and experience more generally. Offering the option to combine in a single view the ICA maps (i.e. the present-day distribution grid availability for new load and generation interconnection) and DIDF maps (i.e. the forecasted distribution grid needs eligible for DER deferral and co-located LNBA) will facilitate both stakeholder and DER developer review of CDOs and potential barriers to DIDF success.	Kevala thanks GPI for this comment and recommends that GPI also submit this idea as part of the Data Portal Improvement activities of this proceeding.
44	GPI	GPI urges engagement with DER developers to better understand the barriers to DIDF participation.	Kevala thanks GPI for this suggestion. This suggestion could be considered in the staff proposal process to solicit information from DER providers in coordination with the work performed by the IE.
45	GPI	DER Developers should be asked to weigh in on whether the technical and timing CDO screens are removing optimal projects for DER deferrals. Are the Partnership Pilot and SOC Pilot CDO selection screens suitable for selecting the optimal CDOs for these procurement pathways?	Kevala thanks GPI for this suggestion. This suggestion could be considered in the staff proposal process to solicit information from DER providers in coordination with the work performed by the IE.
46	GPI	Are DER solution lead times shorter or longer than what is supported by the RFO, SOC, and Partnership Pilot? Are lead times grid need dependent? What are the factors that currently determine DER solution lead time?	Kevala thanks GPI for this suggestion. This suggestion could be considered in the staff proposal process to solicit information from DER providers in coordination with the work performed by the IE.
47	GPI	What are the largest barriers to developing DER solutions that can participate in the DIDF? What additional information or conditions (e.g. more projects to bid on) would to help DER developers engage in DIDF bidding?	Kevala thanks GPI for this suggestion. This suggestion could be considered in the staff proposal process to solicit information from DER providers in coordination with the work performed by the IE.

Appendix 2: Potential High DER Proceeding Staff Report Topics for Future Consideration

This section identifies broader or longer-term recommendations (summarized in Table 5) that Kevala suggests be considered in a staff proposal, either during Phase 1 or Phase 2 of the High DER proceeding Track 1. The Electrification Impacts Study's Part 1 report will also provide insights into long-term grid needs and grid upgrade costs due to the impact of electrification that will support some of the recommendations provided in this report.

Table 5: Tentative staff proposal process topics *(Source: Kevala)*

#	Topic Area	Tentative Kevala Recommendations for Staff Proposal Consideration
1	The potential of DERs to defer capital investments at the transmission level could offer significant value, but it is not currently considered.	**Coordinate with the IOUs and the California Independent System Operator's (CAISO's) transmission planning process (TPP) on the value of distribution-level DERs for deferring transmission constraints:** ● IOUs to provide illustrative deferral value calculations for non-CPUC jurisdictional transmission projects already identified in the latest adopted CAISO TPP. ● Coordinate with the CAISO Distributed Energy Resource Provider[33] and Distributed Energy Resource Aggregation.[34] ● Invite CAISO representatives to a DPAG workshop and present findings.
2	The current five-year planning horizon does not adequately anticipate the DER deployment and economy-wide electrification associated with the 2035 zero-emission transportation and 2045 100% clean electric power goals.	**Increase planning horizon length** from five years to 15 years to align with the CEC planning horizon; this adjustment will align distribution infrastructure and DER planning with the 2035 zero-emission transportation and 2045 100% clean electric power goals. The upcoming Electrification Impacts Study Part 1 report uses a forecast horizon through 2035 for consistency with the IEPR forecast.
3	Forecast uncertainty is solely considered through the forecast certainty metric in the DDOR prioritization process as a post-processing, exclusionary screen.	**Move forecast uncertainty analysis into the GNA itself**. By improving the forecasting method, the year-of-need flag could be removed to expand viable candidate deferrals in year 5 and beyond.
4	The current deterministic forecast method does not consider that load growth or DER deployment could be higher or lower than a single estimate, creating the risk of over-deploying DERs in some areas and lost DER deferral opportunities in others.	**Consider multiple scenarios to characterize risk** in the GNA process. A range of load and DER disaggregation values can inform forecast uncertainty metrics using probabilistic approaches. The upcoming Electrification Impacts Study Part 1 report, for example, considers five scenarios with different customer tariffs and rates of transportation electrification adoption.

[33] Proceeding R.21-06-017, opened with an *Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future*, issued on July 2, 2021, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M390/K664/390664433.PDF.
[34] CAISO, "Distributed energy resource provider," http://www.caiso.com/participate/Pages/DistributedEnergyResourceProvider/Default.aspx.

#	Topic Area	Tentative Kevala Recommendations for Staff Proposal Consideration
5	The forecast approach does not proactively identify high load growth areas that do not currently have a grid need but are at a high risk of developing a grid need if load growth exceeds or DER deployment falls below the current deterministic forecast.	**Develop forecast uncertainty metric(s)** to identify feeders and banks that are nearing capacity, as well as those with low load growth, to leverage existing DERs and new DERs to proactively mitigate and defer grid needs. To respond to any anticipated needs, consider analysis for DER procurement and leveraging existing DER capabilities to respond to any negative grid impacts.
6	It is unclear through the current voltage analysis methods described by the IOUs if voltage deficiencies are being identified in the long term. The methods, as described, have limited ability to anticipate issues at the line segment level or overvoltage conditions due to DERs that do not occur at the peak hour. There is a range of voltage analysis capabilities across the IOUs, which results in inconsistent identification of grid needs across the service territories.	**Update voltage deficiency methods:** ● Transition to identifying voltage deficiencies through a power flow-based analysis conducted down to the line segment and over the same forecast horizon as the rest of the DIDF process (currently five years). The IOUs are in different stages of transition from using a single-point forecast approach to a time series or profile-based forecast; this recommendation depends largely on the completion of those efforts. ● Conduct future voltage deficiency analyses using a time series of power flow simulations. Ideally, a power flow analysis would be run down to the line segment level for every time-step in an hourly resolution time series (ideally an 8760 or at minimum a 576) to analyze the frequency and magnitude of voltage violations. Due to the high computational requirements of such an analysis, consider immediately adding landmark operating time points during the year, such as midday on a clear sky, low load day, to assess the impacts of exporting PV. ● Indicate in the GNA whether a voltage need is driven primarily by under-voltage violations, over-voltage violations, or a combination. Any voltage issues that can be resolved by upgrading capacity banks or feeders need DDOR attention and need to be reported.
7	As California experiences more extreme heat waves like those in 2020 and 2022, reconsider using 30-year historical temperature adjustments.	**Address climate change in the demand forecast with weather adjustments.** For example, the CEC is considering using 15-year historical (versus 30-year) or using a climate models forecast, such as Cal-Adapt RCP 8.5,[35] especially for long-range forecasts.

[35] Representative Concentration Pathways (RCP) forecast long-term climate futures under different greenhouse gas concentrations. RCP 8.5 represents a high emissions pathway. Cal-Adapt provides climate forecast data for California, which is statistically down-scaled from the global RCP models.

#	Topic Area	Tentative Kevala Recommendations for Staff Proposal Consideration
8	It is unclear how the GNA identifies PV and generation grid needs.	**Include an explicit grid deficiency category in the GNA for PV and generation hosting capacity for the same timeframe as the existing GNA.** Grid needs identification should consider addressing interconnection constraints, so that long-term hosting capacity constraints can be proactively addressed and deferred with DERs.
9	The IOUs use a range of methods to identify the four grid needs categories, which is expected to result in wide variance in successfully identifying grid needs and deferral opportunities.	**Implement consistent methods across IOUs.** Unless the IOUs have a specific justification for different methods in the GNA and DDOR, then Kevala recommends all IOU analyses should be similar, as encouraged in Decision 18-02-004 on DIDF improved data sharing and documentation. Some examples of inconsistency include the following: ● Known loads calculations and 1-in-10 calculations vary across the IOUs. ● Voltage studies have discrepancies across the IOUs. ● Resiliency/microgrids identification is inconsistent, which will be affected by a decision on whether to redefine the resiliency grid need category. ● All IOUs use different questionnaires for their forecast uncertainty screens and do not use a scenarios- or risk-based analysis proactively.
10	Capacity constrained grid areas that could stall community electrification goals need to be studied and hosting capacity data shared.	**Select areas for case studies related to capacity-constrained distribution grid areas** to be developed by the IOUs as supplements to their annual GNA/DDOR filings. The studies and associated data should be reviewed in the DPAG and shared with the local community. Case studies may also be prepared by Kevala to support staff proposal recommendations for DIDF and DPP improvements. These case studies should be coordinated with the planned community engagement needs assessment. In addition, hosting capacity data based on GNA forecasts of five years (at minimum) should be made available to all communities, community planners, and developers. This could be accomplished via future updates to the existing data portals.

#	Topic Area	Tentative Kevala Recommendations for Staff Proposal Consideration
11	The GNA does not consider new DER capabilities and grid modernization technologies that can be deployed operationally to impact grid needs, such as capacity and voltage grid needs.	**Propose methods on how to include the increased dispatchability of DERs and expected grid modernization technology capabilities in their ability to reduce peak load and improve voltage management and resiliency constraints in the DIDF.** In coordination with the Track 3 Smart Invert Operationalization Working Group's (SIOWG's) activities for the High DER proceeding and based on known DER capabilities combined with expected future regulations. Note that the SIOWG's report is planned for Q1 2023 followed by a SIOWG staff proposal planned for Q2 2023. Some of the expected use cases include: ● Commanded maximum generation export limits, ● Minimum generation export requirements, ● Maximum load limits (EV charging, storage charging, net import), and contractual agreements. ● Additional capabilities could include voltage support, nanogrid and microgrid formation for grid safety and reliability, and autonomous responses of DER to grid conditions (anti-islanding, voltage response). In addition, consider how IOUs' Advanced Distribution Management System (ADMS)/DER Management System (DERMS) capabilities, more widespread and more granular and timely communications reach, improved monitoring and state estimation of grid conditions (frequency, voltage, active power, reactive power), improved power flow and contingency analysis capabilities, and potentially requirements for aggregator DERMS and DER facility DERMS will increase dispatchability for peak load reduction and voltage management capabilities.

Transmission Value Opportunities

The current DIDF framework captures the value of distribution deferral of a traditional planned investment. While the DIDF framework does not prevent DER developers from seeking multiple value streams, some locational values are still not quantified in the state's avoided cost calculator or resource adequacy and other value streams. An important feature in this category is the ability of DERs to provide transmission congestion relief for already identified transmission constraints in the California Independent System Operator's (CAISO's) transmission planning process (TPP).

Recommendation 1: Coordinate with the IOUs and the CAISO's TPP on the value of distribution-level DERs for deferring transmission constraints:

- IOUs to provide illustrative deferral value calculations for non-CPUC jurisdictional transmission projects already identified in the latest adopted CAISO TPP.
- Coordinate with the CAISO Distributed Energy Resource Provider and Distributed Energy Resource Aggregation.
- Invite CAISO representatives to a DPAG workshop and present findings.

Increase the Length of DIDF Planning Horizon

The IEPR demand forecast is through 2035. Given the data, the IOUs could increase the length of the DIDF planning horizon to 2035 to be consistent with the current IEPR forecast length. To meet the aggressive timelines for transportation electrification in parallel with a 100% clean energy supply, IOUs will need to have a long-term view on balancing grid infrastructure and deploying load-reducing DERs. Developing and implementing long-term localized forecasts for load and DER supports this recommendation. The upcoming Electrification Impacts Study Part 1 report uses a forecast horizon through 2035 for this same purpose and shows that long-term load and DER disaggregation in the distribution system to identify grid needs is possible.

For future years, an increasing level of uncertainty results in a need to add a risk management approach to the forecast. As such, current forecast uncertainty methods in the DIDF will need to be reconsidered (discussed further below).

Recommendation 2: Increase planning horizon length from five years to 15 years to align with the CEC planning horizon; this adjustment will align distribution infrastructure and DER planning with the 2035 zero-emission transportation and 2045 100% clean electric power goals. The upcoming Electrification Impacts Study Part 1 report uses a forecast horizon through 2035 for consistency with the IEPR forecast.

Forecast Uncertainty

As discussed in the Forecast Certainty and Timing section, forecast uncertainty is a major concern with the current deterministic methods reported by the IOUs. Stakeholders such as GPI also addressed concerns that no description of a sensitivity analysis performed with respect to load forecast certainty is provided. There is a need to balance risk. Some grid needs require a wired solution or can be addressed with reliable reduction or shifting of load during periods of identified need. The certainty of the load reduction for investment deferral needs to be addressed to manage risk.

Kevala suggests that forecast uncertainty be moved into the GNA analysis using a scenario-based approach to conduct sensitivities around the future demand and DER adoption forecasts to develop the grid needs list. Another approach is to develop forecast certainty metrics, particularly to conduct sensitivity analysis around the 100% facility rating threshold used to identify capacity grid needs. To fully capture the appropriate solution for a grid need, the forecast certainty metric should be analyzed objectively and applied to all planned investments, not just the DDOR funnel of CDOs that have passed the timing and technical screens (aligns to stakeholder comments recommending that the forecast certainty of specific load drivers be integrated into CDO selection).

Recommendation 3: Move forecast uncertainty analysis into the GNA itself. By improving the forecasting method, the year-of-need flag could be removed to expand viable candidate deferrals in year 5 and beyond.

Recommendation 4: Consider multiple scenarios to characterize risk in the GNA process. A range of load and DER disaggregation values can inform forecast uncertainty metrics using probabilistic approaches. The upcoming Electrification Impacts Study Part 1 report, for example, considers five scenarios with different customer tariffs and rates of transportation electrification adoption.

Recommendation 5: Develop forecast uncertainty metric(s) to identify feeders and banks that are nearing capacity, as well as those with low load growth, to leverage existing DERs and new DERs to proactively mitigate and defer grid needs. To respond to any anticipated needs, consider analysis for DER procurement and leveraging existing DER capabilities to respond to any negative grid impacts.

Voltage Studies

In contrast with the capacity and back-tie grid needs categories, the IOUs have disparate capabilities and approaches to assess voltage needs. PG&E's voltage analysis capabilities are the most complete, including the capability to run power flow down to the line segment level. However, PG&E only conducts this analysis for a single time-point with 1-in-10 loading and for the first three years of the planning horizon, which will be automatically rejected by the three-year timing screen.

As of its most recent 2021 GNA report, SCE did not have the software capability to conduct line segment-level power flow analysis and could not yet comply with the line segment-level analysis required in the DIDF. To determine voltage needs at the circuit/feeder and substation levels, SCE used a single time- analysis, although it anticipated the capacity to use an 8760 loading profile following its planning tool software upgrades.

SDG&E provides limited documentation on its voltage analysis method, though it does note that it only conducts voltage analysis for the first three years, which is also eliminated by the timing screen. From conversations with the IPE, Kevala understands that SDG&E is analyzing power flow models only for selected circuits after customer complaints or field engineering indicates a voltage issue is occurring. If this is still the case, this method that relies on present day customer complaints to identify voltage issues is at odds with the intention of the GNA forecast. It is also not clear how the utility would assign the year of need for a known voltage deficiency, or if it is simply reporting the year in which a known voltage issue is scheduled for resolution by a planned investment.

While under-voltage violations have been the primary concern of distribution planning in the past, the proliferation of exporting DERs such as PV and storage to meet California's state policy goals will increase the likelihood of frequent overvoltage conditions as well; these are not captured in the IOUs' current single time-point analysis of the peak net-load hour. In addition, the DIDF does not consider hosting capacity, which potentially limits the ability to meet these goals.

Recommendation 6: Update voltage deficiency methods:

- Consider overlap with IOUs' interconnection processes in grid needs identification so that long-term hosting capacity constraints can be proactively addressed.
- Transition to identifying voltage deficiencies through a power flow-based analysis conducted down to the line segment and over the same forecast horizon as the rest of the DIDF process (currently five years). The IOUs are in different stages of transition from using a single-point forecast approach to a time series or profile-based forecast; this recommendation depends largely on the completion of those efforts.
- Conduct future voltage deficiency analyses using a time series of power flow simulations. Ideally, a power flow analysis would be run down to the line segment level for every time-step in an hourly resolution time series (ideally an 8760 or at minimum a 576) to analyze the frequency and magnitude of voltage violations. Due to the high computational requirements of such an analysis, consider immediately adding landmark operating time points during the year, such as midday on a clear sky, low load day, to assess the impacts of exporting PV.
- Indicate in the GNA whether a voltage need is driven primarily by under-voltage violations, over-voltage violations, or a combination. Any voltage issues that can be resolved by upgrading capacity banks or feeders need DDOR attention and need to be reported.

Climate Forecast Adjustments

The CEC uses weather statistics including daily minimum and maximum temperatures and heating and cooling degree days for the load forecasting analysis. For the 2021 IEPR, the CEC conducted weather normalizing loads by developing a relationship between peak loads and 30 years of historical data. Then it processed peak weather variant (1-in-x) scenarios.[36] However, the CEC team revisited the forecast adjustments for climate impacts to consider recent warming trends. Their analysis included applying greater weight to more recent historical years or using 15 versus 30 years of historical data or other alternatives.[37] For longer horizons, a climate model such as Cal-Adapt can be used to estimate climate futures under different RCPs, which forecast long-term climate change under different greenhouse gas concentrations.

[36] California Energy Commission, *Final 2021 Integrated Energy Policy Report, Volume IV: California Energy Demand Forecast*, February 2022, https://efiling.energy.ca.gov/GetDocument.aspx?tn=241581&DocumentContentId=75546.
[37] California Energy Commission, "Peak Electricity Demand: California Energy Demand Forecast, 2021-2035," December 2021, https://efiling.energy.ca.gov/GetDocument.aspx?tn=240960.

Recommendation 7: Address climate change in the demand forecast with weather adjustments. For example, the CEC is considering using 15-year historical (versus 30-year) or using a climate models forecast, such as Cal-Adapt RCP 8.5, especially for long-range forecasts.

PV and Generation Hosting Capacity Grid Needs

It is unclear if and how the current GNA categories address PV and generation interconnection constraints. Without understanding those constraints concurrent with grid needs, it is difficult to assess if DERs might be able to defer grid needs. If there is no interconnection capacity, DERs would not be able to be installed. Therefore, Kevala recommends adding a new grid deficiency category to be evaluated for grid needs to proactively address PV and generation interconnection hosting capacity constraints in the future. This would provide more transparency into how interconnection constraints are being proactively identified, opening up further opportunities for DERs to avoid or defer traditional solutions.

Recommendation 8: Include an explicit grid deficiency category in the GNA for PV and generation hosting capacity for the same timeframe as the existing GNA. Grid needs identification should consider addressing interconnection constraints, so that long-term hosting capacity constraints can be proactively addressed and deferred with DERs.

Methods Consistency

Kevala found that the IOUs do follow the same framework for the GNA and DDOR. However, each IOU may accomplish the GNA and DDOR using their own methods. In some cases, IOUs can justify having different methods for the calculation steps. Kevala recommends increasing consistency in areas where it makes sense and that the IOUs offer justification for instances where an IOU-specific approach is an appropriate alternative.

For example, handling known load data in a consistent way is needed to ensure it is properly merged with the IEPR forecast and used in load disaggregation. The consistency allows for a comprehensive review of the distribution grid investments and oversight to ensure the IOUs identify the most cost-effective solution. Due to the lack of clarity and differences across the IOUs, the IPE does not have the same tools or ways to validate the data without a demonstration or walk-through of each IOU's use of proprietary software.

This recommendation is in line with the Administrative Law Judge's prior rulings, which include the following expectations:

- *I recognize the long-term usefulness of consistent datasets for analytic purposes and acknowledge that the IOUs' process for producing the GNA data is complex and requires significant lead time to produce specific outputs. Thus, I expect that the IOUs will work towards a common, comparable dataset by 2020, and that the IOUs identify what changes are necessary to achieve this objective in their 2019 DDOR report.* [38]
- *The IOUs are working towards achieving common, comparable GNA/DDOR filing datasets (i.e., standardizing filing data and documentation across the IOUs), but more work is still needed," and "The IOUs should collaborate such that there is a common understanding of each label and formula used in the 2020 Joint Prioritization Metrics Workbook Template and any embedded guidelines for qualitative data (e.g., the Forecast Certainty table of guidelines described below).* [39]
- *We believe that the IOUs and the DPAG should gain experience with different prioritization approaches before prescribing a given methodology for ongoing use.*[40]

Recommendation 9: Implement consistent methods across IOUs. Unless the IOUs have a specific justification for different methods in the GNA and DDOR, then Kevala recommends all IOU analyses should be similar, as encouraged in Decision 18-02-004 on DIDF improved data sharing and documentation. Some examples of inconsistency include the following:

- Known loads calculations and 1-in-10 calculations vary across the IOUs.
- Voltage studies have discrepancies across the IOUs.
- Resiliency/microgrids identification is inconsistent, which will be affected by a decision on whether to redefine the resiliency grid need category.
- All IOUs use different questionnaires for their forecast uncertainty screens and do not use a scenarios- or risk-based analysis proactively.

Community Electrification Goals in Capacity Constrained Areas

Several communities in California have expressed concern and outright frustration with local grid capacity constraints stalling electrification plans. The GNA does not reflect the current constraints experienced by such communities, only deficiencies in serving load. As such, we recommend that

[38] Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework Process, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M288/K311/288311944.PDF, p. 5.

[39] Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework—Filing and Process Requirements, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M337/K288/337288441.PDF, p. 18 and p. 39.

[40] Decision on Track 3 Policy Issues, Sub-Track 1 (Growth Scenarios) and Sub-Track 3 (Distribution Investment and Deferral Process), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K858/209858586.PDF.

the IOUs, along with community stakeholders, select communities for case studies related to capacity-constrained distribution grid areas to be developed as supplements to the annual GNA/DDOR filings. These studies and associated data should be reviewed in the DPAG and shared with the local community. Case studies may also be prepared by Kevala to support staff proposal recommendations for DIDF and DPP improvements.

We also recommend that ICA hosting capacity and GNA forecast data be shared and reviewed with communities, and understand if there are any discrepancies and improvements to best proactively plan investments and candidate deferral opportunities to enable electrification goals.

Finally, work to improve the ICA hosting capacity and GNA forecasts will be coordinated with other activities in the High DER proceeding such as the upcoming Data Portals Staff Proposal and the planned Community Engagement Needs Assessment. The latter is expected to include working and/or focus groups that would be a natural fit to assist with the case studies.

Recommendation 10: Select areas for case studies related to capacity-constrained distribution grid areas to be developed by the IOUs as supplements to their annual GNA/DDOR filings. The studies and associated data should be reviewed in the DPAG and shared with the local community. Case studies may also be prepared by Kevala to support staff proposal recommendations for DIDF and DPP improvements. These case studies should be coordinated with the planned community engagement needs assessment. In addition, hosting capacity data based on GNA forecasts of five years (at minimum) should be made available to all communities, community planners, and developers. This could be accomplished via future updates to the existing data portals.

Grid Modernization Considerations

Grid modernization and emerging Internet of Energy technologies are enabling active control of the distribution system to manage peak load and increase resiliency. On the one hand, as the IOUs are developing and implementing grid modernization plans, it is unclear how new software and hardware technologies should be accounted for in the DIDF process. For example, if utilities fully deploy ADMS and DERMS, it is unclear how the current capacity, voltage, reliability, and resilience evaluation methods for grid needs can account for these new operational capabilities, which should directly affect peak demand and voltage management strategies and be considered in grid needs identification. On the other hand, DERs are being operationalized with the ability to shape their behavior according to local constraints, predetermined interconnection agreements, or via communication systems.

The DIDF should accommodate in its assumptions the short-term, mid-term, and long-term capabilities of DERs and grid modernization technologies that will affect the evaluation of constraints that determine grid needs and planned investments.

Recommendation 11: Propose methods on how to include the increased dispatchability of DERs and expected grid modernization technology capabilities in their ability to reduce peak load and improve voltage management and resiliency constraints in the DIDF. In coordination with the Track 3 Smart Invert Operationalization Working Group's (SIOWG's) activities for the High DER proceeding and based on known DER capabilities combined with expected future regulations. Note that the SIOWG's report is planned for Q1 2023 followed by a SIOWG staff proposal planned for Q2 2023. Some of the expected use cases include:

- Commanded maximum generation export limits,
- Minimum generation export requirements,
- Maximum load limits (EV charging, storage charging, net import), and contractual agreements.
- Additional capabilities could include voltage support, nanogrid and microgrid formation for grid safety and reliability, and autonomous responses of DER to grid conditions (anti-islanding, voltage response).

IOUs' advanced distribution management system (ADMS)/DER management system (DERMS) capabilities, more widespread and more granular and timely communications reach, improved monitoring and state estimation of grid conditions (frequency, voltage, active power, reactive power), improved power flow and contingency analysis capabilities, and potentially requirements for aggregator DERMS and DER facility DERMS to increase dispatchability for peak load reduction and voltage management capabilities.

(END OF ATTACHMENT 2)