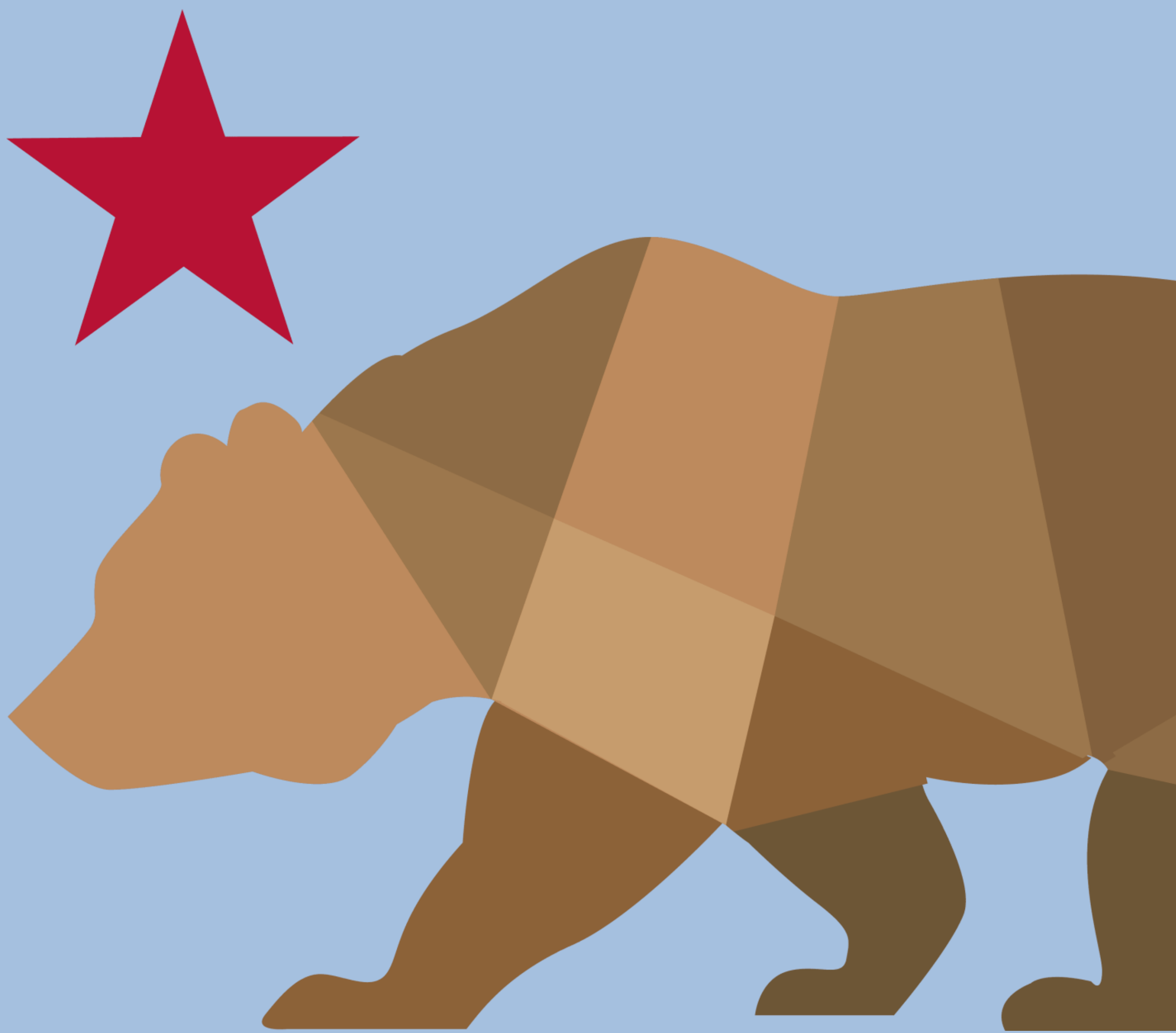
California's Grid Modernization Report 2025



California Public Utilities Commission

CALIFORNIA'S GRID MODERNIZATION REPORT TO THE GOVERNOR AND LEGISLATURE

December 2025

About This Report

The California Public Utilities Commission reports biennially to the Legislature and Governor on progress made toward modernizing the state's distribution and transmission grid and the impacts of distributed energy resources on the state's distribution and transmission grid and ratepayers per Public Utilities Code Section 913.6.

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On the Cover: California Bear courtesy of ca.gov.

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FOREWORD

Road Map to This Report

The Grid Modernization Report serves as a biennial report to the Legislature and the Governor on the progress made toward modernizing the state's distribution and transmission grid and the impacts of distributed energy resources (DER) on the state's distribution and transmission grid and ratepayers. Each edition of the report will include grid modernization updates from the three major investor-owned utilities (IOUs), and a special focus topic. Future editions will highlight different themes and aspects of grid modernization. This first edition will focus on energy storage and leverage findings from two CPUC-commissioned energy storage procurement evaluation studies to address these reporting requirements. This report has three volumes: Volume I includes the CPUC Foreword to address the eight reporting requirements of Public Utilities Code Section 913.6 and the grid modernization updates from the three IOUs; Volume II "2023 CPUC Energy Storage Procurement Study"; and Volume III "2024 CPUC Scaling Up and Crossing Bounds: Energy Storage in California."

The Statutes Guiding This Report

Assembly Bill (AB) 242 (Holden, 2021) amended Public Utilities Code (PUC) Section 913.6 to create a new Grid Modernization Report requiring the California Public Utilities Commission (CPUC), in consultation with the California Independent System Operator (CAISO) and the California Energy Commission (CEC), to biennially report to the Legislature and the Governor on the progress made toward modernizing the state's distribution and transmission grid and the impacts of distributed energy resources (DER) on the state's distribution and transmission grid and ratepayers.

CPUC Decision (D.) 18-03-023 provides a framework for Grid Modernization and requires the IOUs to submit their 10-year vision for modernizing the grid when filing their General Rate Case. The CPUC adopted this definition of grid modernization in (D.)18-03-023:

> A modern grid allows for the integration of distributed energy resources (DERs) while maintaining and improving safety and reliability. A modern grid facilitates the efficient integration of DERs into all stages of distribution system planning and operations to fully utilize the capabilities that the resources offer, without undue cost or delay, allowing markets and customers to more fully realize the value of the resources, to the extent cost-effective to ratepayers, while ensuring equitable access to the benefits of DERs. A modern grid achieves safety and reliability of the grid through technology innovation, to the extent that is cost-effective to ratepayers relative to other legacy investments of a less modern character.[1]

1 D.18-03-023 Decision on Track 3 Policy Issues, Sub-Track 2 (Grid Modernization), p. 7

As part of this report, the CPUC requested the IOUs to submit Grid Modernization Progress Reports. These reports provide information on each IOU's technologies for DER integration, grid operation and reliability, and safety. For example, Southern California Edition (SCE) completed their technical implementation of Phase 1 base DER management capabilities in 2023, which allows them to monitor and dispatch DERs. Pacific Gas and Electric (PG&E) has recently launched their Grid Resource Integration Portal (GRIP)[2] to help planners and developers find information on potential project sites for DERs using map-based information that includes key data such as hosting capacity and load forecasts. San Diego Gas & Electric (SDG&E) completed their Supervisory Control and Data Acquisition ("SCADA") Phase 2 upgrade in 2023 to enhance testing capabilities of their distribution SCADA system which enables them to integrate additional grid sensing, switching and protection equipment from the control center. All three IOUs are continuing work on grid management systems, engineering software and planning tools, communications, and cybersecurity.

AB 2514 (Skinner, 2010) required the CPUC to evaluate the Energy Storage Procurement Framework established in D.13-10-040 and directed California's three large IOUs—PG&E, SCE, and SDG&E—to procure 1,325 megawatts (MW) of energy storage by 2020 with installation by the end of 2024. The decision also directed other load-serving entities to procure energy storage, adopted a framework to guide the storage procurement program and directed the CPUC's Energy Division to conduct periodic comprehensive evaluations of the storage procurement program. The CPUC met this requirement through two energy procurement evaluation studies, conducted by Lumen Energy Strategy with direction from the CPUC, and in consultation with the CAISO and CEC. Specifically, the CPUC storage procurement evaluation determined to what degree CPUC-directed energy storage procurements meet AB 2514's stated goals of grid optimization, renewables integration, and greenhouse gas emissions reductions. The first study, "CPUC Energy Storage Procurement Study" published in May 2023, aimed to learn from historical stationary energy storage procurements and operations and to assess the evolution of California's stationary energy storage industry both retrospectively and in the future. The second study, "CPUC Scaling Up and Crossing Bounds: Energy Storage" published in May 2024, continues the CPUC's examination of energy storage growth, performance in electricity markets, use cases, and policy pathways to unlock the full value from this flexible and modular resource.

Both the studies by Lumen Energy and the IOU grid modernization updates will be used to address the eight reporting requirements in PUC Section 913.6. Per PUC Section 913.6, this report shall evaluate the following:

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2 An upgraded version of PG&E's Distribution Resource Plan Data Portal

(a) On or before February 1, 2023, and biennially thereafter, the commission, in consultation with the Independent System Operator and the Energy Commission, shall report to the Legislature and the Governor on the progress made toward modernizing the state's distribution and transmission grid and the impacts of distributed energy resources on the state's distribution and transmission grid and ratepayers. The report shall evaluate all of the following:

> (1) Reliability and transmission issues related to connecting distributed energy resources to the local distribution networks and regional grid.
> (2) Issues related to grid reliability and operation, including interconnection, and the position of federal and state regulators toward distributed energy resource accessibility.
> (3) The effect on overall grid operation of various distributed energy resources.
> (4) Barriers affecting the connection of distributed energy resources to the state's grid.
> (5) Emerging technologies related to distributed energy resource interconnection and operation.
> (6) Interconnection issues that may arise for the Independent System Operator and local distribution companies.
> (7) The effect on peak demand for electricity.
> (8) The potential for distributed energy resources to benefit the state's distribution and transmission grid.

Assessment of Progress

The following discussion provides updates on the progress made toward modernizing the state's distribution and transmission grid and the impacts of distributed energy resources (DER) on the state's distribution and transmission grid and ratepayers, pursuant to the eight reporting requirements. This report focuses on energy storage as the central topic.

(1) California is adding energy storage at an unprecedented pace to support system grid reliability.[3]

System reliability and resource adequacy (RA) needs continue to drive significant growth in distribution and transmission connected energy storage capacity. Energy storage has quickly scaled to become a center piece of California's reliability procurement strategy, when both sited for local or system benefit and discharged during peak load periods.

By January 2020, there were about 150 MW of mostly large, Front-of-the-Meter storage installations operating in the CAISO marketplace which has increased more than seventyfold to over 10,983 MW by the end of December 2024.[4] More than 10,000 MW was procured for system reliability between 2020

3 Statute reporting requirement (1) Reliability and transmission issues related to connecting distributed energy resources to the local distribution networks and regional grid

4 CAISO Master Generating Capability List and CPUC NQC Lists. https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/summer-2021-reliability/tracking-energy-development

and 2024. In early 2022, the CPUC adopted the Integrated Resources Plan (IRP) 2021 Preferred System Plan which identified an additional 13,571 MW of battery storage plus 1,000 MW of pumped (long-duration) storage by 2032, suggesting an average build of 1,325 MW storage per year until 2032. In early 2024, at the conclusion of its 2022–2023 IRP cycle, the CPUC adopted the IRP 2023 Preferred System Plan where resources to meet reliability and greenhouse gas (GHG) reduction targets were updated to include 14,100 MW of new short-duration battery storage (mostly 4-hour), 500 MW of new pumped storage, and 400 MW of other new long-duration storage installed by 2032.[5]

The scale of reliability concerns differs between the distribution network and bulk transmission electric grid. Most customer outages are driven by hazards to and failures on the distribution system, while transmission-level outage risks are comparatively low.[6]

(2) and (3) The benefits of energy storage have evolved and increased over time which reduces renewable energy curtailments and improves grid reliability.[7]

Energy storage has become the workhorse of California's energy market, evolving from not only being a system level reliability resource but also being the catalyst in shifting energy loads and reducing renewable energy curtailments, thus supporting grid operations and the integration of renewable energy which is a critical pillar of California's climate goals.

Energy storage now provides various bulk grid level energy and ancillary services market benefits. During 2018–2020, the high revenue opportunities for providing spinning, non-spinning reserves and frequency regulation services in the CAISO market attracted many of the storage resources and resulted in the prioritization of 'grid reliability' use cases that are more focused on ancillary services. However, between 2022–2023, the share of storage capacity used for ancillary services declined, while the wholesale market value proposition for storage moved to bulk energy time shifting.[8] Most CAISO-participating energy storage resources now regularly charge at low-priced/low marginal emission periods in the day and discharge at high-priced/high marginal emission periods in the evening, thus mitigating the need to curtail renewable generation resources. This additional market use case has significantly improved the energy storage fleet's contributions to reducing GHG emissions, improving grid operations and reliability and facilitating renewable integration.

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5 *CPUC Scaling Up and Crossing Bounds: Energy Storage in California*, p. 16

6 *CPUC Scaling Up and Crossing Bounds: Energy Storage in California*, p. 7

7 Statute reporting requirements (2) Issues related to grid reliability and operation, including interconnection, and the position of federal and state regulators toward distributed energy resource accessibility; and (3) The effect on overall grid operation of various distributed energy resources.

8 CPUC *Scaling Up and Crossing Bounds: Energy Storage in California*, p. 21

(4) The CPUC has refined Electric Rule 21, which governs the interconnection rules for Distributed Energy Resources (DERs), by introducing cost-effective solutions like Limited Generation Profiles (LGP) and enhancing DER communication protocols to improve grid integration and flexibility.[9]

In 2024, the CPUC closed Rulemaking (R.)17-07-007, which refined and modernized rules under Electric Rule 21. Electric Rule 21 governs the interconnection, operating, and metering requirements for generation facilities to be connected to a utility's distribution system.

Some of the primary improvements adopted in the rulemaking include:

- Enabled Limited Generation Profiles to Reduce the Cost of Interconnection of DERs. Limited Generation Profiles (LGP) help to modernize the grid by allowing for faster, lower-cost deployment of DERs by avoiding grid upgrades that can take months or years to perform. LGPs allow DERs to operate safely within the confines of existing grid capacity limits. Resolution E-5296 detailed the scheduling requirements for Power Control Systems (PCS), which was the final step needed to implement the LGP option for interconnection customers. This adoption of PCS scheduling capability for LGP directly contributed to the development and uniform use of Underwriters Laboratory (UL) standard UL 3141 for PCS, a standard for compliance and safety integral to future grid modernization employing solar, battery storage, and other DER options.

- Enhanced DER Communication and Control and Future Interoperability. CPUC Resolution E-5357 facilitated grid modernization by addressing barriers associated with outdated DER communication and control protocols and the need for future equipment interoperability. The Resolution calls for updating the Common Smart Inverter Profile (CSIP), which was created by California's utilities under CPUC mandate to help implement the Institute of Electrical and Electronics Engineers (IEEE) standard IEEE 2030.5 for DER communications. The Resolution shifts responsibility for CSIP updates to third-party organizations, enabling more robust, universal, and expert-driven updates, leading to enhanced DER integration and grid flexibility. The Resolution also reduces challenges associated with equipment communications incompatibility, supporting future interoperability. The Resolution mandates the use of industry-wide standards for consistency, clearer certification using public instructions on how to test and certify products, and ongoing monitoring of national standard developments to ensure that communication requirements remain compatible with California's goals.

9 Statute reporting requirement (4) Barriers affecting the connection of distributed energy resources to the state's grid.

(5) Emerging technologies along with CPUC initiatives are improving the integration of distributed energy resources (DERs) into the grid by enhancing communication, operational flexibility, and optimizing grid capacity to improve grid stability with less infrastructure investment.[10]

Emerging software and hardware technologies such as Distributed Energy Resources Management System (DERMS), Advanced Distribution Management Systems (ADMS) and associated communication capabilities are required for facilitating reliable DER integration and effective grid and market operation. Utilities and third-party providers are actively developing new technologies to improve DER integration and grid optimization. The utilities require DERs to meet certain technology requirements through Electric Rule 21 discussed above.

The deployment and integration of ADMS and DERMS offer tools that improve the management of a more stable and reliable electrical grid. ADMS and DERMs allow grid operators to communicate with DERs with increased speed as well as establish protocols to optimize DERs by utilizing features such as anti-duck curve scheduled dispatch, power factor limiting, fast frequency response, and others.

The CPUC initiated the Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future (R. 21-06-017) in 2021 to prepare the electric grid for a high number of connected DERs. In the Smart Inverter Operationalization and Grid Modernization Planning track of the rulemaking, the CPUC tasked a technical working group with identifying Smart Inverter Operationalization (SIO) use cases that best leverage the capabilities of smart inverters to provide value to grid operators and ratepayers. The Smart Inverter Operationalization Working Group (SIOWG) report identified the specific communications and DERMS requirements as well as rules and guidance on utility dispatch of DERs and aggregators to achieve the use cases.

The SIOWG report identified operational flexibility as the topmost stakeholder priority.[11] This relates to IOUs ability to use operational flexibility to optimize capacity utilization in a high DER future landscape. Operational flexibility may lower grid infrastructure investments while ensuring grid safety and reliability. An example is Flexible Connection Agreements (FCAs) to help accelerate customer energization timelines. A key benefit of FCAs, sometime called a "bridge to wires", is offering energization applicants the option to energize sooner by operating below their maximum requested load temporarily while IOUs build additional upstream capacity needed to meet the full load.

10 Statute reporting requirement (5) Emerging technologies related to distributed energy resource interconnection and operation.

11 Smart Inverter Operationalization (SIO) Working, Group Report, Business Cases and Use Cases, February 1, 2024. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M532/K694/532694061.PDF

(6) The CAISO generation interconnection queue includes more generation projects than are needed to meet state goals, and recent CAISO reforms help to focus on priority projects that are aligned with state resource planning and procurement.[12 13]

In 2023, the CAISO launched a policy initiative to reform its generation interconnection processes. At the time, the CAISO interconnection queue contained more than three times the capacity expected to achieve California's 100% clean energy policy objective in 2045. Reforms were essential to advance the most viable projects toward interconnection and commercial operation and to prevent stagnant projects from hindering the progress of viable projects in the queue.

On September 30, 2024, the Federal Energy Regulatory Commission (FERC) approved reforms to the CAISO's interconnection processes to help streamline both interconnection queue intake and management of projects moving through the interconnection queue.[14] The CAISO continued to reform its interconnection processes with a third track that was approved by the CAISO Board of Governors in March 2025.[15] These reforms help projects aligned with state and local resource plans and located in areas, or zones, with transmission availability to proceed through the CAISO interconnection queue.

Since implementation of the reforms approved by FERC in 2024, there has been a material reduction of projects in the CAISO interconnection queue, which will help streamline the CAISO's interconnection study process going forward.

Both the CAISO interconnection queue and research conducted by Lawrence Berkeley National Lab (LBNL) highlight that, in both absolute and relative terms, energy storage capacity in the CAISO interconnection queue exceeded that of all other centralized wholesale market areas in the U.S. Thus, the CAISO's interconnection reforms are critical to help advance the most viable projects in areas that align with local and state resource planning and procurement.

By prioritizing projects located in zones with existing or planned infrastructure and/or projects with commercial viability that have a signed or near-signed power purchase agreement, ratepayers can avoid paying for generation that is not located in priority areas or not cost-effective.

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12 "The CAISO interconnection queue now contains more than three times the capacity expected to achieve California public policy objectives for the next two decades and far exceeds the ability of available and planned transmission to deliver power from all of these projects to customers." (CAISO's tariff amendment submittal to FERC, https://www.caiso.com/documents/aug-1-2024-tariff-amendment-interconnection-process-enhancements-2023-er24-2671.pdf.)

13 Statute reporting requirement (6) Interconnection issues that may arise for the Independent System Operator and local distribution companies.

14 Federal Energy Regulatory Commission - Order on Tariff Revisions issued September 30, 2024.

15 https://www.caiso.com/documents/decision-on-interconnection-process-enhancements-track-3-memo-mar-2025.pdf

(7) Behind-the-meter (BTM) energy storage paired with solar can help reduce peak electricity demand and greenhouse gas emissions by charging from solar and discharging during on-peak hours[16]

BTM DERs can reduce peak electricity demand by decreasing or time-shifting on-site demand and by increasing the supply of renewable generation by storing and then exporting to the grid during peak hours. There are two peak periods of concern to grid operators: 1) the 'gross' peak, when overall demand is at its highest and 2) the 'net' peak, when overall demand minus renewable supply sources is highest. In California, the electricity grid's gross load peak occurs in late afternoon when consumers' demand for energy increases due to diminishing roof top solar during that time of day. In summer, especially during high heat events, solar production is often declining when temperatures are still hot and air conditioning demand remains high, which means that the critical time for the grid can occur close to sunset.

To close the gap during this period for the grid, the CAISO must find other resources, including imports, to meet demand no longer being served by solar resources. The growing capacity of storage resources helps fill this need to reduce net peak demand through an 'energy time shift' by charging from renewable generation during off-peak hours and discharging during on-peak hours when grid GHG emissions and energy prices are the highest.[17]

The SGIP Impact Evaluations[18] show that behind-the-meter (BTM) energy storage provides the greatest peak reduction and customer bill reduction benefits when paired with and charging from photovoltaic (PV) arrays during PV generating hours and discharging during on-peak hours. Utilizing the onsite PV to charge the storage rather than exporting it in the middle of the day increases the bill savings for customers. Standalone energy storage systems also typically discharge during similar on-peak hours, either to benefit from export compensation or to avoid import costs by serving on-site demand.

To receive an SGIP incentive, BTM energy storage systems are prohibited from operating solely in a backup operating mode and only being utilized during power outages, without regular cycling. Incentivized systems must meet a minimum annual cycling requirement to ensure that the batteries are regularly charging and discharging. The customer must also be on a time-of-use (TOU) electric rate to ensure that they are appropriately incentivized to conduct energy arbitrage. These requirements contribute to reductions in net peak electric demand by ensuring that energy storage systems are regularly reducing onsite demand from 4-9 pm daily or exporting to the grid during this period to take advantage of export rates.

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16 Statute reporting requirement (7) The effect of DERs on peak demand for electricity.

17 *CPUC Energy Storage Procurement Study*, p. 13

18 Verdant Associates. (2024, May 29). *SGIP 2021-2022 Impact Evaluation Report.* https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/self-generation-incentive-program/sgip-2021-2022-impact-evaluation.pdf

While BTM solar and storage do help reduce peak demand for electricity it is important to recognize the high cost of these resources compared to other available resources. In evaluating the preferred system portfolio for procurement, BTM solar and storage are not selected as resources needed to serve future load or meet climate change goals.

Furthermore, because of the cost shift of rooftop solar and storage systems, BTM systems continue to result in significant costs for non-solar ratepayers by an average estimated $230–$380 per year per customer in 2024.[19] "Cost shift" refers to increased costs for non-solar customers because solar ratepayers under net metering programs avoid paying some of fixed electric grid costs and receive retail-rate credits for exported power, leaving remaining non-solar ratepayers to cover a larger share of utility expenses.[20] The adoption of the Net Billing Tariff (NBT) helps reduce but does not eliminate the cost shift.

19 California Public Utilities Commission. *2025 Senate Bill 695 Report*. Sept. 2025, p. 3

20 California Public Utilities Commission. *2025 Senate Bill 695 Report*. Sept. 2025, p. 42

(8) California's BTM storage has expanded dramatically since the replacement of NEM 2.0 with the Net Billing Tariff in April 2023 which utilizes hourly-based price signals to accurately value and thus incent dispatch of storage when it has the greatest avoided costs to the grid based on a full spectrum of quantifiable benefits, including avoided transmission and distribution costs.[21]

The CPUC's Avoided Cost Calculator (ACC) calculates the avoided marginal cost of reducing (or increasing) energy usage in each hour of the year for the next 30 years. These avoided costs are determined by a value stack which includes avoided transmission and distribution marginal costs. While there are sizable benefits to T&D deferral in key high-demand summer evening hours, the net deferral value has been found to be relatively low for BTM solar in general. This is largely because the system peak has shifted well past optimal solar hours and into the evening. As a result, many BTM solar customers with bidirectional energy imports/exports may use the transmission and distribution system *more* during the middle of the day while their load reduction grid impact during peak hours are largely negligible. In part because of this, the CPUC implemented the Net Billing Tariff in April 2023 to create highly granular ACC-based price signals that incentivize BTM solar customers to add battery storage to store their excess solar production during the middle of the day and either reduce their own demand in the evening or export excess energy to the grid in the evening when it is most valuable for greenhouse gas reductions and grid costs. This more accurate pricing model not only better utilizes BTM solar and storage, it also reduces the cost burden on low-income California ratepayers. Since the implementation of the Net Billing Tariff, paired BTM solar plus storage rates increased from roughly 13% to roughly 69%.[22] Through accurate price signals, the potential of BTM storage are being optimized for the state's transmission and distribution grid while reducing inequitable burdens on low-income customers. Note that the vast majority of BTM solar customers, who still are within their 20-year legacy period of NEM1 and NEM2, do not have these price signals.

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21 Statute reporting requirement (8) The potential for distributed energy resources to benefit the state's distribution and transmission grid.

22 California Distributed Generation Statistics (DGStats). https://www.californiadgstats.ca.gov/

Remaining Sections of This Report

In addition to providing updates on progress made by the CPUC, CAISO, and CEC on these topics, the following sections of this report include Grid Modernization Progress Reports detailing implementation by the three IOUs, followed by summary information on the "CPUC Energy Storage Procurement Study" and "CPUC Scaling Up and Crossing Bounds: Energy Storage," which provide focused information on the benefits and effects of energy storage to the state's grid.

In summary, this Grid Modernization Report provides updates on the progress made toward modernizing the state's distribution and transmission grid and the impacts of distributed energy resources (DER) on the state's distribution and transmission grid and ratepayers. This report addresses the eight reporting requirements set forth by the PUC Section 913.6 by focusing on energy storage as its central topic.

PG&E GRID MODERNIZATION UPDATES

PG&E's Grid Modernization

Progress Report

April 24, 2024

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I. Introduction

California is a leader in the growth of Distributed Energy Resources (DERs) including solar, battery storage, electric vehicles, and demand response. This progress is driven by a confluence of technology advancements, consumer preferences, and complementary legislative and regulatory actions in the state. Moreover, increasing climate-related risks have also accelerated the proliferation of resilience-focused DER solutions in California. PG&E plays a central role in enabling the safe and continued adoption of DERs. As of December 31, 2022, PG&E has interconnected over 700,000 Behind-the-Meter (BTM) Solar PV systems (~7 GW) over 50,00 BTM batteries (~500 MW) and ~400,000 electric vehicles.

While DERs may help achieve California's clean energy and resilience objectives, they may also potentially create new challenges and complexity on the grid including capacity constraints, power quality issues, and adverse impacts on protection systems due to bi-directional flow. In addition to the electrical complexities, there are programmatic and policy requirements that also need to be managed as the rules and regulations around DERs in PG&E's service territory continue to evolve.

Modern Operational and Planning tools and capabilities form an essential foundation for PG&E to achieve a secure, reliable, and affordable electric grid that enables clean energy and California's economic interests while providing maximum flexibility and value for customers. The goal of PG&E's grid modernization effort is to meet today's challenges while also positioning the grid to meet the demands of a dynamic energy future with improved situational awareness, operational efficiency, cybersecurity, and DER integration and orchestration capabilities.

II. Highlights of PG&E's Grid Modernization Activities in 2022-2023

This section shares PG&E's grid modernization activities and deployment projects done in 2022 and 2023.

A. Grid Management Systems

1. Advanced Distribution Management System (ADMS)

The ADMS is PG&E's core distribution operations software tool to enable visibility, control, forecasting, and analysis of a more dynamic grid. When fully deployed, the platform will bring the capabilities of today's Distribution Supervisory, Control and Data Acquisition (D-SCADA), Distribution Management System (DMS), and Outage Management System (OMS) applications into a single, integrated platform and enable many new capabilities.

The ADMS is a foundational tool that will bring far-reaching benefits to PG&E, its customers, and the distribution system. Some of the capabilities enabled by ADMS include:

- Reduced cybersecurity risk from replacement of PG&E's legacy RT-SCADA system

- Labor efficiencies from automated switching recommendations, automated switch log development, and consolidation of functionality into a single application and screen
- Reliability improvements from instantaneous fault location, automated switching recommendations, and enablement of more flexible, model-based Fault Location, Isolation, and Service Restoration (FLISR) schemes
- Improved safety from streamlined internal processes and automated detection and mitigation of overload conditions on non-telemetered points on the distribution grid
- Better quality of communication to customers during outages
- Energy savings, peak demand reduction, and greenhouse gas emissions reductions from future ADMS-managed automated Volt Var Optimization (VVO) schemes
- Improved management of Distributed Energy Resource (DER)-related grid issues through awareness of masked load associated with DER generation and the automated mitigation of DER-related thermal, voltage, and protection issues
- Enablement of Distributed Energy Resource Management System (DERMS) functionality such as the proactive dispatch of DER to mitigate real-time and forecasted grid constraints identified via the ADMS

PG&E has divided its ADMS implementation into three main “releases”, which are described in more detail below.

- **ADMS Release 1:** The scope of ADMS Release 1 is to replace PG&E’s legacy RT-SCADA system with an ADMS-based SCADA system that is integrated with PG&E’s network model. Scope for ADMS Release 1 also includes replacing PG&E’s legacy Yukon Feeder Automation (YFA) FLISR software with a native ADMS FLISR product, developing ADMS functionality to support PG&E wildfire risk mitigation efforts such as reclose blocking, implementing the Operator Training Simulator (OTS) in ADMS to assist with new Operator training.
- **ADMS Release 2:** The scope of ADMS Release 2 is to replace PG&E’s current outage management applications with OMS functionality in ADMS including outage planning, calculation of outage location and extent, crew dispatch, customer outage notification, switch log generation, and reliability reporting in a single vendor-supported product. ADMS will replace the highly custom-built and complex ecosystem of outage management applications PG&E uses today that is costly to maintain and challenging to integrate.
- **ADMS Release 3:** The scope of ADMS Release 3 is to enable Advanced Applications within the ADMS platform. PG&E’s initial focus for Release 3 will be enabling foundational integrations with Line Sensor data and implementing Enhanced Powerline Safety Setting (EPSS) and Fault Calculation functionality. PG&E’s focus will then shift to enabling Load Flow/State Estimation and Forecasting capability, which provide the ability to model real-time and predicted future power flows at any location on the distribution grid using a combination of SCADA telemetry, physical properties of network features stored in GIS and CYME, device settings stored in PowerBase, and the as-switched state of the grid as maintained in ADMS. These foundational capabilities enable many additional advanced applications on PG&E’s future roadmap including:
    - Identification of real-time and predicted future grid constraints
    - Automated switching recommendations for outages or constraint mitigation

  - Fully automated FLISR schemes, allowing faster and more flexible service restoration than PG&E’s current “rule-based” FLISR
  - Automated adjustment of voltage and power factor regulation device settings (Volt-Var Optimization)
  - Automated adjustment of protective device settings (Adaptive Protection)

Work on ADMS Release 1 during the twelve months ending in March 2024 was highlighted by the following activities:

- Cutover 8 out of 19 PG&E operating divisions to the ADMS SCADA platform
- Cutover of rules-based FLISR capabilities on the ADMS SCADA platform
- Cutover of Load Shedding functionality to the ADMS SCADA platform
- Conducted pre-cutover field point-to-point testing of SCADA signals to ensure accuracy of signal mapping into the network model
- Successful maintenance of the ADMS Network Model by the newly established ADMS support team
- Deployed regular maintenance patches and updates to the ADMS SCADA systems containing issue fixes and additional functions

Delivered continued ADMS refresher training to Operator and Engineer end users of ADMSADMS Release 1 is scheduled to conclude later in 2024 after D-SCADA functionality is cutover to the ADMS platform for the remainder of PG&E’s operating divisions.

The team is also underway with delivery of ADMS Releases 2 & 3 which had previously kicked off in parallel to Release 1. Work on ADMS Releases 2 & 3 during the twelve months ending in March 2024 was highlighted by the following activities:

- Continued the Design and Build phases of the Release 2 & 3 Network Model, which will extend the existing ADMS Network Model to include the low voltage network, customer data, load profile data, and new device settings information
- Completed the Plan & Analyze Phase for Release 2 and finalized a detailed implementation plan for the Design, Build, Test, and Cutover Phases
- Started development of key systems integrations required for Release 2
- Completed Design activities for Release 2 Planned Outage functionality and portions of Unplanned Outage functionality
- Completed Plan & Analyze activities for Release 2 PSPS functionality
- Finished contract negotiations for the System Integrator, Business Integrator, Network Model, and Product Vendor roles for Release 2
- Completed Design activities for Release 3 Enhanced Powerline Safety Setting (EPSS) functionality to be built within ADMS
- Completed Plan & Analyze activities for Release 3 Line Sensors data integration and Load Flow/State Estimation functionality
- Supported Release 3 Microgrid Enablement functionality through the Redwood Coast Airport Microgrid (RCAM) SCADA screen build
- Supported Plan, Analyze & Design activities for the 2030.5 IEEE protocol enabled by the DERMS platform

This work has set PG&E on a course for the continued success of Design, Build, and Test activities related to ADMS Release 2 & 3 functionality in 2024-2025. The Go-Live date for ADMS Release 2 is scheduled to occur in 2026. The Go-Live date for ADMS Release 3 EPSS functionality is scheduled to occur in 2024, with additional Release 3 functionality deployments anticipated in subsequent years.

2. Distributed Energy Resource Management System (DERMS)

PG&E's Enterprise Distributed Energy Resource Management System (DERMS) will complement the foundational technology improvements and grid management tools built by the Advanced Distribution Management System (ADMS) program. The DERMS will allow PG&E to manage the added operational and programmatic complexity of ever-growing Distributed Energy Resources (DERs) and DER Programs on the PG&E grid. PG&E will build a DERMS platform to deliver the following capabilities:

- Full integration with ADMS – DERMS will seamlessly integrate with the ADMS, building on the integrated network model and grid modeling capabilities provided by the core ADMS product.
- DER advanced situational awareness for normal and abnormal conditions – DERMS will provide additional DER visibility beyond what is typically included by an ADMS such as DER status, flexibility, availability, forecasted flexibility, and program insights.
- Monitoring, dispatch, and program management of DER systems – DERMS will be a secure platform that enables the monitoring and dispatch of both front-of-the-meter (FTM), behind-the-meter (BTM), and aggregated DER assets with rules based on program types.
- DER constraint management for interconnection and abnormal conditions – DERMS will manage constraints on DERs including a limited generation profile, and other more dynamic constraints including during abnormal grid configurations due to outages or planned work. DERMS will also help manage DER impacts at the Transmission and Distribution interface including coordination of wholesale market participants on the Distribution system and enable more dynamic hosting and load serving capacity.
- Operation of DER-based deferral solutions - Examples of such solutions include projects participating in the Distribution Investment Deferral Framework (DIDF) and other alternatives to conventional infrastructure investments. As the number of these projects expand, platform-based controls and processes will increase the efficiency to manage the dispatch, mitigations, and settlements of these systems.

In 2023, PG&E deployed the first phase of an enterprise DERMS providing a foundational cloud-based platform integrated with ADMS. This DERMS platform replaced the existing DER Headend deployed through the Electric Program Investment Charge (EPIC) Project 3.03 which was based on PG&E's legacy SCADA vendor that is now being transitioned to the new ADMS platform. This function enables cybersecure communications between utility systems and third party owned DERs leveraging the Institute of Electrical and Electronics Engineers (IEEE) 2030.5 protocol and the SunSpec Common Smart Inverter Profile (CSIP), and is available for all DER interconnection customers with 1MW or greater DERs. This enables DER customers to use their own certified-interoperable devices to fulfill their interconnection telemetry requirement at a lower cost than was possible with the existing options for PG&E installed, owned, and maintained telemetry equipment.

This DERMS communication platform using IEEE 2030.5 will also be leveraged for planned automated DER control testing in 2024, with an initial focus on use cases related to managing dynamic distribution grid constraints with enhanced situational awareness of grid conditions, operational forecasts of grid conditions in the hours/days ahead, and control of participating DERs including flexible loads.

These particular use cases are driven by existing capacity constraints and the timelines required for PG&E to build infrastructure to support the full load requests of customers, for example, large EV charging stations. In 2024, PG&E will be piloting DERMS functionality to establish capacity allowances for constrained customers with flexibility based on day-ahead hourly forecasts versus the status-quo planning processes that are often limited by the worst times of the year. This is expected to allow customers to connect more quickly while unlocking significant additional capacity for them by better utilizing PG&E's existing assets based on near-term load forecasts. DERMS will provide a bridge solution for these customers until the scheduled PG&E work is completed, which can sometimes be more than a year.

Initial lab testing completed in 2023 involved the baseline modeling, forecasting, and control functionality in DERMS, however, more testing and enhancements are required and planned prior to field testing in the second half of 2024. PG&E plans to field test at a limited scale (<10 sites) in 2024 flexible service connections and to operationalize PG&E's first Distribution Investment Deferral Framework (DIDF) project. Pending the results of these tests, PG&E will use learnings to modify the system, processes, and plans to scale DERMS functionality in subsequent years.

B. Communications and Cybersecurity Infrastructure

1. Communications Networks

PG&E owns and operates a large private network to service the needs of its critical operations for the Grid, Pipeline and Generation locations and personnel. It is augmented by public networks from the carriers for redundancy, enhanced coverage, less critical applications. PG&E includes the investments of the lifecycle and enhancements to these networks in the General Rate Case.

The pertinent work that PG&E has been investing in support of the Grid Modernization Plan in 2021 and 2022 and in alignment with the GRC submittal is as follows:

- Field Area Network. PG&E is continuing the installation of the Field Area Network (FAN) mesh technology as a means of increasing the data capacity, volume of devices, cyber security and remote management of grid devices. Currently, 4000 filed nodes have been installed to support SCADA enables devices managed through ADMS.

- Satellite Communications. This 3rd party service has been and continues to be deployed in more remote areas of the service territory where private networks are not economically feasible to build and where cellular networks are not available. Aside from grid devices, this technology has been used for Weather stations in support of Wildfire Threat Area situational awareness. 1300 such connections have been procured and installed.
- Cellular Connections. With the proliferation of AT&T's FirstNet and Verizon's Frontline cellular services, PG&E is taking advantage of the higher priority cellular networks and installing more SCADA devices where this service is available.
- Fiber Optic Cable Replacement. PG&E has been investing in lifecycle replacement of existing aging fiber optic cables which service the network backbone needs with high capacity.
- Lifecycle Replacements. PG&E has engaged in replacing technically obsolete communications equipment to improve the overall health, reliability, and maintainability of our communications transmission infrastructure, migrating to IP based communications. PG&E has also continued its efforts to maintain the health of its IP based routed MPLS network at the critical core operating centers and substations.
- Monitoring Tools. Additional tools have been added to consolidate functionality that was previously disparate and difficult to integrate. This improves our situational awareness and predictive event management to effectively manage a critical private network.

2. Architectural Considerations for DER Connectivity

The communications network considerations for the DER connectivity need to take into account all the requirements for a comprehensive set of data needs at a DER location, inclusive of the following: the DER core functionality (transacting with DERMS), non-functional overhead data such as cyber protocols, device remote management, communications network performance management, access control, as well as supporting native local applications such as analytics, batch reports and distributed computing needs. Additional data requirements stem from the environmental instruments at the DER location, such as physical alarms, cameras, fuel levels, weather stations, etc.

The second level of communications Network considerations is attributed to the network resiliency requirements of the DER. This would be driven by the physical location and reach, size of DER and its importance to the grid. These types of considerations drive the network designs in terms of number of redundant network paths, mediums, constructability limitations, and availability of third-party communications service providers.

The basic premise of the communications network is IP based protocols to accommodate all the device, data and security requirements. Migrations to IP based communications enable many functions not available today such as remote software updates, increased data acquisition, and configuration updates. As these devices are converted to IP based communications and data requirements increase PG&E will need to continue to invest in new technologies to meet the growing demand. It is likely that PG&E will need to deploy emerging technologies such as private LTE, other private radio systems, and increased public carrier technologies (cellular, satellite, and leased services).

Many DERs of smaller size today are well serviced through internet connections as well as cellular services while utilizing the secure protocols described below. PG&E would only extend its private network to DER assets that it owns and operates. This private network is not considered for public DERs.

3. Cybersecurity Developments with the DER proceedings

As part of the continued work for DERs in the Rule 21 proceeding, the IOUs established a goal for the creation of the "Utility Cybersecurity Requirements Guide for Communication to DER Facilities".[1] IOU and stakeholder weekly meetings were held to discuss development of cybersecurity recommendations with final publication of the guide in the Interconnection Handbook in August 2021. In early 2022, the Smart Inverter Operationalization Working Group (SIOWG) was launched with the scope of formulating business use case prioritization. A sub-group of SIOWG was created to discuss an approach for a cybersecurity workstream. The subgroup has concluded its work and developed a working group report that includes assessment of IEEE 1547.3 and cybersecurity recommendations along with proposed regulatory guidance for the CPUC. This stakeholder effort contributed to addressing cybersecurity considerations for endpoints. This effort contributed to the development of technical standards for cybersecurity of DERs and furthers discussions for potential development of broader standards for DER stakeholders.

4. Enhanced Cybersecurity controls for ADMS

Cybersecurity controls and requirements were taken into consideration during the early design phases of Advanced Distribution Management System (ADMS) deployment. Thus, PG&E have a modern distribution grid management platform with cybersecurity embedded and not bolted-on. PG&E ADMS implementation involves extremely granular segmentations and access control both at the network and application layer. ADMS platform is implemented with multiple dedicated security directory services from Microsoft and next generation Palo Alto application aware firewalls. ADMS compute resources are subjected to continuous monitoring by the enterprise Security Information and Event Management (SIEM) platform. All remote administrative interactions with the system are brokered and monitored. Other cybersecurity capabilities extended to ADMS infrastructure includes Tenable for vulnerability management and Forescout EyeInspect for SCADA device monitoring and anomaly detection.

5. Cybersecurity for Integrated Grid Platform

[1] Rule 21, Smart Inverter Working Group Phase 2 Recommendations, Communication Requirements

Improving Operations Technology (OT) Cybersecurity will benefit PG&E, our employees, and the communities we serve. More than ever before, PG&E's Operations Technology (OT) asset landscape is being transformed considerably due to the accelerated adoption of connected smart devices with modern connected technologies. PG&E recognized the need for not to rely only on rule-based solutions but heuristic approach for early detection and alerting of anomalies in the SCADA network. This paved way for a new strategy and PG&E launched a multi-year Advanced OT (Operations Technologies) Cybersecurity program in 2019.

Key outcome - *Reinforces PG&E business values*

- Protects against an increasing, ever-evolving threat (e.g., energy sector targets on the rise, potential risk of grid control compromise, individual site takedown, or some variation)
- Addresses vital OT security needs, not just compliance (NERC CIP is a minimum baseline for limited # of assets)
- Comprehensive OT asset inventory – device properties/classification, configuration, and network context. Enable Vulnerability assessment of OT devices
- The baseline of normal communications for both IT and ICS protocols in the ICS network. Mathematical model of network life or pattern to define normalcy
- Consolidated and streamlined Alert ingestion (Integrations with asset management and SIEMs
- Multi-layer anomaly with real time alerting capability on critical and process impacting events. Ability to detect unusual engineering port, unusual time of the day, etc

The program kicked off with a pilot deployment at 10 critical Electric Transmission and Distribution sites including control centers and data centers. The program executed subsequent projects to deploy the solution at all High, Medium and low NERC sites along with critical Distribution substations.

Further, the migration from legacy SCADA to ADMS significantly enhanced the security posture by enabling centralized OT asset enumeration capabilities from Cybersecurity point of view.

6. Operational Data Network (ODN) Security Program

ODN is the industrial control system network at PG&E. ODN security program is designed to mature cybersecurity industry best practices as part of the design, build, and implementation of the new/enhance security capabilities. To enable these best practices, certain technological investments have been put in place that includes firewall upgrades, expansion and fine tuning of OT asset discovery and anomaly detection. The design and onboarding of Endpoint Detection and Response (EDR) capabilities in the OT network will significantly improve security posture of cyber assets supporting grid operations.

PG&E identified need for improving configuration management capabilities in ODN. Ansible platform was chosen to bridge the gap of Tripwire platform that serves as configuration management tool.

This investment track also enabled the design, development and adoption of NERC ECAMS capability for virtualized computes resources.

7. SORT – Security Intelligence Operations Center OT Monitoring and Response

To improve the Security Intelligence and Operations Center (SIOC)'s operational response capabilities, we have created the SIOC Opsec Response Team (SORT). This team's primary focus is on cyber threat detection and response capabilities within the OT networks at PG&E. The individuals on the team have received external training and certification (CISA/INL 301 and SANS ICS515/GRID) and are additionally working with the functional areas of the business to build relationships, understand their business processes, and develop our own response playbooks. The deployment of additional tools, such as ICS-tailored passive network monitoring and EDR, are being deployed and will further strengthen SORT's abilities to detect and respond to threats in PG&E's OT networks.

C. Engineering Software and Planning Tools

Modernization efforts for PG&E’s engineering and software planning tools include:

- **Distribution Resources Plan (DRP) Tools:** The DRP required the creation and use of new tools, including Integration Capacity Analysis (ICA), the DRP Data Portal, and the ongoing analysis and publication of distribution data via the Grids Needs Assessment (GNA) and Distribution Deferral Opportunity Report DDOR annual reports:
    - ICA – The objective of ICA is to simulate the ability of individual distribution line sections to accommodate additional DERs without potentially causing issues that would impact customer reliability and power quality. PG&E has worked with a third-party vendor to operationalize ICA and incorporate intelligent quality control into the ICA process. The Rule 21 Interconnection Process has adopted the use of ICA. On select circuits monthly, ICA is performed, results are validated as-needed, circuit models are updated as-needed, and results are published.
    - DIDF – The annual Distribution Investment Deferral Framework (DIDF) includes the publication of the GNA and DDOR, hosting of Distribution Planning Advisory Group (DPAG) meetings, and coordination with an Independent Professional Engineer (IPE) and Independent Evaluator (IE).
        - The objective of the GNA is to provide transparency into the assumptions and results of the distribution planning process that yield the Candidate Deferral Opportunities shortlist, propose grid modernization investments, and proactive hosting capacity upgrades

proposed to accommodate forecast DER growth. PG&E’s GNA presents data available regarding PG&E’s projected distribution grid needs over a five-year planning horizon.

- The objective of the DDOR is to utilize the GNA to identify PG&E’s candidate distribution deferral opportunities shortlist. In addition, other objectives of the DDOR are to provide transparency into the assumptions and results of the distribution resources planning process that yield the DDOR candidate shortlist and provide the associated DER attributes required to meet these opportunities.

- DRP Data Portal – The DRP Data Portal is an externally-facing, map-based portal that provides information about PG&E’s distribution network, including ICA, GNA, and DDOR results.

- **Planning Tools Driven by DRP Compliance:** The scale of the data and analysis within the DRP requires specific and customized tools to process and ensure data quality and accuracy. GNA and DDOR requirements from the DRP require PG&E to make upgrades to existing planning tools, including the CYME application and the LoadSEER application. These items are driven by three main objectives: a) eliminating manual analysis and processes through automation, minimize manual application integration, and manage analysis complexities.
- **CYME Substation Modeling and Analysis:** This project will further model the substation within CYME, including but not limited to transmission protective devices at the interface between transmission and distribution, transformer banks, substation buses, and distribution breakers. Adding new substation components into the CYME model will allow for additional analyses to be performed within the CYME application. The current process requires engineers to do some of the substation-level analyses outside of CYME, either in separate protection analysis tools, spreadsheets, or on paper. Further incorporating the substation model into distribution planning software allows engineers to further study within CYME bank and feeder level upgrades, bank and feeder loss studies, substation elements of the distribution protection studies, and bank and feeder capability ratings.
- **Distribution Time-Series Analysis Phase 2:** This project will build upon the successful implementation of the CYME Time-Series Load Flow Analysis project and further automate the distribution planning process. This project will extend the existing time-series analysis to assist with Voltage Regulator and Capacitor optimization and Risk Prioritization. Additionally, this project will investigate the use of the Advanced Project Manager (APM), results from the time-series analysis, and the technoeconomic analysis module to generate standardized and templated project authorization documentation.
- **Distribution Planning Automation:** The Distribution Planning Automation project will develop a manage-by-exception analysis process within CYME for capacity planning study deficiencies. Circuit analyses will be initiated and reviewed at the dashboard level, allowing engineers to focus their review on circuits with forecasted deficiencies. Distribution planning tools will also be further integrated with two-way information flow.

The status of these projects are as follow.

- **DRP Tools:**
  - DIDF: PG&E has successfully published the GNA and DDOR Reports annually for the last six years. These reports contain over 1 million data points and include written assessments that provide transparency into PG&E's annual Distribution Planning Process (DPP). Through the DIDF process, PG&E has successfully procured, through third party vendors, 4 contracts for ~4.0 MW of distribution deferral services to replace or defer traditional wire-based projects in the Company's project planning pipeline.
  - ICA: The real-time use of Integration Capacity Analysis data within the interconnection application process of Rule 21 projects over 30 kW was implemented in September, 2022. Updates to the application system include:
    1. The ability for customers to use a typical solar photovoltaic (PV) profile for their interconnection application, instead of using the device nameplate capacity, which may allow for interconnection of larger PV projects, potentially increasing the proliferation of renewable power onto PG&E's grid.
    2. Consolidation of all generator interconnection applications and applications for service into one website including a refreshed dashboard with self-service abilities for customers to see project status down to the task level and any outstanding application issues.
    3. The ability for customers to check the available feeder capacity at a specific location and to see real-time Integration Capacity Analysis data within the application portal enabling a more accurate, efficient, and transparent assessment for interconnecting renewable DERs.
    4. Automated import of Integration Capacity Analysis values for Rule 21 projects over 30 kilowatts (kW).
    5. Direct link to refreshed maps to help applicants find information on potential sites for DERs. The maps show hosting capacity and other information about PG&E's electric distribution grid (Integration Capacity Analysis Maps). PG&E is working to add hosting capacity map information directly within the application portal, which will be more convenient to use and further streamline the process for customers.
- **Integration Capacity Analysis (ICA):**
  - PG&E has submitted its ICA Refinements Annual Report[2] in Q4, 2023. The load ICA refinements project is on track as scheduled and expected to be operational by the end of Q4, 2024. The progress, timelines, milestones, challenges and roadblocks, and solutions are provided in detail in the report. The ICA refinements will be built upon the features offered by the Long-Term Planning Tool (LTPT) and new version of LoadSEER described in the next sections. These include the load application database, projects database, and the ability to query 576 hours load forecast data at premise level. The future looking load information could include "DER forecast" and "load forecast". PG&E expects the Development phase to continue into Summer of 2024. This

[2] PG&E's ICA Refinements Annual Report, December 12, 2023

includes developing the software codes, web platforms, IT environments, creation of new data structures in databases, building of data and system interfaces, and identification of new procedures to support on-going maintenance. The Testing and Deployment phase will commence through Fall of 2024 and will happen at different stages of product development and deployment. The Support & Stabilization phase will take place throughout 2024 to monitor performance of the platform and ensure that the new stablished processes are stable.

- PG&E has been working on ICA methodology improvements on an ongoing basis, this includes but not limited to adjusting voltage fluctuations criteria to comply with IEEE standards, incorporation dynamic calculations of ICA limits for different voltage levels, modifications to processes and systems of record, automation of Rule 21 Screen L calculations and its publication on ICA portal, etc.
- PG&E has been identifying additional opportunities to modify the future ICA methodologies above and beyond the compliance requirements, this includes but not limited to modifications of the new study triggers, network hierarchy modelling to reduce unnecessary complexities, expedite calculations, and improve accuracy, modifications to voltage regulating devices modelling methodologies, parallel computing, exploring new database options to store historical data and reduce operational costs, etc.
- Rule 21 Limited Generation Profile (LGP) Use Case: LGP customers will be able to upload a 288-hour export profile into the PG&E application portal (12 month, 24 hours a month) in CSV format. These profiles will be treated as a separate category of generation and used as inputs for ICA calculations. Currently, the requirements have been captured and documented in the ICA refinements project but not implemented yet.
- PG&E has worked with CYME to identify a solution to reduce convergence issues associated with device status oscillations as recommended by ITE and reported in PG&E's supplemental advice letter for data validation plan. CYME's modified power-flow engine in CYME 9.3 Rev2 addressed voltage regulating device divergence issues identified in the previous statistical analysis, which is now used by PG&E to perform ICA calculations.
- PG&E has recently added a new interface on the public ICA map that indicates whether a desired location is expected to have capacity. This serves as an interim solution for "forward looking" functionality before Load ICA is refined to look at forecasted load and planned projects. It is intended to provide customers with better guidance for siting loads before going through the application process. For example, a customer may view whether their project location is likely to have either "Expected Load Interconnection Capacity" or require grid upgrades for interconnecting new load. This is made possible by utilizing a combination of existing Load ICA data and other available datasets such as forecast feeder capacity, forecast bank capacity, planned load applications, planned projects. This data was added to the PG&E data portal

on December 6, 2023, and will be updated on a quarterly basis. PG&E is providing three “Expected Load Interconnection Capacity” attributes at the line section level to support customers while Load ICA improvements are being implemented.
    - PG&E’s proposed Load ICA use case: once ICA refinements are completed there is an opportunity for using load ICA data to streamline the early stages of the load energization process where capacity planners can assess all types of new business loads, including EVs. After the Intake phase is complete, Service Planning routes the application package to the Estimating (Design) team, who works with Distribution Planning to perform a review of the proposed load request and identify what equipment and/or modifications to the electric distribution system are required to safely serve the load request. If necessary, PG&E may need to study the load request further through a detailed study based upon the project size, location, and complexity for all types of customers during the Estimating phase. Projects can experience delays due to the high volume of work and the manual nature of the Distribution Planning review process. The new ICA use case is targeted to reduce processing time: to provide ready-to-use capacity information resulting in shorter processing cycle times. A pre-assessment phase can be offered for all types of service applications. PG&E is working with internal stakeholders to put together a scope and timeline of the project. The next step is to hold internal interviews and workshops to align on an implementation plan. The result of this will determine how existing processes and tools will be adapted to using the data, how the data will interface with capacity planners, and how the data will shape the customer experience.
    - PG&E’s DRP Data Portal is operational and accessible to the public, with GNA and DDOR data published annually, and ICA data published monthly.
- **The DRP Data Access Portal is undergoing a multi-year upgrade on both platform and functionality**
    - New Platform implementation to Esri ARCGIS configured by internal PG&E GIS COE to improve
        - Resource effectiveness
        - Cost efficiency
    - Updating DRP Compliance use case found in DRP DAP 1.0 with ongoing regulatory requirements
    - Adding Electric Vehicle Use Case (For Public and internal use)
    - Adding Flexibility for:
        - Added data,
        - New map layers
        - New Use Cases in the future
    - Automation of Data Flow – Facilitate data flow while lessoning business resource impact
    - Auto-failover for our clients
        - No need for Disaster Recovery or backup clients

        - Decreased downtime for our clients
    - Client Layers Flexibility to add client layers
        - Public Layer
        - Internal Layer and Redacted layer to be added as needed
    - Optimized Software & Hardware is ongoing and managed by Esri
        - No dependency on Infrastructure upgrades and purchases

- **Planning Tools Driven by DRP Compliance**
    - PG&E adopted LoadSEER 4 in 2023, which adds numerous capabilities to PG&E's forecasting process, including:
        - Transition from SCADA to AMI meter based historical load shapes
        - Weather normalization
        - 8760 load shapes
        - Scenario based analysis
        - Automated report generation
    - PG&E will use LoadSEER to create annual Capacity GNA and DDOR reports in 2024
    - The adoption of the CYME WebApp (described further in section "Distribution Planning Automation" below) enables the automated generation of the Line Section GNA report. PG&E will use this functionality for its Line Section GNA report in 2024.
- **CYME Substation Modeling and Analysis**
    - This project is in the planning stages. The focus of current development is on integrating existing systems, creating the ability to study multiple capacity planning scenarios and furthering automation of CYME analysis.
- **Distribution Time-Series Analysis Phase 2**
    - PG&E deployed CYME's Advanced Project Manager (APM) module in 2023, which has scenario-based modeling capabilities
    - PG&E is using the CYME APM, alongside CYME's Load Flow With Profiles (LWFP) feature, for the 2023-2024 distribution planning process.
    - LoadSEER 4's 8760 load shapes allow all hours to be modeled in CYME for time series analysis
    - PG&E is scoping and prioritizing further enhancements to these tools in 2024 and 2025 to support:
        - Time-series analysis of load management and non-wires solutions
        - Scenario-based technoeconomic solution identification
        - Regulator and capacitor optimization
        - Templatized and automated project proposal documents
    - PG&E's Distribution Planning team is working with the Integrated Grid Planning team to develop risk-based prioritization of capacity projects
- **Distribution Planning Automation**
    - PG&E deployed the Distribution Planning Automation project to production in 2023, including the following components:

        - CYME Webapp Forecast Integration Tool used to complete the capacity planning process that integrates multiple systems into a single application.
        - Incoming load database of new business applications for use across multiple platforms.
        - Project Database of distribution capacity projects and transfers to reduce modeling or importing into each planning study and automate reporting.
        - Portfolio Server database of distribution capacity projects and justification to reduce manual tracking.
    - The Forecast Integration Tool is being used by PG&E Distribution Engineers for the 2023-2024 Distribution Planning Process.
    - The Project Database will be used in 2024 for investment planning
    - The Webapp will be used to support automated GNA reporting in 2024
    - PG&E is scoping and prioritizing stabilization and usability enhancements for the Webapp in 2024

D. Grid Edge Computing & Applications

While the ADMS and DERMS technologies enable awareness, control, and grid coordination in a centralized system, for first party utility owned devices and third party DERs over the web, they do not scale effectively for millions of customer end points and do not have visibility to effectively manage the secondary network.

As an example:

1. For an electrified customer with a heat pump, electric vehicle, electric hot water heater, and a home battery; all four of these devices would have to coordinate across multiple centralized aggregators to perform even the most basic customer premise energy management. This incurs cost and complexities which can be difficult if not impossible to overcome utilizing centralized solutions.
2. For a grid constraint at a secondary transformer, there is no way to communicate a limit to a customer device with ADMS or DERMS, without deploying costly remote monitoring devices with associated telemetry. This would result in a need for 100's of thousands of transformer montiors to be able to gain basic visibility into the secondary network.

As a solution to these challenges, PG&E has begun exploring capability development for Grid Edge Computing which leverages the existing communications of the Advanced Meter Infrastructure (AMI) network with incremental upgrades to enable AMI 2.0 functionality.

Due to the nascent nature of AMI 2.0 technology, our approach is to first explore the capability utilizing EPIC funds before incorporating into the General Rate Case (GRC) or other funding sources. Our first meter application focuses on a high value challenge: Panel and service upgrades driven by vehicle electrification:

- **EPIC 4.02 – Socket of the Future & Residential EV Charging [Scoping phase, set to begin deployment in 2024 Q2]**

- Deployment of a cloud server which enables the AMI 2.0 platform capability, connected to our existing AMI network. This system allows for the provisioning of applications to AMI 2.0 meters, fleet management of applications, and associated functions of computing on the meters.
- Testing and configuration of our first AMI 2.0 application which seeks to enable a customer to avoid a panel, service wire, and service transformer upgrade by sending an active site limit in near real time.
    - Customer's Electric Vehicle Service Equipment (EVSE) connects wirelessly to an AMI 2.0 meter via local Wi-Fi connection using the Open Charge Point Protocol (OCPP) for signaling.
    - EVSE responds dynamically to the limit and defaults to a safe operating limit in the case of loss of communications.
    - Begun work with three EVSE partners, with plans to publish specifications more broadly for other EVSEs that meet the communication and program requirements to participate as well.
- Minimum Viable Product (MVP) approach which will support and fund up to 1,000 meters/chargers.
    - Deployment, testing, evaluation and improvement of the experience.
    - At conclusion of the project the AMI 2.0 platform remains useable for future AMI 2.0 application development/support, it becomes a permanent business system.
    - Support for the 1,000 customers after completion of the EPIC project, and any scale beyond, would need to be funded via the General Rate Case or other appropriate long term funding mechanisms (outside of EPIC).
- Out of scope at this time, but under consideration for further development either within this project or through other EPIC projects:
    - Offering EV submetered rates to the customer by leveraging the connection established between the smart meter and the EVSE.
    - "Add-on" electrification sub panels which manage smart breakers and coordinate with the smart meter to avoid panel and service upgrades using the same logic developed for the EVSE.

In parallel to the EPIC 4.02 deployment, PG&E will develop an AMI 2.0 roadmap which will include a capability scaling and application development/deployment strategy. This strategy would:

1. Develop our perspective on Grid Edge Computing, including when, where, and how the capability interacts with the other Grid Modernization technologies.
2. Leverage EPIC and other funding sources to develop, deploy, test, and scale individual applications that provide positive value to the system. Explore other types of applications beyond those listed in EPIC 4.02, such as:
    a. Wildfire mitigation
    b. Fault location, incipient fault detection, and asset health

c. Network model improvements such as detection of transformer phasing and/or service conductor sizing identification
d. Customer load disaggregation, energy management, and insights
e. DER enablement
f. Panel and service upgrade avoidance for other use cases beyond vehicle charging (e.g. solar and energy storage, V2G, etc.)

3. Coordinate with the 2027 General Rate Case (GRC), and will take an incremental scaling approach, rather than a full "rip and replace" of the electric AMI system.

III. Other relevant activities

In addition to the highlighted activities above, PG&E has been proactively making investments to modernize the grid in the face of climate change and has continued to develop customer programs to foster the adoption of DERS and electrify traditionally fossil fuel-based energy consumption such in transportation. Below are references more information about these initiatives:

- PG&E's Wildfire Mitigation Plan
- Demand Response
- Electric Vehicle Programs
- Community Microgrid Enablement Program (CMEP)
- PG&E's Electric Program Investment Charge (EPIC) Program for applied research & development and technology demonstration.

SDG&E GRID MODERNIZATION UPDATES

San Diego Gas & Electric Company

Grid Modernization Progress Report

April 19, 2024

Contents

Introduction

Over the past decades, San Diego Gas & Electric Company ("SDG&E" or "the Company") has made investments in innovative, cutting-edge technologies and programs that have made it a leader in utility wildfire safety and grid resiliency. From integrating automation and control technologies, to implementing efficient work processes, to designing and building microgrids, our investments are already benefiting our customers and serve as a foundation for the grid of the future.

SDG&E and its customers are also no strangers when it comes to integrating distributed energy resource ("DER") technologies. To date, SDG&E has authorized over 317,000 DER interconnection requests, installed at a rate of over 2,000 each month. These DER installations represent approximately one in every five households in SDG&E's service territory, with over 2,185 megawatts ("MW") in aggregate nameplate capacity.

SDG&E believes that the future grid needs to be dynamic, robust, and resilient, and it must evolve to support continued DER proliferation and enhancements to safety and reliability through assimilation of other emerging technology. The future grid also needs to empower customers, increase renewable generation, integrate electric vehicles ("EV"), and reduce greenhouse gas ("GHG") emissions while simultaneously maintaining and improving system safety, reliability, operational efficiency, security, and customer privacy. Thus, SDG&E's grid modernization vision is to innovate and optimize a grid that is safe and reliable and accelerates decarbonization – all while delivering value and choice for all customers. This vision reinforces SDG&E as the operator, planner, and integrator for the distribution system, while being supportive of state goals regarding DER adoption, transportation electrification, and decarbonization.

The following report details SDG&E's advancements, challenges, and future outlooks in the grid modernization areas of grid management systems, communications and cybersecurity infrastructure, and engineering software and planning tools.

Grid Management Systems

Integrated Test Facility ("ITF") Expansion

The ITF provides a learning and testing space for SDG&E to develop its own institutional knowledge and intellectual capital that aligns with CPUC goals and objectives. It is a vital asset that provides internal engineers and experts opportunities to work side by side. This resource provides a true cross-functional effort, designed to help projects from different groups and departments at SDG&E to coordinate and integrate, thereby increasing SDG&E's knowledge of power system and advanced technologies. Each laboratory room compliments efforts to improve the electrical power systems' reliability and efficiency. By testing within a laboratory environment, it allows SDG&E to safely test and troubleshoot different technologies, techniques and scenarios without putting SDG&E's personnel and operational systems at risk. The ITF is an integral part of SDG&E's safety culture.

Recent Activity, Challenges, and Outlook
Since 2021, the ITF has installed a smart board and Audio and Visual upgrades to the conference rooms. In addition, the ITF Team purchased software licenses and support for Real Time Digital Simulators that help model and test the technologies of the future within a lab setting. The ITF is

being utilized for projects that are being tested for wildfire prevention, system protection, reliability, and renewable communications. There have been successful outcomes of ITF projects. To name a few, SDG&E engineers pioneered and patented a falling conductor protection scheme in the event the power line breaks. This system can de-energize the line before it lands on the ground. This project was designed, developed, and tested in the lab to tell the electric system to immediately shut off power on a line if sensors detect that it is broken. There is also the development of servers using IEEE 2030.5 Protocol in the lab to test inverter communications for renewable energy resources, to enhance operational flexibility. SDG&E has also designed and tested our own 4G LTE communications system, to replace legacy systems and enable technologies such as Falling Conductor Protection to work quickly and reliably. SDG&E is also using the ITF to test behind the meter isolation switches that could help customers stay energized during utility outages. The CPUC has requested this effort be done by the three IOUs in California and the ITF is where SDG&E performs its testing.

The current challenges are the ability to collaborate with academia and third-party entrepreneurs within the bounds of prudent utility business practices. While SDG&E sees a potential value with working with outside parties in the ITF, there are safety and regulatory accounting concerns that make it infeasible.

SDG&E plans to double the size of the ITF laboratory space in the near future. As the grid handles more complicated technologies, there is a growing need to test the communications and connections of tomorrow in the safe environment the ITF lab provides.

Advanced Distribution Management System (“ADMS”)

SDG&E’s initial ADMS included an Outage Management System (“OMS”) integrated with a Distribution Management System (“DMS”). To achieve SDG&E’s desired operational vision, the ADMS was tightly integrated with other ancillary operational systems including the Geographic Information System (“GIS”), SCADA, Customer Information System (“CIS”), and Advanced metering infrastructure (AMI) systems. This initial ADMS deployment included a fully as-switched model of the distribution system which provides granular system visibility and management capabilities for the operators. The OMS also enabled the full suite of digital switch plan management, including documentation, tagging, and authorization capabilities across emergency and planned work, with all SCADA switching executed remotely from the control center. The full ADMS platform also enables timely customer outage communications, integrated workflow management and real-time resource status management both integrating data from AMI and SCADA with the internal as-switched grid model. ADMS has been a core enabling factor when it comes to SDG&E’s superior safety and reliability metrices.

Moreover, ADMS is a key foundational system that anchors SDG&E’s ability to operate and manage the distribution system in a high DER future. Its DER-aware modeling, integrated network analysis and system reconfiguration applications paves the way for SDG&E to develop its growing capabilities around DER management and is a first step towards the fully integrated ADMS and DER Management System (“DERMS”) platform.

In its TY 2024 General Rate Case (“GRC”), SDG&E proposes the Reliability and Operational Safety (“ROSE”) project and Smart Grid Operation (“SGO”) projects to ensure ADMS can be enhanced to address safety and reliability driven needs. These enhancements also provide a foundation for implementation of broader DER management capabilities, as proposed in the new Enterprise DERMS project. The scope of ROSE and SGO projects include enhanced customer communications during blue sky and Public Safety Power Shutoff (“PSPS”) events, expanded visibility to DERs and advanced outage and reliability analytics. Additionally, SDG&E intends to improve its electric modeling, which is the foundation for all optimization applications within the ADMS. Accurate modeling not only improves switching accuracy and operating efficiency, but also provides an accurate baseline for planning and operating with DERs in the distribution system. The projects will also build upon existing architecture and platforms and further implement and refine advanced applications such as Volt/Var Optimization ("VVO"), Fault Isolation and Service Restoration ("FLISR"), Fault Location ("FL") and day ahead forecasting. Both the ROSE project and the SGO project are driven primarily by safety and reliability, but also provide a meaningful foundation for supporting DER integration.

Recent Activity, Challenges, and Outlook
In the recent past, SDGE's ADMS teams have been focused on improving integrations with systems such as the new CIS system, providing better more timely outage notices and communications with individual customers. Many enhancements have been made to automate Distribution Operator functions, thus reducing workload, and improving Operator focus on safety. Other improvements to the IT infrastructure have created a more resilient and available ADMS system -- even during cybersecurity patching, planned system maintenance and disaster recovery -- thus also improving safety considerations.

Distribution model optimizations have been completed to enable more accurate prediction and management of circuits during planned and unplanned outages in preparation for DERMS. DER assets modeled in the ADMS were verified to improve power flow calculations and direction. To further increase the visibility of DERs, large scale DER assets (rated at 1MW and greater) require SCADA telemetry and the future roadmap includes leveraging this data to improve the ADMS model and forecasting accuracy. Currently this data is viewable to the operators, and SDG&E has a methodical approach to continue to add in real-time data to the ADMS model.

SDG&E regularly upgrades key systems including the Network Management Systems (NMS) and Oracle Utilities Analytics (OUA), to newer versions to enhance safety and reliability through improvements in both processes and technology. In conjunction with the system upgrades, SDG&E added enhancement tools including FLISR and Suggested Switching. These are under evaluation alongside day-ahead forecasting in 2024. Legacy applications were replaced by web-based IT supported solutions to quickly gather and report data needed. SDG&E has added indices to track customer experience to help improve identification of reliability improvements to prioritize.

A primary challenge to most ADMS systems is the rapid pace of change in smart grid device technology and incorporating those improvements into the SCADA and ADMS systems. In addition, the proliferation of DER devices, their emerging standards and the onboarding and integration of those devices onto the distribution grid have caused an influx of changing requirements that ADMS must support. While the ADMS distribution system model is updated with additional SCADA data and DER attributes, improving the accuracy of FLISR and FL solutions -- in addition to expanding these capabilities to other circuits --becomes more challenging. As a result, FLISR is currently set to manual mode to evaluate the potential solutions and make improvements to the algorithm and power flow. FL solutions are also closely monitored and evaluated to identify and correct model inaccuracies. Finally, as Distribution Operations responsibilities grow, the need to automate repetitive tasks and provide plans and actions that reduce Operator workload to manage the distribution grid more safely, will continue to challenge the ADMS.

SDG&E's ADMS will continue to include enhancements that incorporate new technologies that are focused on improving reliability, furthering automation, and setting the stage to add enhancements for DERMS. In 2023, the ADMS was updated to include capabilities that use the

Fire Potential Index (FPI) generated by the SDG&E Meteorology team to raise Distribution Operations and crew personnel awareness of the potential for wildfires and allow for greater controls to ensure safe operations in times of greater wildfire risk. Also, in areas of high FPI, a switch plan for minimizing customer outages will be automatically generated so that should a PSPS event be necessary, Distribution Operations personnel will be able to act more quickly. ADMS will also be reintroducing mobile application access to ADMS to provide field personnel and crews real-time access to ADMS data to increase field crew awareness during both planned and unplanned work, develop more accurate estimated restoration times during outages and provide quicker and more accurate damage assessments to be submitted from the field. SDG&E has been developing pilots and procedures for these applications since 2023. Finally, as part of modeling improvements, ADMS will also be expanding the use of FLISR to additional circuits to automate the detection and restoration of unplanned outages by enabling FLISR on additional circuits. To support the upcoming DERMS system, additional SCADA data will be acquired from the SCADA head-end system to more accurately identify the DER devices, ratings, and attributes so that SDG&E can accurately forecast and signal the need for dispatchable DER that we expect to interconnect in the future.

Local Area Distribution Controller ("LADC") – Microgrid Controller

To support the controls associated with microgrids, SDG&E is working on developing and deploying a new microgrid controller, known as the LADC. The LADC is designed as a fast local controller that can rapidly control inverter-based resources and distributed generation while leveraging synchro-phasor data as control input. This fast control was deemed necessary based on experiences dealing with transient microgrid operating conditions in a low inertia environment. This is especially true for uncontrolled customer DER with legacy inverters without strong ride through capabilities where voltage or frequency excursions associated with these transients can cause them to trip offline en masse. SDG&E expects to integrate all resources, including those operated by third parties within multi-premise microgrids, with the LADC in addition to utility assets. The LADC projects are primarily driven by DER Integration but are also necessary to ensure safe and reliable operation within microgrids connected to SDG&E's distribution system.

Utilizing the LADC and to increase visibility, management, and control of the distribution system, SDG&E has also been utilizing a combination of data, analytical method, engineering and operations knowledge, and various tools to build a data notification system and visualization dashboards. This enables timely and targeted response to data changes and system events. Some of the use cases implemented include voltage monitoring and notification, phase balancing, and overloading circuits watchlist. With more data available, including DER performance data, SDG&E expects to continue using analytics to further finetune its process to make more data-driven planning and operational decisions. In addition, SDG&E has ongoing grid technology deployment such as the Advanced Protection ("AP") technology to further extend branch circuit protection for improved reliability.

Recent Activity, Challenges, and Outlook

In the past 6 months SDG&E teams have been advancing LADCs at the Cameron Corners Wildfire Mitigation Plan (WMP) Microgrid, the Ramona Air Attack Base WMP Microgrid and the Borrego Springs Microgrid; overcoming technical issues inherent with mixed-maturity energy storage devices from different manufacturers. In December 2022, the teams completed two milestones, integrating both LADC and SCADA controls at the Ramona Air Attack Base WMP Microgrid. This milestone enabled SDG&E's Distribution Operations to have control of the Tesla Megapack Battery for use during Wildfire or PSPS events. In December 2023, Phase 1 LADC integration completed at the Borrego Springs Microgrid, but full automation was postponed until LADC Phase 2, due to mechanical failure of the two diesel generators. In the first quarter of 2024, engineering teams have completed LADC Factory Acceptance Testing and User Acceptance Testing for Elliot Microgrid using SDG&E's ITF Power systems Lab. Currently the SDG&E teams are performing Elliot Energy Storage Microgrid Controls Acceptance Testing at SDG&E's ITF Lab, and configuring Paradise Energy Storage Servers for Factory Acceptance Testing. Concurrently, the teams are supporting priority operational work, supporting Cameron Corners WMP Microgrid Flow Battery installation, supporting installation of new Tesla Megapacks, and supporting the Deisel Generator replacement at the Borrego Springs Microgrid.

The project teams have faced significant challenges from many angles. Most significantly for Borrego Springs was aging assets and for delay of the Cameron Corners flow battery. Additional challenges have come because each piece of microgrid hardware is programmed with custom logic and, although subsets of hardware are being tested in lab environments prior to field installation, full system lab tests are not possible; the entire system is operated for the first time in production environments with customers on the circuits.

In the next two years, the project teams will leverage the lessons learned and operational techniques developed while integrating the LADC at the Ramona Air Attack Base WMP Microgrid and Borrego Springs Microgrids. In 2024, SDG&E is working towards LADC integration for Elliot, Paradise, Boulevard, and Clairemont Microgrid sites, which are all Phase 2 LADC sites. The 2024 roadmap for LADC integration will be more productive because these four microgrids use the same technology and vendors. The teams expect Shelter Valley WMP Microgrid, Butterfield Ranch WMP Microgrid, Cameron Corners and Borrego Springs New energy asset construction to complete and become operational in early 2025 so LADC integrations for these sites are on the roadmap for 2025. Although the architecture and integrations are complex, the LADC puts SDG&E's Distribution Operations, Distributed Energy Resources, and Generation Operations teams in control of microgrid assets with their respective native control systems.

Enterprise DERMS

SDG&E views DERMS as providing the overarching capabilities within the operational domain to monitor, manage, and optimize DERs. With the already solid foundation established by previous investments in SCADA Headend replacement, ADMS, and other network infrastructure, SDG&E believes it is important to carefully evaluate and design the capabilities needed to further enable DER integration in the operational domain and its existing systems portfolio. Instead of building out one enterprise application platform, SDG&E believes it can enhance its existing tools and build out scenario-driven capabilities as needed in a progressive manner.

Although SDG&E has not implemented an enterprise DERMS to date, it is one of the early adopters in expanding its grid management capabilities to embrace DER integration. SDG&E has a long history of working with national labs, vendors, research facilities, and universities via the avenue of state directed EPIC, Department of Energy Solar Energy and Technologies (SETO) Funding Opportunity Announcements, and other grant opportunities. However, additional capabilities and functionalities, along with consistent use cases, are needed to develop and implement DERMS at the production level. SDG&E envisions DERMS to perform functions in the following three categories:

Day Ahead: The DERMS will consider the day ahead load forecast and anticipated equipment configurations and settings on a circuit-by-circuit basis, which it will leverage from the ADMS. The ADMS forecast is sophisticated and leverages weather forecasts, static (non-dispatchable/controllable) nameplate solar, smart meter data, SCADA telemetry points, as well as the circuit and equipment impedance models to determine the projected load at various telemetry points on a 24-hour schedule. If a constraint is detected by the day ahead simulation, the DERMS will signal the need for dispatchable DER to come online the next day. This signal will be based on an optimization routine that considers the number and capabilities of DERs, circuit constraints such as voltage/thermal capacity, economic constraints), repetitive-use constraints such as not overusing demand response resources, and any other constraints that may come up depending on the type of use. For specific types of DER, like battery storage, DERMS could signal day ahead charging limits based on far more up-to-date forecasts, rather than the conservative annual forecast used today for our distribution-connected battery storage customers who are participating in the wholesale market. In 2023, SDG&E focused on the Distribution Management System (DMS) model updates and developed procedures to improve model accuracy and convergence, resulting in the ability to run day-ahead forecasts and estimate peak loads for subsequent days. In 2024 we have begun accuracy comparisons in preparation for a DERMS to ingest this data.

Real Time: SDG&E also expects the DERMS, which will be connected and integrated with SDG&E's as- switched distribution system model on ADMS, to react in real time if set electrical constraint values are exceeded to prevent voltage and overload problems that could lead to outages on the distribution system if not mitigated. The goal is for these constraints to be dynamically captured such that the DERMS has the capability of recognizing the actual constraints on the as-switched electric system. As an operator performs switching to restore service to customers, the DERMS can then evaluate the large DERs on the system and adjust their output, either up or down, depending on the scenario. These output adjustments will provide grid performance that stays within the system constraints that are recalculated as the system is reconfigured through switching operations. Key to this is the integration SDGE has built with our Enterprise GIS system. System changes are digitized and uploaded to our NMS on a daily basis and this year SDG&E continues to identify solutions that clean up data discrepancies.

Record and learn: The DERMS will need the capability of verifying the expected output from dispatchable resources and validating the actual output by measuring what the distribution system received in response to the dispatch signals sent to the resource. Event reporting will be necessary for determining if contract obligations are met. Event reporting can also act as a data feedback loop to improve the accuracy of day ahead forecasts and to improve the optimization programming of the DERMS. To date, SDG&E receives telemetry from all WDATs greater than 1MW. This data is brought into the control center for operator visibility and to inform decision making in switching on this distribution system. Additionally, static charge limits are viewable in the control center which give conservative predictability to the devices on our system.

Recent Activity, Challenges, and Outlook

SDG&E met with additional potential DERMS vendors to have them introduce and provide demonstrations of their product, and to allow SDG&E to ask technical questions regarding the capabilities of their product. Additionally, SDG&E representatives have participated in industry conferences and sessions to knowledge share on DERMS roadmap and specifications pertinent to brining on a DERMs vendor. We are working to better define our use cases and refine our vendor list for a formal Request for Proposal. SDG&E also established a 2030.5 server in its Technology lab to start demonstrating the capability of communicating to inverters and controlling inverter outputs, a key capability the DERMS will need to monitor and manage DERs. In SDG&E's current system, large DER assets participating in the wholesale market are interconnected with SCADA switches at the point of interconnection which provides telemetry and control. However, the control is static, SCADA can either isolate the customer or DER from the grid, or it can connect the customer or DER to the grid. The development of the 2030.5 technology would allow SDG&E and its future DERMS to control the inverter output providing a more sophisticated solution that is more friendly to both the customer and the electric system. Generation/load output values can be adjusted rather than completely isolating DER assets from the system.

As mentioned above, to have the DERMS SDG&E envisions, it will need to have the capability to control either directly or through real time request to customers at the inverter level vs at the SCADA level,[1] and SDG&E is still early in its development of the 2030.5 head end system. In addition, the DERMS system will rely heavily on day ahead forecasting to optimize dispatchable DER at scale, and SDG&E must work to refine its data inputs into the distribution system model to continue to improve the accuracy of its day ahead forecasts. The ADMS model enhancements continue to be SDG&E's focus before our DERMS implementation.

The LADC deployments detailed above alongside pilot projects, including vehicle to grid and virtual power plants, provide us with additional experience and use case understanding necessary capabilities as we move toward a DERMS solution.

SDG&E plans to submit a formal request for proposal to DERMS vendors in 2024 and is on track to purchase and integrate a DERMS system in 2025, with the goal of piloting the use cases described in future years consistent with SDG&E's current GRC application.

Supervisory Control and Data Acquisition ("SCADA") Headend Replacement

SDG&E has long been using the SCADA system to monitor, control, and protect distribution assets. As the cornerstone of its operational platform, the implementation of the distribution SCADA ("DSCADA") system more than two decades ago initiated SDG&E's roadmap establishing system management capabilities within the distribution control center. Over time, this legacy DSCADA system faced increasing challenges as more and more communication edge devices were deployed in the field.

In 2017, SDG&E engaged a consulting firm to perform a full evaluation of the DSCADA system. Upon evaluation, it was identified that the legacy DSCADA system did not meet SDG&E's technical roadmap requirements for grid modernization. Key issues included a lack of support for Internet Protocol ("IP") communications as well as a limited capacity to send/receive DSCADA points associated with newer devices and general system scalability concerns. Moreover, given the DSCADA system was deployed more than 20 years ago with antiquated user interfaces, the development of DSCADA screens were very inefficient and time consuming. The system did not have a reliable backup process and was heavily dependent on an aging hardware configuration, which created many challenges for operational support of the system.

Consistent with the final recommendation by the consulting firm, SDG&E decided to replace the legacy system with a new DSCADA Head-end system. In 2020 SDG&E completed a full upgrade of DSCADA. The upgrade enabled the DSCADA system to continue serving as the critical data aggregation system to integrate additional grid sensing, switching and protection equipment for the control center. In 2022 and 2023, SDG&E completed the Phase 2 of SCADA Head-end upgrade project to further enhance the DSCADA system to have full testing capabilities.

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[1] For some Behind-The-Meter (BTM) applications such control will require the presence of a Power Control System (PCS) that monitors power flow at the customer's Point of Common Coupling (PCC) with the utility and uses this data to signal the inverter to increase or decrease output as necessary to manage grid imports or exports to specified levels. A PCS will be necessary because control of the inverter by itself has no effect on the customer's end-use load.

Recent Activity, Challenges, and Outlook

Upgrading the SCADA system to newer versions enhances safety and reliability through improvements in both processes and technology. In conjunction with the system upgrades, SDG&E teams have successfully converted serial SCADA communications to an IP based communication protocol improving SCADA reliability. In addition, Security Profiler software was implemented to establish baselines and monitor deviations of software on the SCADA equipment within the SCADA network which hardened the cyber security posture. The SCADA team has successfully integrated to LADC and Falling Conductor Protocol controllers. The team transitioned from quarterly system security patching to monthly with no interruptions to operations. Scheduled nightly server backups of all non-production and production environments which are stored for six weeks improving business continuity. The number of active RTUs in the SCADA has increased by 15% in the last two years. Additionally, in 2022 SDG&E added a physical multi- factor authentication to critical areas where SCADA equipment is located. The team implemented the use of a new change management software that will monitor and record system changes for auditing purposes. Necessary segmentation of server processes will increase stability for integrations with NMS and provide SCADA data to SDG&E's corporate historian.

A primary challenge to SCADA systems is maintaining cyber security of the network in the current threat landscape. This requires constant monitoring and improvements to enhance system security. The implementation of automated security patch software would allow for better efficiency and consistency across SCADA hardware. Consistent upgrades to the operating systems and hardware will be needed to maintain business continuity and system security. Additional challenges include the need for a more advanced reporting and analytics application to fully utilize historical data to improve situational awareness. As the Distribution SCADA system continues to grow, the need increases for additional licensing and the migration of SCADA communications to SDG&E private Long-Term Evolution (LTE) network to improve visibility and reliability of the system.

In 2023, Inter Control Center Protocol (ICCP) was implemented, non-production and will be implemented in production in 2024, allowing for improved situational awareness and data sharing with other business applications. The team will implement the use of a new change management software that will monitor and record system changes for auditing purposes. Fully operational SCADA simulators will provide a necessary training tool for Distribution System Operators that will be integrated with the Oracle Network Management System (NMS) System. A new SCADA test environment will be integrated with Oracle NMS to improve testing between the critical system applications. Necessary segmentation of server processes will increase stability for integrations with Oracle NMS and provide SCADA data to SDG&E's corporate historian. The addition of a redundant non-production development environment allows business continuity in the event of a system emergency where system updates can be performed in an isolated environment and validated before implementation to the production SCADA in line with SDG&E's Operational Technology Standards. SDG&E is preparing for additional hardware and software upgrades in 2025. Efforts will include improvements to the integrations with the company's corporate historian, modifications for more intuitive SCADA alarming for the distribution control center, and continually enhancing the cybersecurity footprint.

Demand Response Management System ("DRMS") Replacement

SDG&E has over two decades of experience in managing Demand Response ("DR") programs. The DRMS replacement project was targeted to implement a new DRMS system that meets the current and future needs of Demand Response ("DR") customers and the resulting DR programs. This platform allows SDG&E's internal DR team to track and manage the various DR Programs and Pilots via one single platform. The DRMS replacement system is designed to be able to grow and expand, allowing SDG&E to have the capacity to manage and signal smart devices. The new platform allows SDG&E's

DR team to provide a better customer experience as many more customers purchase smart devices and equipment that will be used to provide DR. The DRMS technology is primarily driven by DER integration, but the replacement project was primarily driven by aging IT infrastructure.

Recent Activity, Challenges, and Outlook
The new DRMS platform allowed SDG&E to retire these old legacy systems and look to the future. The new SDG&E DRMS system went live on March 28, 2023, and has been consistently updated to include more DR programs.

A significant benefit of the new DRMS platform is that all SDG&E DR programs and Pilots are now under one application. A single application provides scalability and adaptability that will accommodate new DR pathways and capacity, thereby enabling DR to grow for many years.

The role and types of DR programs are changing as we focus more on grid resiliency and reliability. The new DRMS system will allow the management of our existing DR programs and Pilots, our third-party programs and integration of these programs with the CAISO wholesale market. It will be expandable and therefore allow SDG&E to effectively manage future DR programs. These future DR programs will include commercial and residential devices, energy management systems along with battery storage, and electric vehicle to grid applications. The new DRMS system will also improve our third party and customer experience as we move to a more dynamic landscape of dynamic pricing, resiliency and demand flexibility.

Communications and Cybersecurity Infrastructure

Fiber Development
SDG&E's current backhaul fiber optic network is comprised of over 900 miles of fiber connecting over 75 transmission substations. SDG&E is approximately 60% complete with another 590 miles to build towards completing a diverse fiber optic infrastructure network to all remaining substations. The fiber optic network not only provides a direct connection to substation equipment, but it also serves as backhaul and redundant pathways for Long-Term Evolution ("LTE") field area network technology and Microwave links that enables distribution automation devices to be interconnected to back-end control systems. In the 2024 GRC, SDG&E is continuing with the building fiber network through the Fiber Optic for Relay Protection & Telecommunications project, and the HFTD Transmission Fiber Optics project. Both projects are primarily driven by safety and reliability but provide the network foundation for supporting DER integration.

Recent Activity, Challenges, and Outlook
By the end of 2023, SDG&E installed 303-miles which of fiber. In 2023, SDG&E installed 29.7-miles which connected 12 Transmission substations. In 2024, SDG&E is scheduled to construct an additional 26-miles which connects 8 Transmission substations.

The two main challenges that impact project delivery are Agency permitting delays and material lead times that vary widely.

SDG&E has increased support for the Fiber Build Infrastructure projects. With the construction of an estimated 30+ miles per year, the long-term goal is to build a complete and diverse fiber network infrastructure by 2032.

Private LTE

SDG&E is deploying a privately-owned LTE field area network using licensed radio frequency ("RF") spectrum by means of the Distribution Communications Reliability Improvements ("DCRI") program. The private LTE ("PLTE") network and associated upgraded communication infrastructure will enhance the overall reliability of SDG&E's communication network, which is critical for enabling fire prevention and public safety programs. In the meantime, SDG&E envisions this network will also serve as a foundational network for DER integration efforts. Similar to the Fiber development projects, the private LTE Project is also primarily driven by safety and reliability but provides the foundation for supporting DER integration. The project is an ongoing program and is expected to continue through 2030.

Recent Activity, Challenges, and Outlook
The PLTE deployment is underway with 58 sites built and more slated for 2024. The acquisition of the PLTE Spectrum has been completed for San Diego and Imperial counties. Migration of existing sites, end uses, and system protection technologies have begun with a target of approximately 800 being converted in 2024.

SDG&E expects to ramp up in the coming years the actual number of sites that are installed per year.

Most sites planned for base station installation have engineered steel foundation piles that will have telecommunication antennas at the top of the pole and electric (12 kV and below) attachments in the middle of the pole. Poles are currently undergoing standardization. Development of pole specification, including workspace, operational, and manufacturing requirements, has taken longer than expected. To complete the pole standardization, three pilot sites were selected and pole orders were placed at the end of 2023. In 2024, construction of these three pilot sites and standardization of pole designs is expected to be completed, which will accelerate the program in 2025 and beyond. In addition, process improvements with substation and transmission facility engineering and operations groups are being developed to ensure proper design and construction and streamline the activities to help accelerate the program.

SDG&E projects completion of the PLTE project with full coverage of our service territory by 2030.

Cyber Security
SDG&E has established holistic Operational Technology ("OT") and Information Technology ("IT") and cloud cyber security strategies to mitigate cyber risks and protect its systems and customers from cyber- attacks and potential catastrophic events. These integrated efforts are ongoing and continue to evolve as requirements, standards, policies, and threats change. Our OT cybersecurity program has quickly grown into a function utilizing technology and standards to enhance engagement across the business, expand asset visibility and enable enhanced vulnerability management capabilities. We have invested in measures to strengthen perimeter and internal defenses and have adopted use of modern technologies across various core cyber infrastructure capabilities. SDG&E will continuously assess associated cyber risks and evaluate new technology that can be adopted to mitigate these risks. SDG&E also plans to continue to actively engage in state initiatives working with broader stakeholders.

SDG&E will continue to support broader business objectives and adoption of modern grid, cloud, OT and IT systems and infrastructures by evolving security controls, utilizing, and conforming to NIST standards, and continuously assessing internal and external threats. In partnership with various business entities, SDG&E continues to develop a culture of cyber awareness and vigilance, ensuring our staff and contractors are informed on top security risks such as social engineering, phishing, and other related threat actor tactics.

SDG&E relies on Federal, State, and Local government partnerships for intelligence feeds along with peer utility industry relationships and private (subscription) based services for Industrial Control Systems (ICS) cybersecurity threat intelligence. We also obtain cybersecurity threat intelligence from a variety of entities and sources, including Information Sharing and Analysis Centers (ISACs), the Federal Bureau of Investigations (FBI), FERC, the DOE, the Department of Homeland Security (DHS), CISA, Transportation Security Administration (TSA) and a variety of US intelligence community agencies. Information from threat intelligence sources in the utility industry continues to reveal adversaries that are using advanced tradecraft in their attempts to access our nation's utility systems.

The Cybersecurity program utilizes risk management frameworks, including but not limited to the National Institute of Standards and Technology (NIST) Cybersecurity Framework, Center for Internet Security (CIS-20), NIST 800-53, and MITRE ATT&CK framework. Additionally, SDG&E complies with all applicable laws and regulations both at the State and Federal level.

Engineering Software and Planning Tools

Customer Facing Portals

To improve customer experience and support customers' energy transition interests, SDG&E has rolled out customer facing portals such as the Distribution Interconnection Information System ("DIIS") and Distribution Resource Planning("DRP") Data Portal, which have provided greater ease and flexibility to customers adopting DER technologies. A new Microgrid Portal was recently developed for local and tribal governments to support community resiliency planning. A description of the portals, recent updates and future lookout are included below.

DRP Data Portal
In Rulemaking 14-0808-13, issued on February 2015, the CPUC required SDG&E and other utilities to publish a DRP Data Portal. The portal is comprised of an Integration Capacity Analysis (ICA) map which includes information from SDG&E's annual Grids Needs Assessment (GNA) report, and Distribution Deferral Opportunity Report (DDOR), among other data types. The ICA maps published within the portal contain data from both the Generation ICA and the Load ICA. The data presented in the ICA map provides the estimated feeder level integration capacity results at a section level or node level. The Data Portal also hosts a data layer to allow registered customers to download SDG&E's GNA and DDOR reports.

Recent Activity, Challenges, and Outlook
Since 2021, in accordance with Administrative Law Judge's September 9, 2021, Ruling Ordering Refinements to the Load ICA, SDG&E has been working on implementation of several modeling changes to Load ICA. SDG&E made progress on the development of the modeling changes and intends to complete these changes by the first quarter of 2025. The data portal is also currently in the scope of the High DER Grid Planning OIR (R.21-06-017); additional changes may be identified and proposed as appropriate.

Interconnection Portal
In 2013, SDG&E launched an automated application process and online tool, DIIS for contractors and customers to manage interconnection projects. DIIS is a self-service portal which enables customers and contractors to fully manage the lifecycle of NEM projects. The tool allows users to create projects, receive real time status updates and notifications, and is available 24/7. As

mentioned in the overview, SDG&E's DIIS has greatly facilitated its customers embracing DER adoption quickly and easily. To date, SDG&E has authorized over 317,000 DER interconnection requests advancing over 2,185 MW of generation. Moreover, DIIS allows fast track applications to be processed in an average of 3 days for residential applications.

Recent Activity, Challenges, and Outlook
Since 2021, SDG&E has been working on further DIIS reporting functionality to support Rule 21 for CPUC reporting and auditing requirements. New features are being designed and deployed to intake Wholesale Distribution Access Tariff (WDAT) customer applications, provide new project management features to better track design, construction, and interconnection activities, in addition to dissemination of generation customer information to distribution operators to support distribution grid operations while supporting wholesale market participation. As of March 2024, SDG&E is nearing the first phase of releases for the DIIS upgrades related to the WDAT and tracking (scheduled for Q2 – Q3 of 2024).

Microgrid Portal (Tribal/Local Government Portal)
SDG&E completed development, in November 2023, of a separate, access-restricted data portal for local and tribal governments. The development and activation of the portal complies with requirements specified in the CPUC Decision 20-06-017.[2] This portal supports local and tribal efforts to promote community resiliency.
community resiliency.

The portal includes a map application that displays GIS data. The GIS data depicts (a) planned grid investments, (b) high fire threat districts, (c) electrical infrastructure and (d) weather-related factors that led to the decision to de-energize from each prior PSPS events and the resulting distribution and transmission line outages.

Planning Tools

In the past decade, SDG&E has implemented many updates to its planning tools to meet the deliverables identified in the multiple tracks of the Distribution Resources Plan (DRP) proceeding. These tracks required creation of new analyses such as ICA for both generation and load and DER Growth Scenario forecast processes. The scale of the data and analysis requires specific and customized tools to process and promote data quality and accuracy. As discussed earlier, the ICA tool is housed within the DRP data portal. Information in the DRP data portal is intended to provide information that informs customers' efforts to interconnect new generation and to add load. ICA takes input from GIS, SCADA and AMI and is intertwined with existing planning tools such as Synergi and LoadSEER.

In 2015, SDG&E adopted a third-party proprietary software forecast toolset, LoadSEER, from Integral Analytics, Inc., to disaggregate the CEC's system-level forecast of loads and Behind-The-Meter (BTM) DER additions to the circuit level. This tool provides SDG&E a geospatial load disaggregation methodology and allows integration of DER forecasts required through the DRP DER Growth Scenarios. The enhanced forecast capability helps determine the timing and duration of future forecast distribution capacity needs. In 2020, SDG&E created a tool that queries the coincident contribution of DER resource impacts during each circuit's/bus's forecast peak time to better inform the "indirect distribution cost" utilized in the IDER Avoided Cost Calculator (ACC) proceeding. SDG&E currently uses a variety of methodologies, tools, and software including Synergi and LoadSEER, to perform the analyses necessary to accurately identify the planned infrastructure improvements that will prepare the distribution system for high electrification.

Recent Activity, Challenges, and Outlook
As discussed above in the DRP Data Portal section, since 2021, SDG&E has been working on implementation of several modeling changes to Load ICA. SDG&E has also been working on continuous improvement of analytical accuracy for both Load ICA and Gen ICA. Further, the changes to Load ICA are driving and will continue to drive several changes to SDG&E's distribution system modeling and analysis software, Synergi, including but not limited to software updates.

Conclusion

The projects and programs that SDG&E has implemented under grid modernization support SDG&E's grid modernization vision and align with the state goals regarding DER adoption, transportation electrification, and decarbonization. As California continues to electrify, SDG&E understands the importance and value of DERs in meeting the significantly increased electric demand electrification will bring. At the same time, an increasing number of DERs add operational complexity. The tools and processes described in this Grid Modernization Report will allow SDG&E to continue to provide safe and reliable distribution service. The investments SDG&E is making today in its grid management tools, cybersecurity and communication, and engineering and planning tools will allow SDG&E to have fewer limits on distribution circuit hosting capacity, more dynamic charging limits for battery storage customers, and more nuanced DER management under abnormal configurations due to advancements in inverter control. All these enhancements allow for the safe and reliable integration of more DER of all varieties onto the electric system, supporting electrification and the high DER future.

SCE GRID MODERNIZATION UPDATES

SOUTHERN CALIFORNIA EDISON COMPANY

Grid Modernization Progress Report

March 15, 2024

Executive Summary

Southern California Edison Company's (SCE's) vision is to transform its distribution grid into a secure, flexible, networked platform that adapts to changing needs driven by higher customer distributed energy resource (DER) adoption, optimizes DER value through advanced grid management, supports customer electrification needs, and ensures grid reliability and resiliency in the face of climate change. This vision requires the continued investment in five categories of technologies and functional capabilities: (1) Engineering and Planning (E&P) Software Tools, (2) Grid Management System (GMS), (3) Communications and Cybersecurity, (4) Automation, and (5) DER Hosting Capacity Reinforcement. SCE made substantial progress across these five areas between 2021 and 2023, and this report highlights the accomplishments, use cases, benefits, and challenges for the first three areas (E&P Software Tools, GMS, and Communications and Cybersecurity).

As capabilities are deployed, the GMS will work in concert with field devices to provide customers with a safe, reliable, and resilient grid that powers our customers' clean energy choices. The GMS will also help increase DER hosting capacity through its load and DER management capabilities. SCE's modern communications systems are replacing SCE's legacy technology with low latency, high bandwidth, secure communications to support modern grid capabilities. Over the next few years, SCE will continue to enhance the E&P Software Tools to continue advancing our system planning approach and support SCE's future integrated planning vision that will allow us to optimize our levels of investment needed to address various types of future grid needs under increasing levels of uncertainty, including the location and magnitude of load and DER growth.

Grid Modernization Progress Report

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I. Introduction

1. Background

California Assembly Bill (AB) 242 amended Section 916.6 of the Public Utilities Code to require that "On or before February 1, 2023, and biennially thereafter, the commission, in consultation with the Independent System Operator and the Energy Commission, shall report to the Legislature and the Governor on the progress made toward modernizing the state's distribution and transmission grid and the impacts of distributed energy resources on the state's distribution and transmission grid and ratepayers."[1]

SCE has prepared this Grid Modernization Progress Report to update the California Public Utilities Commission (Commission) on SCE's overall Grid Modernization vision and approach and its Grid Modernization efforts from 2021 to 2023 and provide an overview of its near-term Grid Modernization plans. The purpose of this report is to support the Commission in its preparation of the biennial update to the Legislature on the progress of modernizing SCE's electric distribution system.

2. Grid Modernization Overview

A modern distribution grid is instrumental for addressing climate resiliency, enabling a path to carbon neutrality by 2045, facilitating customer adoption of electrified solutions in the transportation and building sectors, and more broadly, achieving California's climate and air quality goals. SCE's vision is to transform its distribution grid into a secure, flexible, networked platform that adapts to changing needs driven by higher customer DER adoption, optimizes DER value through advanced grid management, supports customer electrification needs, and ensures grid reliability and resiliency in the face of climate change. This vision requires the development of a portfolio of foundational capabilities that enable Advanced Grid Management, DER Optimization, and Customers as Grid Partners. Developing such a portfolio will require SCE to continue investing in the five categories of new technologies and functional capabilities outlined in SCE's Grid Modernization Plan (GMP).[2] Figure 1 summarizes these technologies and their necessity in realizing customer benefits.

[1] Public Utilities Code § 913.6 (a).

[2] Please refer to A.23-05-010, Test Year 2025 General Rate Case Application of Southern California Edison Company (U 338-E), SCE-02 Vol. 06 – Grid Modernization, Grid Technology, and Energy Storage, filed May 12, 2023.

Figure 1
Grid Modernization Technologies and Customer Benefits

Engineering & Planning Software Tools	A modernized distribution planning process further integrates DERs into the process and supports customer affordability by improving capital efficiency and helping customers identify DER opportunities.
Grid Management System	Advanced distribution management systems in concert with field devices will provide customers with a safe, reliable and resilient grid that powers clean energy technologies.
Communications	Modern communication systems will replace legacy technology with low latency, high bandwidth, secure communications to support modern grid capabilities.
Automation	Field devices such as advanced switches and line sensors will provide situational awareness and operational flexibility to improve customer safety and reliability and realize greater value from customer DERs.
DER Hosting Capacity Reinforcement	Technologies such as load and DER management will increase hosting capacity and drive further DER adoption, while circuits that exceed planning limits will be upgraded where needed.

II. Grid Modernization Activities from 2021 through 2023

This section summarizes the approach, status, use cases, and challenges of three aspects of Grid Modernization, which are: (1) Grid Management System (GMS), (2) Communications and Cybersecurity, and (3) Engineering and Planning (E&P) Software Tools. SCE has also made progress in Automation and DER Hosting Capacity Reinforcement, but the scope of this report follows guidance provided by the Commission and therefore does not cover these areas.

1. Grid Management System

A. Description

SCE's GMS is an advanced software platform that integrates multiple systems designed to monitor, manage, and optimize the performance of our increasingly dynamic electric grid characterized by high DER penetration. The GMS will provide SCE with the requisite capabilities to not only manage SCE's grid assets, but to also engage with customers and their DERs so that they become a core part of operating the grid. The GMS is being deployed over four Phases: (1) Advanced Distribution Management System (ADMS), (2) DER Management System (DERMS), (3) Advanced ADMS & DERMS, and (4) Grid Platform. In Phase 1, the ADMS is replacing SCE's legacy distribution management system (DMS) outage management system (OMS), such that the ADMS will provide the combined DMS/OMS functionality. In Phase 2, SCE will introduce additional DER management functions such as the short-term forecasting engine, optimization engine, and microgrid management, through the DERMS. In Phase 3, SCE will enhance the ADMS and DERMS functions implemented in Phases 1 and 2, such as by expanding mobile grid operations for field personnel, augmenting outage metrics reporting functions, and enhancing operator training system and modeling capabilities to include advanced scenarios likely to arise from higher DER penetration and changing weather conditions. One example includes expanding mobile grid operations to allow further consolidation of field personnel work into the single ADMS platform. In Phase 4, SCE will initiate Grid Platform enhancements to improve SCE's capabilities in the areas of load management (including electrical vehicle (EV) charging), substation device management, and power quality management. Additional details on the functions and expected benefits are included in the Use Cases/Benefits section below. Each GMS release is supported by organizational change management (OCM) activities and employee training on the new capabilities.

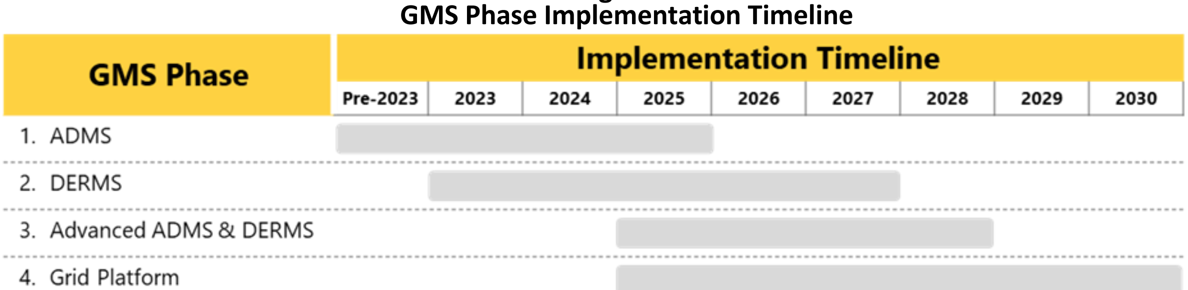
B. Status

In 2021, SCE completed deployment of the distribution SCADA platform, marking the successful achievement of a major GMS milestone for Phase 1. SCE also completed the build phase and initiated site acceptance testing (SAT) of the Phase 1 distribution management functions. Additionally, SCE initiated design activities for the Phase 2 DERMS platform.

In 2022, SCE successfully deployed the GMS data historian in the production environment, another key implementation. The data historian and distribution SCADA upgrades are highly resilient and scalable to meet SCE's future ADMS computational requirements. SCE also completed factory acceptance testing (FAT) of the ADMS distribution management and outage management functions. Figure 2 summarizes the timeline for completing the four GMS phases.

In 2023, SCE completed the SAT and technical implementation of the Phase 1 base DER management capabilities (or Base DERMS), which will allow SCE to monitor and dispatch DERs. SCE also continued its SAT activities for the DMS functions planned for deployment in 2024, which include distribution system state estimation (DSSE) and fault location, isolation and service restoration (FLISR).

Figure 2
GMS Phase Implementation Timeline



SCE is currently performing SAT of the ADMS and plans to deploy the ADMS to replace the DMS functions in 2024 (including several base DER-management capabilities). The OMS functions are planned for deployment in 2025.

C. Use Cases/Benefits

Grid management is essential to managing the grid safely and reliably. As grid operations continues to increase in complexity due to more frequent and extreme climate events and higher amounts of DERs and electrification, Grid Modernization builds upon SCE's foundational grid management capabilities to improve resilience and enhance situational awareness and grid flexibility to address these challenges. SCE is implementing the four high-level capabilities for grid management identified in Table 1.

Table 1
GMS-enabled Capabilities

Capability Category	High-level Capabilities
Grid Management Enables grid operators to monitor grid conditions in real-time, control field devices remotely, manage and optimize use of load and DERs, and monitor and manage power quality	1. Core grid management functions 2. Advanced grid management and optimization 3. Load and DER management and optimization 4. Power quality management

In Phase 1, the ADMS will enable SCE system operators, operations engineers, and other users to receive and analyze real-time information on customer energy usage, system power flows, system outages and faults, and DER performance. The ADMS will also provide the necessary interfaces between the operations control centers and grid devices, thereby facilitating SCE's handling of grid events such as planned and unplanned outages and load transfers. Additional ADMS functions include distribution system state estimation (DSSE), load volt/VAR management, mobile grid operations, and fault location, isolation, and service restoration (FLISR). The ADMS also includes basic DER management functionality that enables DER program registration and enrollment, and DER monitoring and manual control via the IEEE 2030.5 communications protocol, which that will enable SCE to communicate with DER aggregators or other third parties in accordance with SCE's Tariff Electric Rule 21[3].

In Phase 2, the DERMS will improve SCE's ability to perform short-term DER forecasting to anticipate and manage potential grid issues and optimize DER dispatch decisions. SCE will also introduce ADMS enhancements such as Public Safety Power Shutoff (PSPS) automation, advanced red flag warnings, and automatic wire down detection and isolation—all which support SCE's wildfire mitigation efforts.

In Phase 3, enhancements to the ADMS and DERMS will expand mobile grid operations to allow further consolidation of field personnel work into the single ADMS platform; augment the outage metrics reporting functions; enhance operator training system to simulate advanced scenarios likely to arise from higher DER penetration; and enhance the modeling capabilities to include DER responses to changing weather conditions, microgrid islanding scenarios, storm condition simulations, and failed equipment scenarios. This phase will also introduce storm analytics to help optimize SCE's response to storm events with available resources to accelerate service restoration.

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

In Phase 4, Grid Platform enhancements will improve SCE's capabilities in the areas of load management, substation device management, and power quality management. The load management enhancements will enable SCE to continuously manage load, including load from EV charging. This capability will include indirect load control through aggregators or other third parties, direct load control, where appropriate, and it will also support customer demand flexibility through delivery of price signals to customer devices. The substation device management enhancements include deployment of software on the Common Substation Platform that enables remote management of applications and devices operating within substations. Finally, the power quality management platform will include a model of the entire grid (transmission and distribution) that consolidates power quality sensor data to enable robust visibility and situational awareness, enables diagnosis of historical power quality issues, and simulates distributed control and DER and customer behaviors.

As noted above, between 2021 and 2023, SCE upgraded the distribution SCADA platform and GMS data historian and completed the technical implementation of the base DER management functions. These are foundational to the GMS functionalities such as distribution and outage management, load and DER management, and power quality management enabled throughout the four GMS Phases. SCE anticipates these capabilities will provide future benefits in the areas of safety, reliability, climate resiliency, decarbonization, customer empowerment and economic efficiency.

D. Challenges

The schedule has been impacted by various challenges, including vendor product development delays caused by COVID-19, supply chain constraints, the conflict in Ukraine, and the need to address cyber-related concerns with the ADMS product. As a result, SCE was required to work with the vendor to revise the schedule for Phase 1 and Phase 2. Based on this revised schedule, SCE now expects to deploy the DMS, OMS and base DER management functions between 2024 and 2026, which represents an extension of the deployment timeline for Phase 2 from five years to seven years.

2. Communications and Cybersecurity Infrastructure

A. Description

SCE currently connects distribution substations and distribution automation devices using its legacy and aging mesh radio-based communications system known as NetComm. The new Field Area Network (FAN) will replace the NetComm system with a private wireless LTE/5G system capable of supporting the capacity, speed, and connectivity needs of current and future grid devices to support automation.

In addition to FAN, the Common Substation Platform (CSP) is a computing platform (hardware and software) that acts as the communication and control hub between the operations control center and substation equipment. The CSP is designed to enable remote data acquisition and automatic control over substation devices. In addition, the CSP will also include the software-based algorithms that optimize DER and grid device performance and will provide secure communications between the substation and back-office systems.

The Grid Modernization Cybersecurity program focuses on addressing the comprehensive security and data protection needs of all new infrastructure and application assets being added through SCE's Grid Modernization program, including the FAN and CSP communications, GMS, and the external facing Engineering and Planning Software Tools.

B. Status

The Federal Communications Commission (FCC) decision to auction the Citizens Band Radio Services (CBRS) Spectrum in 2020 offered a unique acquisition opportunity as the availability of affordable spectrum to pursue private LTE technology was previously very limited. Although unanticipated at the time of SCE's Track 1 forecast in the 2021 GRC, SCE's successful procurement of the CBRS licensed Spectrum channels allows SCE to move forward with a private LTE solution for FAN instead of the upgraded mesh radio solution that was previously planned. Following the CBRS spectrum acquisition in 2020, SCE conducted competitive industry solicitations in 2021 and 2022 for the FAN equipment and services. During 2021 and 2022 SCE also focused on developing the new private LTE solution design and execution plan. SCE began its eight-year FAN deployment in 2023 by deploying the network core and the first radio access network (RAN) site, which went "on air" and was used for SCE's first 5G call in a production environment in December of 2023.

For Grid Modernization cybersecurity, SCE completed the architecture assessment and cybersecurity tool designs based on the needs of the overall Grid Modernization program. SCE also implemented the first wave of core cybersecurity tools. In 2023, SCE completed implementation and go-live of the grid extranet at SCE's grid data center to help secure field area communications.

SCE is currently deploying a second wave of prioritized cyber tools and continuing to deploy the FAN by constructing additional RAN sites as well as deploying edge radios for the grid equipment (e.g., switches, capacitor banks, etc.). SCE is also continuing to deploy CSP at targeted substations.

C. Use Cases/Benefits

Communications is foundational to enabling various grid management functions, including real-time situational awareness, analyzing and resolving grid reliability issues, as well as integrating and managing DERs. These functions are enabled by the GMS communicating securely with DERs and field devices at a speed and bandwidth that support current and future monitoring and control requirements.

SCE's new FAN is a critical component of the Grid Modernization program, enabling real-time, cyber-secure communications between grid devices (including DERs, DER aggregators and other third parties), distribution substations, and SCE's operations control centers, which will support the use of DERs to provide reliability services to the distribution system. The FAN also contributes to mitigating the cybersecurity risk in the existing legacy field network, which was ranked as one of the top nine risks in SCE's 2018 and 2022 Risk Assessment Mitigation Phase (RAMP) filings. The FAN will be capable of connecting over 250,000 devices and reducing the real-time information transfer delays from a couple of minutes under the NetComm system to a few seconds with the new FAN system. The FAN also incorporates modern cybersecurity capabilities, which will allow SCE to continue to protect data from cyber threats while supporting integration of 3rd party devices.

The CSP is a computing platform (hardware and software) that acts as the communication and control hub between the operations control center and substation equipment. The CSP is designed to enable remote data acquisition and automatic control over substation devices. In addition, the CSP will also include the software-based algorithms that optimize DER and grid device performance and will provide secure communications between the substation and back-office systems. The CSP workstream will deploy the new computing platform in distribution substations using virtualization technology to monitor, manage, control, and provide cybersecurity to substation equipment. The CSP will include redundant servers to mitigate potential server outages. SCE will manage the CSP remotely and can therefore deploy software packages remotely, including cybersecurity upgrades, from a central operations center.

The Grid Modernization Cybersecurity program focuses on addressing the comprehensive security and data protection needs of all new infrastructure and application assets being added through SCE's Grid Modernization program. This activity is necessary to prepare SCE's systems and operational processes to achieve California's 2045 net-zero carbon mandate and is focused on improving bulk power management, integration of grid and customer devices, integrated load management strategies, and customer electrification adoption and affordability.

As described above, between 2021 and 2023, SCE enabled the initial wave of cybersecurity tools and associated functionalities and implemented grid extranet at SCE's grid data center, all of which are foundational to SCE's communications and cybersecurity capabilities. SCE anticipates these capabilities will support the realization of future benefits in the areas of safety, reliability, decarbonization, customer empowerment and economic efficiency.

D. Challenges

For the Communications scope, SCE faced a significant challenge in planning and successfully participating in the FCC Spectrum Auction 105. As a result, the FAN implementation schedule had to be postponed by approximately 2 years. Secondly, the tasks of building the new FAN across 15 counties, migrating all existing 30,000+ devices, and decommissioning the legacy NetComm system are nothing short of monumental. Undoubtedly, one of the most challenging aspects for the FAN is the physical construction and commissioning of over 800 Radio Access Network (RAN) sites across the service territory over the next seven years. SCE will be maintaining different field communications environments during the transition from NetComm to FAN while prioritizing reliability and security during this changeover, which may result in new obstacles to overcome.

3. Engineering & Planning Software Tools

A. Description

SCE's E&P Software Tools will improve SCE's ability to identify DER opportunities, increase the economic efficiency of SCE's grid planning and project and portfolio management, and enhance the customer interconnection request process. SCE's E&P tools include the Grid Connectivity Model (GCM), a software model of the electrical connectivity and hierarchy of SCE's entire electrical grid; the Grid Analytics Application (GAA), which performs analytics and visualization of historical load data; the Long-term Planning Tool and Short-term Planning Tool (LTPT-SMT), which performs the load and DER forecasting, load flow analysis, and project management; the Distribution Resources Plan External Portal (DRPEP), a portal for customer access to DRP reports; and the Grid Interconnection Processing Tool (GIPT), a tool that allows customers and SCE to connect electrical generation and load to the grid more quickly and efficiently. Each E&P tool is supported by organizational change management (OCM) activities and employee training on the new capabilities provided by the tools.

B. Status

During 2021 and 2022, SCE performed multiple enhancements to the E&P tools to improve the integration between the tools and augment their capabilities. The GCM included enhancements to the distribution connectivity model and further integrated the as-built connectivity modeling information with the GAA, LTPT-SMT, and DRPEP. The GCM also supported the Wildfire Mitigation program's aerial inspection efforts by providing transformer structure-to-feeder information.

SCE enhanced the GAA by automating the creation of 8,760 hourly load profiles and performing several load profile improvements, such as calculating daily peak kilowatt-hour (kWh) data, enhancing the user interface, performing backfill of historical Advanced Metering Infrastructure (AMI)/DER profile data for new nodes, and automating the interface with the GCM. The time-series based load and generation profiles prepared by GAA are foundational to enabling SCE's transition to profile-based planning.

SCE implemented several planning functions in LTPT-SMT, including the partial implementation of load flow analysis. SCE used this as part of its annual planning process beginning in 2022 for a limited part of its distribution system and plans to use it to support systemwide profile-based planning in 2025. SCE performed enhancements to improve weather station data accuracy and made other data cleansing and validation modifications, including integrating additional internal and external planning inputs into forecasting analysis, enabling profile-based power system analysis, and integrating ICA with forecasting analysis to inform system planning.

SCE performed DRPEP enhancements to continue publishing the DRP reports, GNA, DDOR, LNBA and ICA,[4] address new Commission requirements for publication, automate the 15/15 Rule,[5] and address additional capabilities consistent with the Commission decision on the ICA Working Group's (WG) Final ICA WG Long Term Refinements Report. Additional requirements included

[4] Grid Needs Assessment, Distribution Deferral Opportunity Report, Locational Net Benefits Analysis and Integration Capacity Analysis, respectively.

[5] The "15/15 Rule" requires that any aggregated information provided by SCE must be made up of at least 15 customers and a single customer's usage must not exceed 15% of the total usage of an assigned category. See, D.97-10-031.

identifying the location of all approved transmission projects, adding Fire Map layers, and implementing a microgrid portal using the DRPEP platform.

Finally, SCE implemented the Wholesale Distribution Access Tariff (WDAT) DER interconnection tariff process workflows into GIPT to support customer application submittal and review, and technical evaluation and contract development for WDAT applications.

In 2023, SCE continued to deliver additional planning capabilities, enhance those already enabled, and address challenges implementing system-wide load flow analysis. SCE enhanced the GCM services and connectivity modeling to support site acceptance testing of SCE's Advanced Distribution Management System (ADMS) and improved the integration of GCM with DRPEP.

SCE enhanced its ability to perform capacity analysis by making several improvements to load profile development. This included automating the syncs between the modules that provide the usage data and construct profiles, enhancing the GAA interface, and introducing the ability to aggregate user-sourced meter groupings to prepare load profiles.

To enhance the forecasting process, SCE also began the transition from circuit-level forecasting to transformer structure-level forecasting, which should improve the precision and efficiency of SCE's capacity planning and ICA processes. This also included developing an approach to aggregating transformer structure-level forecast to various other nodes upstream of the transformer in the planning hierarchy (e.g., circuits and substations). SCE also automated the processing and loading of weather data used for forecasting.

SCE performed upgrades to DRPEP and the microgrid portal, including adding new layers for distribution circuits and PSA locations, enabling customers to download ICA files in bulk, and other technical upgrades. SCE also added heat maps to DRPEP to allow customers to more easily identify potential locations for DER siting.

Finally, SCE enhanced GIPT to enable WDAT contract management and legacy project migration into GIPT and implemented the Transmission Owner Tariff (TOT) interconnection tariff application submittal and review processes. SCE also augmented the GIPT's DER data manager functionality, which provides DER information to GCM for inclusion in the grid connectivity modeling.

Over the next few years, SCE will continue to build upon the progress achieved to-date by delivering additional planning capabilities, enhancing those already enabled, and addressing challenges implementing system-wide load flow analysis. This will include completing SCE's transition to profile-based capacity planning by creating a dashboard that aggregates information from the various E&P software tools and enables system planners to evaluate the entire system and generate planning summaries. This will also enable SCE to perform end-to-end planning for multiple growth scenarios, accelerate the consideration of DERs as potential grid solutions upfront within the capacity planning process, and support SCE's future integrated planning approach that will allow us to optimize our levels of investment needed to address various types of future grid needs and drivers under increasing levels of uncertainty.

C. Use Cases/Benefits

As the demands placed on our grid continue to grow, including those from DER growth and climate-driven events, SCE needs to improve its ability to address these growing needs while maintaining customer affordability. SCE's E&P capabilities help to integrate DERs into SCE's electric system planning processes, consider multiple future load and DER growth scenarios to better identify grid needs, and determine no-regrets solutions to resolve the forecasted grid needs. This requires more granular DER and load forecasting, power flow modeling and analysis to identify grid needs and potential solutions at the sub-circuit level. This also necessitates streamlined interconnections of customer DERs and load. SCE is implementing the five high-level E&P capabilities identified in Table 2.

Table 2
E&P Software Tools-Supported Capabilities

Capability Category	High-level Capabilities
Engineering & Planning Integrates DERs into grid planning processes, increases precision of grid needs and solutions identification, enables scenario analysis, and supports optimal project and portfolio management	1. Electrical connectivity and hierarchy modeling
	2. Time series-based capacity planning
	3. Project and portfolio optimization and management
	4. DER hosting capacity and deferral opportunity reporting
	5. Customer interconnection request automation

Between 2021 and 2023, SCE focused on integrating the GCM with the other E&P tools to improve the efficiency of the overall planning process and reduce the need for manual processes and rework that can result from manual processes. SCE advanced the E&P tools to support SCE's migration to profile-based capacity planning by enhancing the performance of the tools (such as through weather data improvements and implementing functions to identify discrepancies between the tools; and transitioning to transformer-structure level forecasting), and partially implementing the load flow analysis engine. These functions have supported SCE's current hybrid approach to profile-based planning that uses profile-based load and DER forecasts to identify potential violations. In 2025, SCE plans to use load flow analysis to identify grid needs with much greater temporal and spatial precision. This should improve the economic efficiency of the annual capacity planning process while also improving the potential to identify opportunities to defer traditional infrastructure investments with DERs. In addition to the planning tool uses, SCE also began using GIPT to process WDAT interconnection requests in 2022 and completed the first phase of implementing TOT in 2023.

D. Challenges

Challenges with the load flow analysis tool have limited SCE's ability to perform systemwide load flow analysis. These challenges include (1) the limited scalability of the tool to handle SCE's approximately 4,500 distribution circuits, (2) its inability to analyze multi-voltage substations, (3) network configuration challenges (which equates to about 20% of SCE's distribution infrastructure), (4) tool instability, and (5) an inability to view and interact with the analysis results. SCE expects to overcome these challenges and complete its transition to profile-based planning within the next few years.

III. Conclusion

During 2021 and 2022, SCE made substantial progress with the GMS, Communications and Cybersecurity, and E&P Software Tools. For the GMS, SCE deployed the distribution SCADA platform and data historian, and completed the build phase of the ADMS distribution management functions. In 2023, SCE completed the SAT and technical implementation of the Phase 1 base DER management capabilities, which will allow SCE to monitor and dispatch DERs. SCE also continued its SAT activities for the DMS functions planned for deployment in 2024. SCE is currently performing site acceptance testing of the ADMS and plans to deploy it to replace the DMS functions in 2024 (including several base DER-management capabilities). The OMS functions are planned for deployment in 2025. As capabilities are deployed, the GMS will work in concert with field devices to provide customers with a safe, reliable, and resilient grid that powers our customers' clean energy choices.

In the area of Communications and Cybersecurity, during 2021 and 2022, SCE conducted competitive industry solicitations for the FAN equipment and services and developed the new private LTE solution design and execution plan. In terms of cybersecurity, SCE implemented the first wave of core cybersecurity tools and the grid extranet at SCE's grid data center. In 2023, SCE initiated its eight-year FAN deployment by deploying the network core components and constructing the first RAN site. SCE also completed implementation and go-live of the grid extranet at SCE's grid data center to help secure field area communications. SCE's modern communications systems, including the FAN and CSP, are replacing SCE's legacy technology with low latency, high bandwidth, secure communications to support modern grid capabilities.

The E&P Software Tools received multiple enhancements during 2021 and 2022 to increase the integration between the respective tools and to augment their capabilities. Such enhancements included improving the integration of the GCM with the other planning tools, partial implementation of the load flow analysis tool, and completion of WDAT in GIPT. In 2023, SCE continued to deliver additional planning capabilities, enhance those already enabled, and address challenges implementing system-wide load flow analysis. Over the next few years, SCE will continue to enhance the E&P Software Tools to further advance our system planning approach and support SCE's future integrated planning vision. This in turn will allow SCE to optimize the levels of investment needed to address various types of future grid needs under increasing levels of uncertainty, including the location and magnitude of load and DER growth.

CPUC ENERGY STORAGE PROCUREMENT STUDY - ATTACHMENTS SUMMARY

A. Historical Benefit-Cost Analysis and Scoring of Energy Storage Projects in California

A 5-year study period from 2017-2021 analyzing the benefits and costs of energy storage operations in California.

B. Cost-effectiveness of Future Procurement

A study of energy storage's declining value and change in cost-effectiveness as the state procures more energy storage to meet its clean energy goals.

C. Cost-effectiveness of Peaker Replacement

A study of the potential of energy storage to replace gas-fired peaking units that are mainly used for grid reliability but produce significant amounts of greenhouse gases.

D. Procurement Policy Case Studies

Case studies of highly effective energy storage procurement policies and programs in New York, Hawaii, Arizona, Nevada, and Texas.

E. End Uses and Multiple Applications

A brief overview of various services and applications of energy storage such as energy arbitrage, ancillary services, resource adequacy, and many more.

F. Safety Best Practices

Includes case studies of thirteen safety events (incidents) and lessons learned, analysis of current best practices, and next steps to improve risk management and safety.

G. End of Life Options for Lithium-Ion Batteries

An overview of options, scalability, and tradeoffs for end-of-life of lithium-ion batteries.

H. Stakeholder Engagement

An overview of stakeholder process in the report, key issues raised, and how their feedback and engagement supplemented this report.

CPUC SCALING UP AND CROSSING BOUNDS: ENERGY STORAGE - ATTACHMENTS SUMMARY

A. Historical Energy Storage Benefits

Analysis of more than 6 gigawatts of energy storage operations in California and the benefits contributed to grid optimization, renewables integration, and greenhouse gas emissions reduction.

B. Historical Energy Storage Performance during Grid-Stressed Periods

Investigates patterns and challenges in energy storage performance during CAISO systemwide grid emergency events from 2020 to 2023 and provides insight on their contributions to system reliability and capacity needs in California.

C. Multi-use Application Analysis (MUA) with Outage Mitigation

Analysis of customer outage mitigation solutions from 8 locations throughout California that represent diverse environments, communities, geographies, weather conditions, and electricity market conditions.

D. Multi-use Application Analysis (MUA) with Distribution Deferral

Analysis and market value potential of the 63 out of 98 potential projects selected by the IOUs from 2017-2023 for distribution deferral solutions – deferral refers to upgrading distribution needs using DERs as an alternative to traditional solutions.

E. Case Study Fact Sheets

Information of 10 microgrids used in this study including location, project and interconnection status, configuration, primary use case, and other key characteristics.

APPENDIX A – GLOSSARY OF TERMS

Advanced Distribution Management System: (ADMS) See Distribution Management System.

Advanced Metering Infrastructure: (AMI) refers to the full energy consumption data measurement and collection system that includes advanced meters / Smart Meters at the customer site, communication networks between the customer and utility, and data collection and management systems that make the information available to the utility.

Behind-the-Meter: (BTM) refers to electrical equipment and technologies that are interconnected on the customer's side of the electric meter. Customer-sited distributed energy resources (DERs) such as rooftop solar PV arrays are one of the most common examples of BTM resources.

CAISO: California Independent System Operator maintains reliability on one of the largest and most modern energy grids in the world, and operates a transparent, accessible wholesale energy market.

Circuit: a network of wires that carries power from substations or distributed generation to local load areas such as commercial and residential areas.

Demand Response: (DR) refers to changes in electricity usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time or in response to incentive payments. These price changes and payments are designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.

Distributed Energy Resources: (DERs) include distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies. DERs are connected to the distribution grid both behind the customer's meter (BTM) and in front of the customer's meter (IFOM).

Distributed Energy Resources Management System: (DERMS) is a software platform typically integrated with ADMS that manages the integration and optimization of DERs in the grid.

Distribution Deferral Opportunity Report: (DDOR) a report that, along with the grid needs assessment (GNA), provides a characterization of circuits according to cost-effectiveness, forecast certainty, and market assessment to help prioritize projects on the candidate deferral shortlist. The annual DDOR filing also includes a proposed work plan and agenda for the Distribution Planning Advisory Group (DPAG), which DPAG-participating CPUC technical staff, an independent professional engineer providing technical consultation, non-market participants, DER market participants, and IOUs may comment on prior to finalization. D.24-10-030 updated DDOR to Distribution Upgrade Project Report (DUPR) to refocus from deferrals to reporting and transparency.

Distribution Feeder: (or feeder) refers to a circuit that carries power from a distribution substation to local load areas such as commercial and residential areas.

Distribution Investment Deferral Framework: (DIDF) a framework designed to identify opportunities where future distribution system upgrades can be deferred or avoided through distributed energy resource deployment as "non-wires alternatives". D.24-10-030 has updated "the entire DIDF process from a distribution investment deferral solicitation process to a process focused on the facilitation of improving transparency of the Distribution Planning Process and monitoring distribution planning improvements"

Distribution Management System: [DMS, also referred to as Advanced Distribution Management System (ADMS)] a software platform that can monitor and control the distribution system efficiently and reliably.

Distribution Resources Plan: (DRP) refers to the plans that each of the investor-owned utilities was required to develop to propose contracts, tariffs, or other distributed energy resources procurement mechanisms to maximize the locational benefits and minimize the incremental costs of distributed resources. The DRPs also identify additional spending necessary to integrate distributed energy resources into distribution planning and to modernize their electric grids. The plans also identify the barriers to the deployment of distributed energy resources. DRP also refers to the namesake CPUC proceeding that developed the DRPs.

Distribution Planning Advisory Group: (DPAG) a body consisting of DER market participants, non-market participants, IOUs, CPUC technical staff, and an independent professional engineer providing technical consultation, who together advise the utilities on the selection of distribution deferral opportunities and provide input on the development of competitive solicitation for distributed energy resources.

Energy Storage: Mechanical, chemical, and thermal technologies as defined in California Assembly Bill 2514 (Skinner, 2010) and clarified in CPUC Decision 16-01-032.

Electric Tariff Rule 21: (or Rule 21) refers to the tariff governing the utilities' interconnections of distributed energy resources.

EV: (Electric vehicle) See plug-in electric vehicle.

Fast Track Process: (or fast track applications) a streamlined review process within Rule 21 that is based on multiple evaluation screens for interconnecting net energy metering, non-export, and small exporting facilities.

Fault Location Isolation and Service Restoration: (FLISR) a software system integrated into the utilities' outage management system that limits the impact of outages by quickly opening and closing automated switches and reconfiguring the flow of electricity through a circuit. By reconfiguring the flow of electricity, FLISR can minimize the number of customers impacted by an outage and isolate the outage to reduce restoration times. With FLISR, outages that may have been one- to two-hours in duration can be reduced to less than five minutes.

General Rate Case: (GRC) is a proceeding used to address the costs of operating and maintaining the utility system and the allocation of those costs among customer classes. GRCs also ensure investor-owned utilities (IOUs or utilities) get their rate of returns in compliance with *Bluefield* and

Hope decisions.[23] For California's three large IOUs, GRCs are parsed into two phases. Phase I of a GRC determines the total amount the utility is authorized to collect, while Phase II determines the share of the cost each customer class is responsible for and the rate schedules for each class. Each large electric utility files a GRC application every four years.

Gigawatt: (GW) a unit of electric power equal to one billion watts.

Grid Needs Assessment: (GNA) an assessment of the distribution grid that identifies grid needs at the substation level and/or feeder level. Forecast needs, or deficiencies, are associated with as many as four distribution services that DERs can provide: distribution capacity, voltage support, reliability (back-tie) and resiliency.

High Fire Threat District: (HFTD) refers to the high fire threat regions in the CPUC's Fire-Threat Map which was adopted by the CPUC in Decision D.17-12-024. The map consists of three fire-threat tiers (Zone 1, Tier 2, and Tier 3) that have increasing levels of risk of wildfires associated with overhead utility power lines and facilities that also support communication facilities.

Integrated Capacity Analysis: (ICA) quantifies the available hosting capacity of every distribution circuit in the utilities' service territories to integrate distributed energy resources without triggering grid upgrades.

Integrated Distributed Energy Resources: (IDER) refers to the CPUC's strategy for the utilities to integrate customer demand-side programs, such as energy efficiency, self-generation, advanced metering, and demand response, in a coherent and efficient manner. IDER also refers to the IDER proceeding, which focuses on developing sourcing mechanisms for the procurement of DERs that advance distribution planning objectives.

Hybrid Resource: In the context of the CAISO marketplace, multiple mixed-fuel resources (referred to as "components") behind a single point of CAISO interconnection, such as solar PV and battery energy storage, which participate as a combined resource with a single Resource ID. See also co-located resource. Both co-located and hybrid resources may be subject to an aggregate output constraint at the CAISO point of interconnection.

Inverter: an electronic device that converts DC power to AC power and is necessary to connect most distributed energy resources to the grid. See Smart Inverter.

IOU: investor-owned utility. Typically refers to the three major investor-owned utilities: Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E)

Island Mode: (or islanding) refers to when a circuit or microgrid operates in isolation from the distribution grid and can continue to serve power through DERs when the distribution grid experiences outages and can no longer serve the circuit or microgrid with electricity from the bulk power system.

Kilowatt: (kW) a unit of electric power equal to one thousand watts.

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23 Bluefield Water Works & Improvement Co. vs Public Service Commission of West Virginia (1923) 262 U.S. 679. Federal Power Commission vs. Hope Natural Gas Co. (1944) 320 U.S. 591

Load: the total amount of power needed to meet all demand on the grid at any given time.

Locational Net Benefits Analysis: (LNBA) a tool that can determine optimal locations for DER deployment based on cost-effective opportunities for DERs to defer or avoid traditional distribution system investments.

Megawatt: (MW) a unit of electric power equal to one million watts.

Microgrid: As defined in California Public Utilities Code Section 8370(d), a microgrid is an interconnected system of loads and energy resources, including, but not limited to, distributed energy resources, energy storage, demand response tools, or other management, forecasting, and analytical tools, appropriately sized to meet customer needs, within a clearly defined electrical boundary that can act as a single, controllable entity, and can connect to, disconnect from, or run in parallel with, larger portions of the electrical grid, or can be managed and isolated to withstand larger disturbances and maintain electrical supply to connected critical infrastructure.

Multiple-Use Applications: (MUA) refers to the multiple benefits and services that energy storage devices can provide to the grid to increase the economic value provided.

Net Peak: refers to the hours of the day during which total demand load minus the renewable resource generation tends to be the highest.

Non-Generator Resource: (NGR) model is the primary model designed for today's common storage technologies like lithium-ion batteries, which allows them to operate as either load or generators, dispatched at any level within their full operating range, subject to charge, discharge, and state-of-charge (SOC) limits.

Order Instituting Rulemaking: (OIR) is a document that launches an investigatory proceeding in the CPUC to consider the creation or revision of rules, general orders, or guidelines in a matter affecting more than one utility or a broad sector of the industry. Comments and proposals are submitted in written form. Oral arguments and or evidentiary hearings are sometimes allowed.

On-Peak or Gross Peak: refers to the hours of the day during which demand for electricity tends to be the highest.

Outage Management System: (OMS) a computer system used by electric distribution system operators to assist in restoration of power.

PEV: (plug-in electric vehicle) is a type of zero emission vehicle (ZEV), which has no tail pipe emissions. A plug-in electric vehicle is any motor vehicle that can be recharged from an external source of electricity, such as wall sockets, and the electricity stored in the rechargeable battery packs drives or contributes to driving the wheels. With 100% clean energy sources, a PEV can become a ZEV.

Public Safety Power Shutoff: (PSPS) is a wildfire mitigation measure where a utility pre-emptively turns off electricity to specific geographic areas when gusty winds, dry conditions, and heightened fire risks are forecasted. PSPS events are also referred to as de-energization events.

Reliability: the ability of the electric grid to deliver electricity in the quantity and with the quality demanded by customers while minimizing service interruptions. Reliability is measured using numerous metrics including the number of outages, frequency of outages, and outage duration.

Resiliency: the ability of the grid to resist failure, reduce the magnitude and/or duration of disruptive events to the grid, and recover from disruptive events.

Resource Adequacy (RA): a regulatory requirement designed to provide sufficient resources to the California Independent System Operator to ensure the safe, reliable operation of the grid in real time. RA is a planning reserve margin of available generation resources.

Self-Generation Incentive Program (SGIP): a CPUC program that provides incentives to support existing, new, and emerging distributed energy resources by providing rebates for qualifying distributed energy systems such as energy storage installed on the customer's side of the utility meter

SIOWG: Smart Inverter Operationalization (SIO) Working Group is an ad-hoc collaborative stakeholder committee that provides input and recommendations to the CPUC Rule 21 proceeding in various matters of smart inverters.

Supervisory Control and Data Acquisition: (SCADA) is a system of software and hardware elements that allow distribution system operators to remotely gather, monitor, and process data from sensors deployed along the distribution system.

Smart Inverter: a smart inverter is an inverter that performs functions that, when activated, can autonomously provide grid support during excursions from normal system conditions of operational voltage and frequency. Smart inverters also provide safety features, and communications capabilities. See Inverter.

Smart Meter: (also known as an advanced meter) an electronic meter that records consumption of electric energy in intervals of an hour or less and communicates that information at least daily back to the utility for monitoring and billing. A smart meter enables customers to view their consumption hourly to enable improved energy management and responsiveness to time-variant energy price signals. See Advanced Metering Infrastructure.

Use Case: A technical, operational, and/or financial model for developing and operating an energy storage resource to provide a specific set of services (e.g., microgrid use case). Use cases are varied and may or may not "stack" services within a grid domain (e.g. customer outage mitigation plus bill savings) and/or across grid domains (e.g., community outage mitigation plus energy services to the bulk grid).

Volt Amperes Reactive: (VAR) a measure of reactive power, which exists in an AC circuit when the current and voltage are not in phase. Certain types of loads absorb or produce reactive power, so its presence on the distribution grid is unavoidable. However, reactive power imbalances cause abnormal voltages, so VARs must be managed to keep line voltages within acceptable ranges to protect customer devices.

Volt/VAR Control: (also known as Volt/VAR Optimization) refers to the process of managing voltage levels by injecting or absorbing reactive power (measured in VAR) on the distribution system.