Application No.: A.19-08-____
Exhibit No.: SCE-02, Vol. 4, Part 1
Witnesses: T. Boucher
V. Kaushik

SOUTHERN CALIFORNIA
EDISON®

An *EDISON INTERNATIONAL®* Company

(U 338-E)

2021 General Rate Case

Grid Modernization, Grid Technology, and Energy Storage

Before the

Public Utilities Commission of the State of California

Rosemead, California
August 30, 2019

SCE-02, Vol. 4, Part 1: Grid Modernization, Grid Technology, and Energy Storage

Table Of Contents

Table Of Contents (Cont'd)

SCE-02, Vol. 4, Part 1: Grid Modernization, Grid Technology, and Energy Storage

Table Of Contents (Cont'd)

Section	Page	Witness

SCE-02, Vol. 4, Part 1: Grid Modernization, Grid Technology, and Energy Storage

Table Of Contents (Cont'd)

Section	Page	Witness

Table Of Contents (Cont'd)

Table Of Contents (Cont'd)

SCE-02, Vol. 4, Part 1: Grid Modernization, Grid Technology, and Energy Storage

Table Of Contents (Cont'd)

Section	Page	Witness

SCE-02, Vol. 4, Part 1: Grid Modernization, Grid Technology, and Energy Storage

Table Of Contents (Cont'd)

SCE-02, Vol. 4, Part 1: Grid Modernization, Grid Technology, and Energy Storage

Table Of Contents (Cont'd)

Section	Page	Witness

I.

INTRODUCTION

A. Content and Organization of Volume

System Augmentation Business Planning Group (BPG) includes the activities Southern California Edison Company (SCE) performs to make modifications to the electrical system. Modifications to SCE electrical system are driven by many factors including changes in technology, load growth from existing customers, connecting new customers to the grid, and other modifications requested by SCE's customers. System Augmentation BPG Volume 4 testimony is organized into three Parts (chapters), composed of the following Business Planning Elements (BPEs):

System Augmentation Part 1:

- Grid Modernization
- Grid Technology Assessments, Pilots & Adoption
- Energy Storage

System Augmentation Part 2:

- Load Growth
- Transmission Projects
- Engineering

System Augmentation Part 3:

- New Service Connections
- Customer Requested System Modifications

Each chapter includes analyses for each BPE of: (1) regulatory and compliance requirements, (2) operation and maintenance expense (O&M) and capital funding authorized in the 2018 General Rate Case (GRC) compared to recorded amounts in 2018, and (3) the 2021 O&M Test Year forecast relative to historical spending and (4) the 2019 – 2023 capital expenditure forecast.

B. Summary of O&M and Capital Request

Volume 4, System Augmentation, presents SCE's total requests for the System Augmentation BPG of $35 million (constant 2018 dollars) in O&M expenses for the 2021 Test Year and $6,923 million in capital expenditures for 2019-2023, and are presented in Figure I-1 and Figure I-2.

Figure I-1
System Augmentation Part 1 O&M Expenses 2021 Forecast
(Total Company Constant 2018 $Millions)

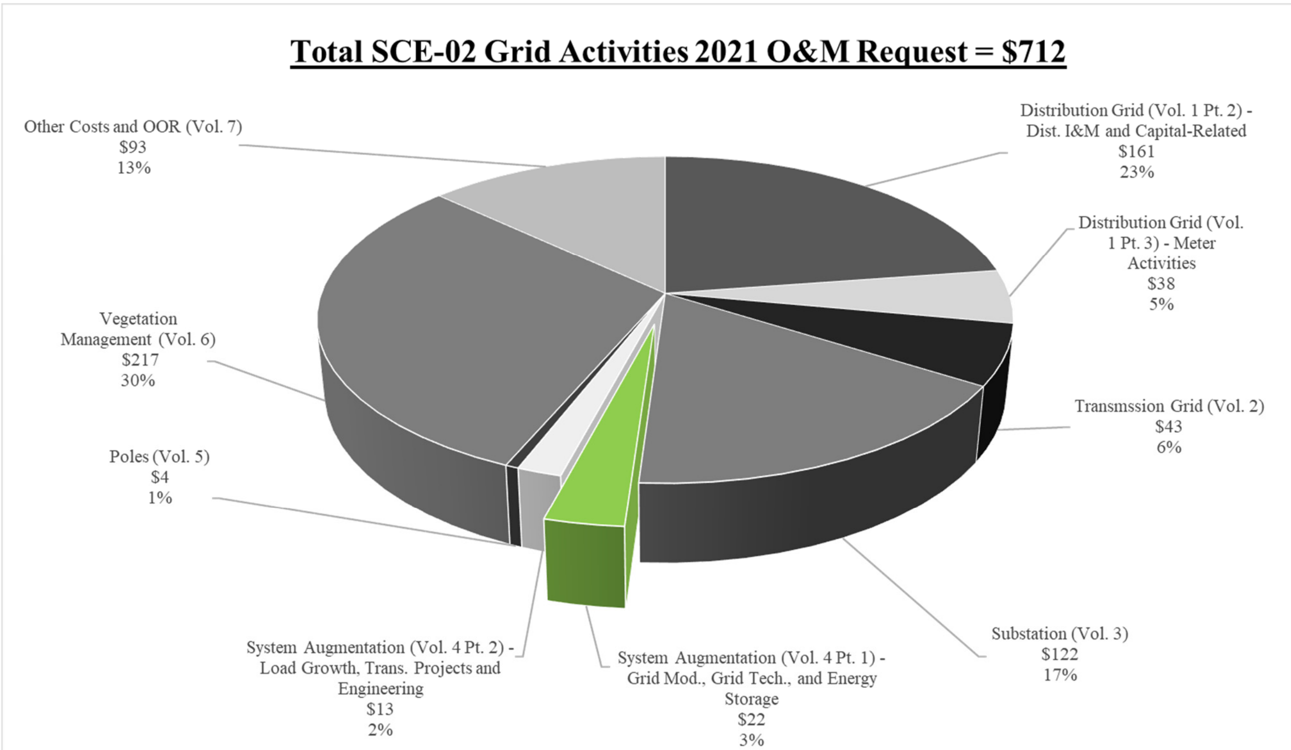
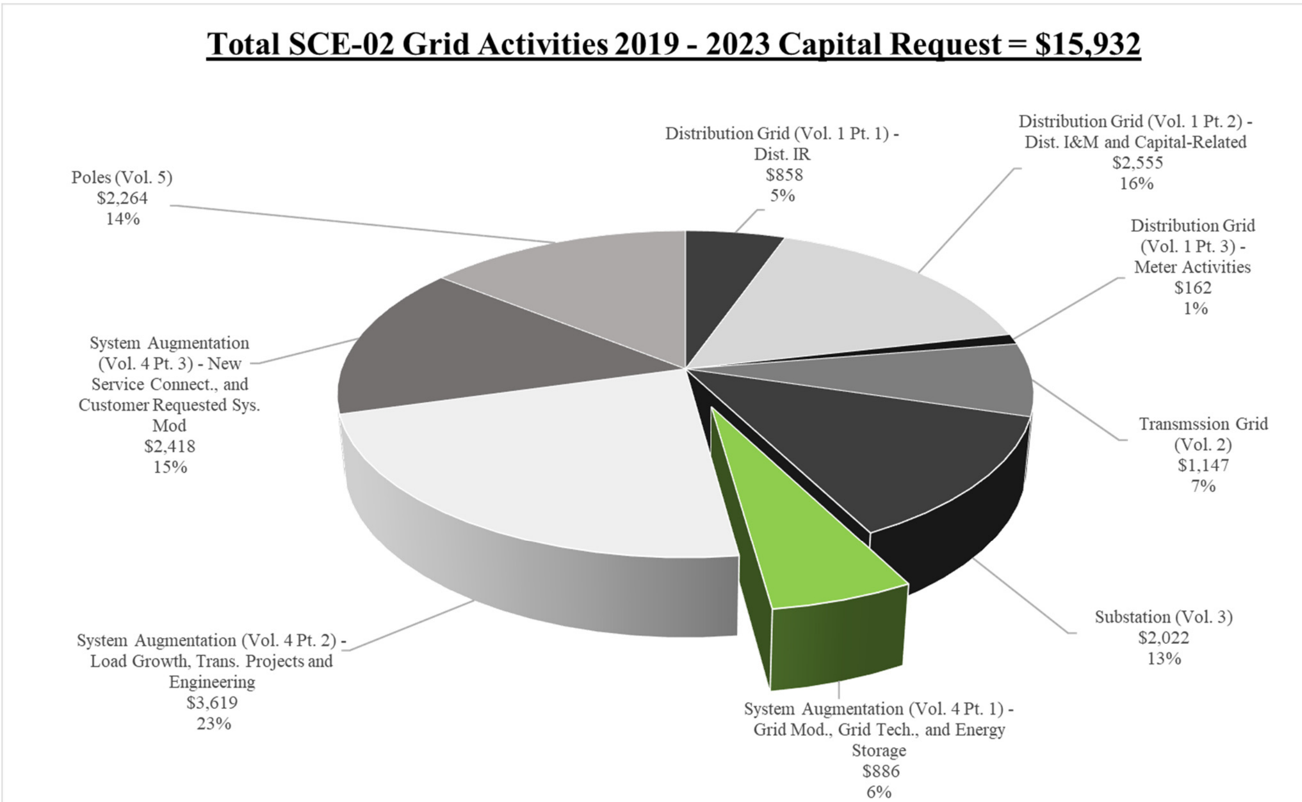


Figure I-2
System Augmentation Part 1 Capital Expenditures 2019-2023
(Total Company Nominal $Million)



SCE’s requests for System Augmentation Part 1 include $22.1 million (constant 2018 dollars) in O&M expenses for the 2021 Test Year and $886.2 million in capital expenditures for 2019-2023 for Grid Modernization, Grid Technology and Energy Storage GRC activities. A further breakdown of the O&M expenses and capital expenditures in this part for System Augmentation work activities are shown below in Table I-1 and Table I-2.

Table I-1
System Augmentation Part 1 O&M Expenses by Chapter
2021 Forecast
(Constant 2018 $Millions)

	2021 Total
Grid Modernization	$7.3
Grid Technology Assessments, Pilots & Adoption	$13.0
Energy Storage	$1.8
Totals	**$22.1**

Table I-2
System Augmentation Part 1 Capital Expenditures 2019-2023 by Chapter
(Total Company Nominal $Millions)

	2019	2020	2021	2022	2023	2019 - 2023 Total
Grid Modernization	$156.7	$119.4	$184.7	$186.0	$174.9	$821.8
Grid Technology Assessments, Pilots & Adoption	$4.5	$6.2	$2.2	$2.4	$1.8	$17.0
Energy Storage	$18.6	$19.3	$9.5	-	-	$47.4
Totals	**$179.8**	**$144.8**	**$196.4**	**$188.5**	**$176.7**	**$886.2**

II.

GRID MODERNIZATION

A. Overview

As discussed by Mr. Payne in SCE-01, Volume 1, a modern distribution grid is instrumental in addressing wildfire resiliency, enabling carbon reduction in the electricity sector,[1] facilitating customer adoption of electrified solutions in the transportation and building sectors, and more broadly, achieving California's climate and air quality goals.[2] SCE has made progress since first introducing Grid Modernization in its 2018 GRC request; however, there is much work to be done. Grid Modernization is intended to accelerate the adoption and integration of renewables and other sustainable resources on the distribution grid in accordance with California Public Utilities Code §769.[3] The Commission has stated:

> A modern grid allows for the integration of distributed energy resources (DERs)[4] while maintaining and improving safety and reliability. A modern grid facilitates the efficient integration of DERs into all stages of distribution system planning and grid 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.[5]

SCE supports the Commission's definition of a modern grid and has prepared a 10-year Grid Modernization Plan (GMP),[6] as required by the Commission in D.18-03-023.[7] Within the GMP, SCE discusses its plan for realizing its Grid Modernization vision, which is consistent with the Commission's definition. The GMP describes SCE's Grid Modernization investments over the next ten years, explaining SCE's near-term focus on DRP compliance, asset obsolescence, and evolving cybersecurity threats. SCE below describes the primary drivers for its Grid Modernization investments. These drivers

---

1 The 100 Percent Clean Energy Act of 2018, SB 100.

2 California Global Warming Solutions Act of 2006, AB 32.

3 Interpreted by the California Public Utilities Commission (Commission) in Decision No. (D.) 18-03-023 in the Distribution Resources Plan (DRP) proceeding R.14-08-013.

4 PUC §769. (a) For purposes of this section, "Distributed Energy Resources" means distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies.

5 D.18-03-023, p. 7.

6 Appendix A contains SCE's GMP.

7 *Id*., pp. 21-22 and Ordering Paragraph (OP) 4 on pp. 34-35.

compliment SCE's primary and ongoing focus on safety, reliability and wildfire resiliency. This will require SCE to augment its grid planning and operations capabilities by deploying an integrated cyber-secure[8] suite of automation, communications infrastructure, Grid Management System (GMS), and electric system forecasting and analytics applications, and ensuring available capacity to integrate DERs into the electric grid.

SCE's recent Grid Modernization efforts have focused on compliance with DRP decisions that require complex modifications to distribution grid planning and operations.[9] SCE has developed and implemented short-term software enhancements and process improvements to satisfy the reporting requirements of the Grid Needs Assessment (GNA) and Distribution Deferral Opportunity Report (DDOR). SCE continues to investigate the appropriate methodologies to identify location-specific needs across the system. For example, D.18-02-004 requires SCE to provide more grid data publicly to facilitate opportunities for DERs to defer the need for traditional distribution infrastructure expenditures.[10] SCE will continue transforming its system planning processes to support expansion of DERs while addressing system reliability and providing net customer benefits. This includes developing planning tools that enable profile-based analysis[11] of all distribution grid assets, risk-based distribution portfolio management,[12] and locational net-benefits analysis.[13]

---

[8] Please refer to SCE's cybersecurity testimony, SCE 4-Vol 3.

[9] *See* D.17-09-026, D.18-02-004, and D.18-03-023.

[10] *See* D. 18-02-004, OP 2, pp. 83-89.

[11] SCE's traditional forecasting approach consists of identifying a single point-in-time during the year when system load is highest, and then forecasting the growth in peak load over the forecasting period. Under the time-series (or profile-based) forecasting approach, annual load profiles with 8,760 data points (one for each hour in the year) are generated using historical grid data.

[12] SCE is enhancing its annual grid planning processes to identify the grid need projects and consider DERs as potential alternatives for traditional grid infrastructure upgrades. This includes augmenting its project identification and scenario analysis capabilities so that SCE pursues projects that are risk-informed and benefit customers. The modified process helps to ensure sufficient resources are available to support projects from initiation to completion.

[13] Assembly Bill (AB) 327 of 2013 added section 769 to the California Public Utilities Code, requiring each California Investor Owned Utility (IOU) to submit a DRP proposal "to identify optimal locations for the deployment of distributed resources…" using an evaluation of "locational benefits and costs of distributed resources located on the distribution system" based on savings distributed energy resources provide to the electric grid or costs to utility customers. Locational Net Benefits Analysis (LNBA), which evaluates DERs' benefits at specific locations is one of several new analytical methods needed to achieve the future envisioned in the DRP - one where DERs are deployed at optimal locations, times, and quantities so that their benefits to the grid are maximized and utility customer costs are reduced.

SCE is focused on addressing the obsolescence of key software and communications technologies, which includes updating these systems with modern cyber-secure solutions. SCE will replace its aging Distribution Management System (DMS) and Outage Management System (OMS), which have limited functionalities, with the GMS. The three primary components of the GMS include an Advanced Distribution Management System (ADMS), a Distributed Energy Resources Management System (DERMS) and advanced applications. The GMS will receive real-time information from field devices and DERs and analyze it to support grid operations in responding to (or preparing for) grid events such as planned and unplanned outages and load/generation transfers. The GMS may evolve into a platform for a distribution system market in which DERs will be able to operate in a manner that is beneficial to distribution system operations and possibly meet wholesale energy needs in the California Independent System Operator (CAISO) market.

SCE's existing wireless field area network (FAN) is vulnerable to evolving cybersecurity threats and does not support SCE's planned automation capabilities. By replacing the FAN, expanding the fiber optic cable (wide area network or WAN), and adopting internet-based protocols, SCE will update the telecommunications vital to its automated grid functions, enhance cybersecurity, and implement automation that helps reduce or avoid customer outages. Expanding the WAN is necessary to provide connectivity between the FAN and GMS.

The remainder of this overview section describes the drivers, capabilities, and customer benefits of SCE's Grid Modernization program and our architecture and engineering approach to designing a modern grid. The section concludes with a summary of the regulatory background and compliance requirements driving SCE's request and is followed by sections that describe the 2018 GRC Decision, the O&M expense forecast for Transmission and Distribution (T&D) Deployment Readiness activities and Information Technology (IT) Project Support, and the proposed capital expenditures for each workstream.

SCE forecasts $7.272 million in O&M in Test Year 2021 to manage all Grid Modernization deployment activities discussed in this chapter. This includes $1.539 million for T&D Deployment Readiness and $5.734 million for IT Project Support. SCE forecasts $821.8 million in capital expenditures in 2019 - 2023. This includes $120.3 million in engineering and planning software tool investments, $229.5 million in automation investments, $278.1 million in communications investments, $192.0 million in GMS investments, and $2.0 million in DER hosting capacity reinforcement investments.

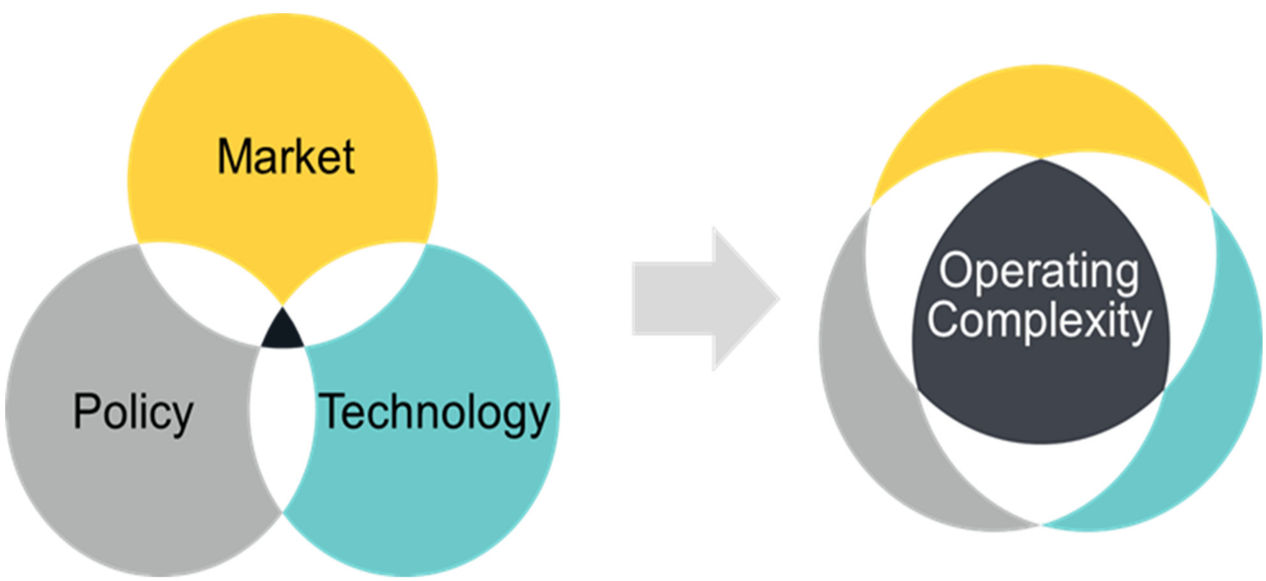
1. Drivers, Capabilities and Benefits

The electricity industry is undergoing a fundamental transformation in how energy is created and consumed, driven by a maturing market for DERs and a policy environment that supports DER adoption. Meanwhile, advances in energy and information technology are rendering legacy utility systems obsolete while also providing new opportunities for utilities to adapt to an increasingly complex operating environment. This transformation drives SCE's need to modernize its distribution system by implementing new planning and operations capabilities. By adapting to this new environment, in part by implementing Grid Modernization capabilities, SCE can deliver meaningful benefits to customers.

a) Drivers

Three sets of factors drive the transformation of the electricity industry: market developments, state and federal policies, and technology considerations. The acceleration and convergence of these factors increases the complexity and difficulty of planning and operating the distribution grid infrastructure, as illustrated in Figure II-3.

Figure II-3
Convergence of Industry Change Drivers



(1) Market Drivers

A wider array of DER choices and financing options, and declining DER costs continue to drive increasing customer adoption of solar photovoltaic (PV), electric vehicles, and other DERs.

(2) Policy Drivers

Customer adoption of DERs is also being driven by state and federal policies and incentives, including California's Zero-Emission Vehicle (ZEV) program,[14] tax incentives, and upcoming changes to the Title 24 building standard.[15] The Commission's DRP proceeding has also introduced new requirements for integrating DERs into the California investor-owned utilities' (IOUs')[16] distribution planning processes.[17]

(3) Technology Drivers

There are three key technology factors driving SCE's grid modernization: newly available technologies that will improve safety, reliability and wildfire resiliency; enhanced cybersecurity technologies will address evolving cybersecurity threats; and some existing SCE systems (such as DMS and NetComm) have become obsolete and require wholesale replacement.

(4) Operating Complexity

New requirements for integrating DERs and technological improvements increase the complexity and difficulty of planning and operating the grid infrastructure. Challenges can include: (1) mismatches between peak generation and peak load; (2) masked load, reverse power flows, and power output fluctuations[18] that challenge grid operators in performing their primary role of maintaining grid safety and reliability; and (3) exceeding thermal, voltage, and other operating issues[19] on specific circuit segments—which are often not visible to system operators using existing telemetry and operating tools.

---

[14] The ZEV program is part of the California Air Resources Board's (CARB's) Advanced Clean Cars package of coordinated standards that controls smog-causing pollutants and GHG emissions of passenger vehicles in California. This program requires auto manufacturers to offer specific numbers of battery-electric, hydrogen fuel cell, and plug-in hybrid electric vehicles, calculated as a function of their total vehicle sales and vehicle types; the more electric driving range a vehicle has, the more credit it receives.

[15] Title 24 building energy efficiency standards are designed to reduce wasteful, uneconomic, inefficient or unnecessary consumption of energy, and enhance outdoor and indoor environmental quality. These standards are updated every three years. The 2019 standards, which take effect January 1, 2020, require that all new homes include solar PV systems. The systems shall be sized to meet the home's annual electricity needs.

[16] The IOUs include SCE, Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E).

[17] *See* D.17-09-026 and D.18-02-004 in R.14-08-013.

[18] D.18-03-023 Appendix C Section E. pg. 7 "Distributed generation resources may be randomly intermittent, such as a cloud covering a solar panel. This intermittency causes voltage fluctuations and as a consequence, potential flicker."

[19] Resolution E-4982, Attachment B, Section F provides a list of 11 potential system/integration challenges.

b) Capabilities

Due to these changes taking place within the utility industry, SCE is augmenting its capabilities for electric system planning and grid operations. This will enable SCE to continue providing safe and reliable service while also meeting the evolving expectations of our customers. These capabilities are organized into five categories.

(1) Engineering and Planning

Engineering and planning (E&P) capabilities help to integrate DERs into SCE's electric system planning processes through more granular DER and load forecasting, sophisticated power flow modeling to identify potential grid needs, and streamlined interconnections of customer DERs. SCE is implementing six high-level capabilities for E&P.

(a) Electrical Network Modeling

SCE is developing an electric grid model that will serve as the single, centralized source of connectivity for all structural and electrical equipment—from the point of electricity generation down to the customer meter. The model will provide a foundational data structure that combines all relevant grid asset attributes and will be updated automatically when grid changes occur. This will provide an accurate representation of the electrical hierarchy and connectivity, which will enhance the data integrity and improve the functions and results of the consuming applications for grid planning as well as grid management and operations.

(b) Load and DER Forecasting

SCE will migrate from its traditional single point-based system forecasting approach to a profile approach for both load and DER forecasting. The traditional forecasting approach consists of identifying a single point-in-time during the year when system load is highest, and then forecasting the growth in peak load over the forecasting period. Under the annual, hour-based profile forecasting approach, annual load profiles with 8,760 data points (one for each hour in the year) are generated using historical grid data. The load growth is then forecasted for each of these data points for each year in the forecasting period.

(c) Engineering Analysis

SCE is enhancing its ability to analyze the electric system and perform annual, hour-based power system analysis. This analysis identifies the grid needs and capacity of discrete distribution circuit segments[20] to receive additional DERs without triggering distribution circuit upgrades. SCE is also augmenting its ability to assess the potential value DERs can provide to specific locations[21] on the distribution system. The DRP requires both of these capabilities.[22]

(d) Project Portfolio Management

SCE is enhancing its annual grid planning processes to identify the grid need projects and consider DERs as potential alternatives[23] for traditional grid infrastructure upgrades. This includes augmenting its project identification and scenario analysis capabilities so that SCE pursues projects that are risk-informed. The modified process helps to ensure sufficient resources are available to support projects from initiation to completion.

(e) Grid Needs Assessment (GNA)

SCE is enhancing its ability to identify its grid needs over a five-year forecasting horizon for four distribution services—distribution capacity, voltage support, reliability, and resiliency. This assessment is modeled based on long-term, profile-based load and DER forecasting. The results of these assessments will be included in the annual GNA filing, as required by the DRP.[24]

(f) DER Interconnection

SCE is streamlining the process and associated software tool for interconnecting customer DERs and load. This should reduce the process duration for interconnecting customer resources and load.

(2) Communications

Communications and cybersecurity enable the GMS to communicate securely with DERs and field devices – at a speed and bandwidth that support current and future monitoring and control requirements. This high-level capability includes field area communications to SCE's field devices and certain large DERs. It also includes the wide-area communications between SCE's substations and central IT systems.

---

[20] Referred to as Integration Capacity Analysis (ICA).

[21] Referred to as Locational Net Benefit Analysis (LNBA).

[22] *See* D.17-09-026, OP 4-19, pp. 58-64.

[23] This is referring the Distribution Investment Deferral Framework (DIDF) discussed later in this testimony.

[24] *See* D.18-03-023, OP 7-8, p. 36.

(3) Grid Management

Grid Management improves grid operators' ability to monitor grid conditions in real-time and control field devices remotely, thereby improving safety, reliability, operational efficiency, and DER integration. SCE is implementing the following four high-level capabilities for Grid Management.

(a) Advanced Distribution and Outage Management

Advanced distribution and outage management includes high-resolution, real-time situational awareness and distribution network analysis and, integrated electronic switching capabilities that support faster and more informed decision making to both avoid and recover from grid outages. This also provides the foundation for adaptive protection whereby field device settings are adjusted dynamically based on current grid conditions.

(b) Grid Reliability Issue Mitigation Analysis

SCE will be able to identify potential grid conditions and determine the proper course of action to avoid power quality or service interruptions. Following any actual service interruptions, SCE will be capable of assessing in real-time the optimal course of action to restore service to the greatest number of customers as quickly as possible (and without spreading the outage to adjacent circuits).

(c) DER State and Constraint Assessment

SCE will be able to gather real-time information from DERs to assess their current and forecasted status and evaluate their availability to provide grid services. These assessments will partially enable SCE's "DER Grid Services Analysis" capability by identifying available DERs that could potentially be dispatched for reliability purposes. Over the longer term this could also support energy market-related DER optimization and dispatch.

(d) DER Grid Services Analysis

SCE will be able to determine potential DER solutions to mitigate forecasted or actual reliability issues on the distribution system based on SCE's assessment of DER status, constraints and availability to provide grid services.

(4) Automation

SCE's automation improves grid monitoring and control capabilities using real-time telemetry such as voltage, current and power flow direction. Automation improves reliability by reducing outage frequency and restoring customers more quickly following an outage. SCE is implementing two high-level capabilities for Automation.

(a) Grid Data Collection and Awareness

SCE is deploying various distribution automation devices that include sensors to collect measurements of real-time grid conditions. This includes fault and grid disturbance data as well as power measurements at each sensor location. Telemetry may also be deployed on distribution circuits with high DER penetration. These data enable the visualization of the grid provided by the GMS.

(b) Execution of Reliability Issue Mitigations

SCE is deploying advanced automated switches capable of responding to command signals from SCE's GMS to perform switching operations that will either help avoid overloads (or other abnormal grid conditions) or restore customer load following an outage. Some switches are also capable of interrupting faults automatically, helping some customers to avoid an outage entirely.

(5) DER Integration Capacity

DER integration capacity (also referred to as "hosting capacity") ensures that DERs can interconnect with the distribution system without causing overloads to circuits or other distribution equipment. This high-level capability is enabled by upgrades to relevant distribution equipment including conductors, distribution transformers, substation circuit breakers, subtransmission relays, new distribution circuits, and other upgrades.

Table II-3 summarizes the key high-level capabilities for each of the five capability categories.

Table II-3
Grid Modernization Capabilities

Capability Categories	High-level Capabilities
Engineering & Planning Integrates DERs into grid planning processes	a. Enhanced analysis of the grid's capacity to integrate DERs and of the DERs' potential locational net benefits
	b. Load and DER forecasting based on annual hour-based profiles
	c. Grid needs assessment based on annual hour-based profiles
	d. Risk-based distribution project portfolio management
	e. Streamlined DER and load interconnection process
	f. Electrical modeling and analysis of distribution system connectivity and hierarchy
Communications Enables the Grid Management System to communicate securely with DERs and other grid devices	a. Cyber-secure communications between distribution grid devices, substations and operations control centers
Grid Management Enables grid operators to monitor grid conditions in real-time and control field devices remotely	a. Advanced distribution and outage management
	b. Grid reliability issue mitigation analysis
	c. DER state and constraint assessment
	d. DER grid services analysis
Automation Improves grid monitoring and control using real-time telemetry directional power flow data	a. Grid condition data collection and awareness
	b. Automatic execution of grid reliability issue mitigations
DER Integration Capacity Provides sufficient DER integration capacity to avoid circuit or equipment overloads due to DERs	a. Expanded DER integration capacity

c) <u>Benefits</u>

Implementing SCE's planned Grid Modernization capabilities will provide customer benefits in the following six areas.

(1) <u>Safety</u>

Safety is a primary benefit of Grid Modernization. By improving SCE's ability to monitor and respond to real-time conditions on the distribution system, SCE will be able to mitigate potential safety hazards more quickly and reduce customer and workforce exposure to such hazards. Grid modernization will reduce the number of customers impacted by outages, outage frequency, and outage duration. This means all customers – including customers responsible for maintaining the safety, security and health of those living in SCE's service territory – will experience fewer and shorter periods without electric service.

(2) **Reliability**

Maintaining and improving grid reliability is another primary benefit of Grid Modernization. As grid operations continue to increase in complexity with more DERs, Grid Modernization will provide the capabilities necessary to operate the distribution system more flexibly, thereby maintaining reliability. These capabilities will also provide reliability improvements to the worst performing areas of SCE's distribution system.

(3) **Wildfire Resiliency**

Improving grid resiliency is another Grid Modernization objective that has evolved in recent years due to the increasingly persistent threat of wildfires caused by climate change. SCE's Grid Modernization capabilities support SCE's broader resiliency objectives. For example, SCE's GMS will enable SCE to automate the detection of downed energized conductors using data from SCE's smart meters. This will allow SCE to de-energize these circuits more quickly, thereby reducing the potential exposure to safety and wildfire ignition hazards.

(4) **Decarbonization**

Recognizing the serious threats climate change and air pollution pose, California has taken the lead to address these issues through its greenhouse gas (GHG) reduction goals and renewables targets. Grid Modernization will help California achieve its ambitious decarbonization goals by implementing capabilities that support the integration of DERs and enable SCE to use DERs to help defer traditional grid infrastructure investments, including GHG-emitting sources of generation.

(5) **Customer Empowerment**

Customers benefit from a growing array of DER choices and financing options, while declining costs continue to drive increasing customer adoption of solar PV and EVs. SCE supports customer empowerment and choice by developing Grid Modernization capabilities that will streamline and simplify the process for interconnecting solar PV and electric vehicles to the grid. Increasing the transparency of the distribution planning process will also provide more opportunities for DERs to compete to provide grid reliability services traditionally provided by grid infrastructure.

(6) **Economic Efficiency**

Improving the efficient use of available grid resources is another Grid Modernization benefit. By competing with traditional grid infrastructure to provide grid reliability services, DERs could also potentially offer economic savings by deferring or avoiding grid infrastructure upgrades. Over the longer term, higher penetration of DERs offers the potential to increase the utilization of grid infrastructure by encouraging more efficient use of all available energy resources through appropriate price signals.

Table II-4 maps the Grid Modernization categories and capabilities to the six benefit categories.

Table II-4
Grid Modernization Benefit Categories

Capability Categories	High-level Capabilities	Benefit Categories: Safety	Reliability	Wildfire Resiliency	Decarbonization	Customer Empowerment	Economic Efficiency
Engineering & Planning Integrates DERs into grid planning processes	a. Enhanced analysis of the grid's capacity to integrate DERs and of the DERs' potential locational net benefits				✓	✓	✓
	b. Load and DER forecasting based on annual hour-based profiles				✓	✓	✓
	c. Grid needs assessment based on annual hour-based profiles				✓	✓	✓
	d. Risk-based distribution project portfolio management				✓	✓	✓
	e. Streamlined DER interconnection process				✓	✓	
	f. Electrical modeling and analysis of distribution system connectivity and hierarchy	✓	✓	✓	✓	✓	✓
Communications Enables the Grid Management System to communicate securely with DERs and other grid devices	a. Cyber-secure communications between distribution grid devices, substations and operations control centers	✓	✓		✓	✓	✓
Grid Management Enables grid operators to monitor grid conditions in real-time and control field devices remotely	a. Advanced distribution and outage management	✓	✓	✓			
	b. Grid reliability issue mitigation analysis	✓	✓				
	c. DER state and constraint assessment	✓	✓		✓	✓	✓
	d. DER grid services analysis	✓	✓		✓	✓	✓
Automation Improves grid monitoring and control using real-time telemetry directional power flow data	a. Grid condition data collection and awareness	✓	✓		✓	✓	✓
	b. Automatic execution of grid reliability issue mitigations	✓	✓		✓	✓	✓
DER Integration Capacity Provides sufficient DER integration capacity to avoid circuit or equipment overloads due to DERs	a. Expanded DER integration capacity	✓	✓		✓	✓	✓

2. <u>Regulatory Background and Compliance Requirements Driving SCE's Request</u>

The DRP is the Commission proceeding that most directly influences SCE's Grid Modernization program and the funding requested in this GRC showing. This section describes key elements of DRP Track 3: Policy Issues and identifies specific requirements for this GRC.

a) **Sub-track 1: Growth Scenarios**

The Commission's DRP Track 3, Sub-track 1 (Growth Scenarios) and Sub-track 3 (Distribution Investment Deferral Process) decision orders the IOUs to adopt the California Energy Commission's (CEC's) Integrated Energy Policy Report (IEPR) demand and DER forecast as the basis for their distribution planning cycles, beginning with the 2018-2019 planning cycle.[25] To accomplish this, the IOUs must develop and vet disaggregation methods through the Distribution Forecasting Working Group (DFWG) on an annual basis to establish best practices.

b) **Sub-track 2: Grid Modernization**

The Commission's DRP Track 3, Sub-track 2 decision (DRP Decision)[26] and subsequent Resolution E-4982 (Resolution) provide a framework for Grid Modernization Guidance to inform GRC filings.[27] Most notably, the DRP Decision and subsequent Resolution establish (1) "a classification framework to serve as a common vocabulary for grid modernization investments, and terminology to guide the organization and presentation of future GRC filings," and (2) "submission requirements for the grid modernization portion of future GRC requests, including how to justify each request."[28] This guidance informed development of SCE's GMP included in Appendix A. The guidance also informed SCE's approach for justifying its proposed Grid Modernization investments in this showing. Consistent with the DRP Decision, SCE will justify investments that improve safety and reliability using one of two methods: (1) traditional reliability metrics, which the DRP Decision identifies as Option 1; or (2) a lowest cost approach, which the DRP Decision identifies as Option 3.[29] To justify investments driven by DER integration, SCE plans to use Option 3.

c) **Sub-track 3: Distribution Investment Deferral Framework (DIDF)**

The October 21, 2016 Assigned Commissioner's Ruling on Track 3 Issues finalized the scope of Track 3, Sub-track 3 to identify (1) "distribution grid technologies and/or functions that enable greater DER penetration, integration and value maximization…", (2) "[w]hich

---

[25] D.18-02-004, OP 1, pp. 82-89.

[26] D.18-03-023.

[27] D.18-03-023, pp. 10-14; and Resolution E-4982, pp. 21-22 and Attachment A.

[28] D.18-03-023, p. 2.

[29] D.18-03-023, at pp. 22-27. The DRP decision also included an Option 2, which the Commission concluded was infeasible, and an Option 4, which applies to the Integrated Resource Plan (IRP) proceeding.

technologies may be needed on a location-specific basis… and which may be needed system-wide", and (3) "[t]he types of information a utility must provide to justify the necessity or cost-effectiveness of a proposed DER-related grid modernization investment."[30] D.18-02-004 established the Distribution Investment Deferral Framework (DIDF) as California's first permanent marketplace for third party-owned DERs to provide services to the IOUs' distribution grids.[31]

The five E&P tools and GMS collectively support the Commission's vision of deferring traditional wires solutions with DERs via the DIDF. SCE's E&P software tool investments, in conjunction with the GMS, provide the necessary advancements in SCE's ability to identify and predict grid needs, evaluate different traditional wires and DER solutions, publish GNA and DDOR data to the public to support competitive market participation, improve portions of the interconnection process, and provide the real-time operational visibility and control needed to depend on DERs to provide distribution services on-demand.

B. 2018 Decision

1. Comparison of Authorized 2018 to Recorded

Not receiving a final 2018 GRC Decision until the second quarter of 2019 presented several challenges for SCE's Grid Modernization program. Grid Modernization, which was new in SCE's 2018 GRC request, faced substantial rate-recovery uncertainty due to extensive intervenor opposition. While SCE was confident in the prudence and value of its Grid Modernization request, due to the extent of the opposition, SCE was reluctant to assume financial risk by initiating certain program elements. SCE proceeded with some investments prior to the 2018 GRC Decision, but delayed or scaled back others, such as the FAN, GMS, and substation automation. Although the 2018 GRC Decision recognized the merit of the various Grid Modernization investments,[32] it authorized capital expenditures substantially below SCE's requested amounts. This challenge was compounded by the timing of the 2018 GRC Decision, which was issued in May of 2019, after all of 2018 and a share of 2019 work was complete. As a result, there are variances between the authorized and recorded capital expenditures.

---

[30] D.18-03-023, p. 4.

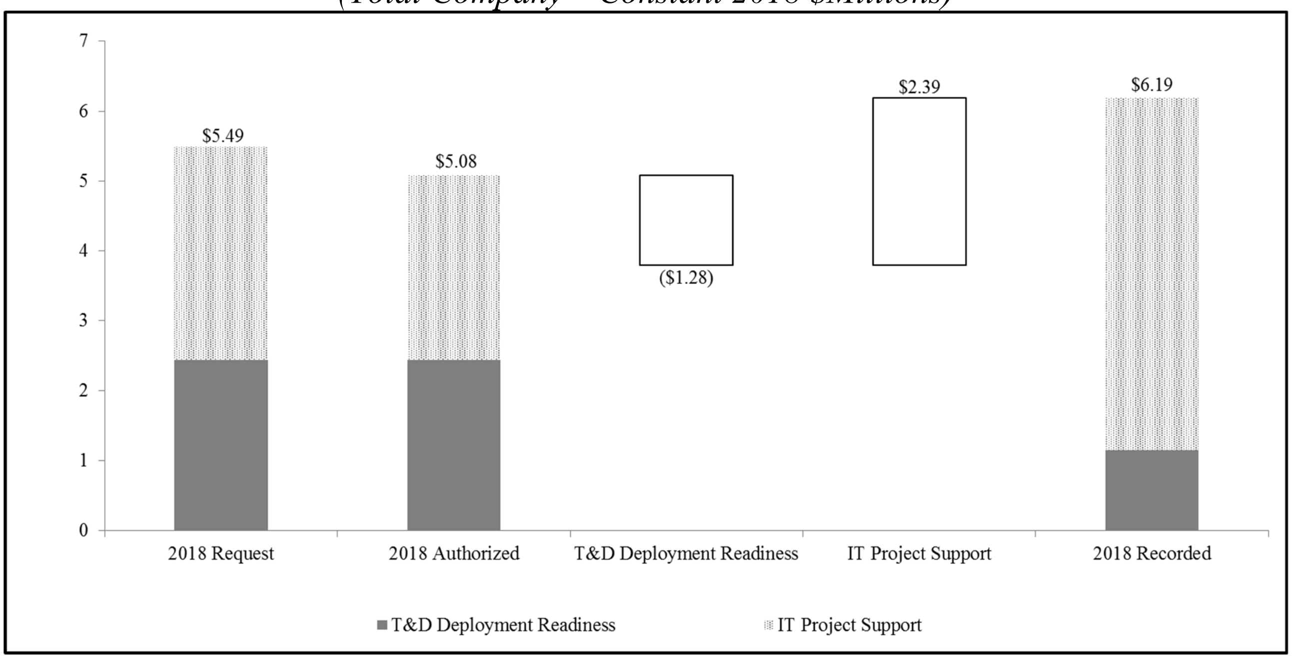
[31] D.18-02-004, OP 2, pp. 83-39.

[32] For example, D.19-05-020, p. 13 states "We find that the FAN is needed now, based on expected cybersecurity benefits and in order to ensure that distribution devices have sufficient communications"; "The GMS will provide cybersecurity benefits, enable DERs, and integrate SCE's distribution software."

Certain elements of the 2018 GRC Decision itself also introduced uncertainty to the Grid Modernization program. For example, the Commission approved the FAN and Common Substation Platform (CSP), but determined that the WAN and Substation Automation-3 (SA-3) are not necessary during the 2018 GRC period.[33] Deploying a CSP at a substation without also deploying WAN would provide no cybersecurity improvements to the substation. WAN expansion is also needed to support the FAN, since it may experience network congestion and data loss. SCE has therefore taken a measured approach to implementing the Commission's guidance at the workstream level.

The 2018 GRC Decision requires SCE to compare the 2018 authorized amounts to the recorded amounts;[34] Figure II-4 and Figure II-5 below compare the authorized and recorded amounts for O&M expenses and capital expenditures.

Figure II-4
Grid Modernization
2018 GRC Authorized Variance Summary 2018 O&M Expenses[35]
(Total Company – Constant 2018 $Millions)

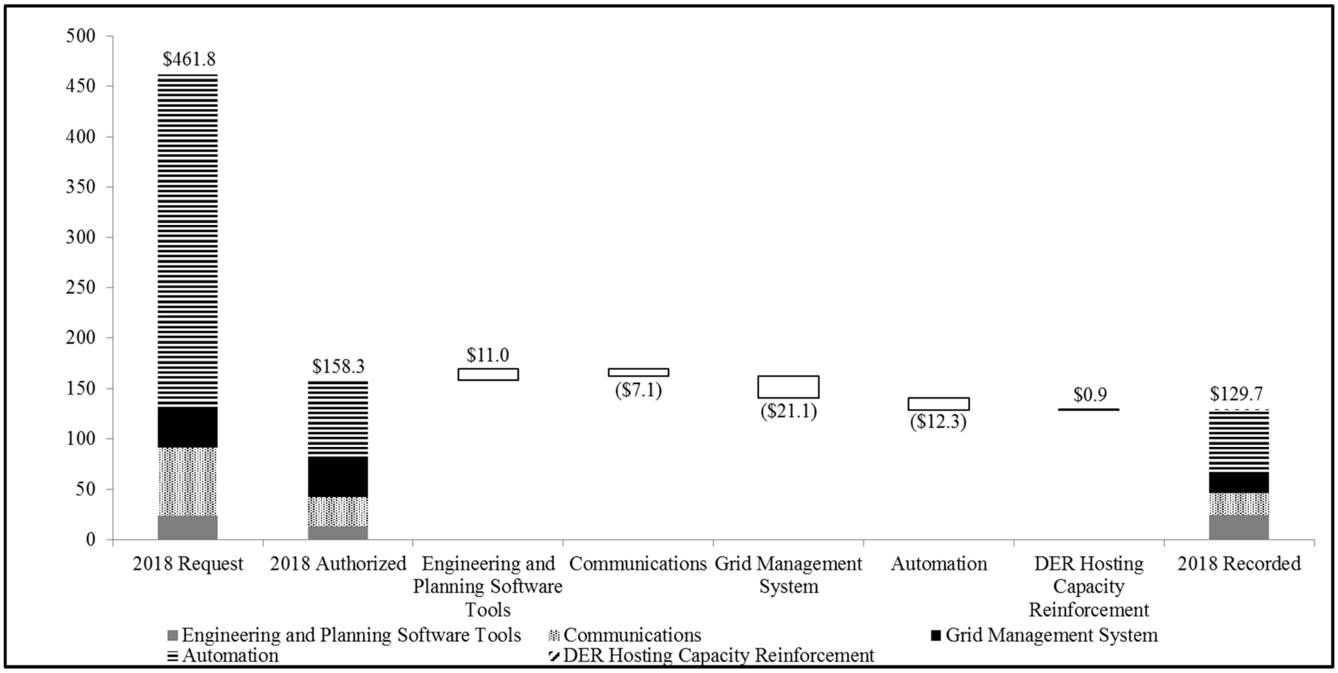


[33] D.19-05-020, p. 13 states with respect to SA-3 that "We find that SCE has not demonstrated the need to proactively update substations at this time" and with respect to WAN that "we do not authorize SCE's proposal for this program because SCE's showing did not demonstrate why WAN expenditures were necessary during this GRC period."

[34] D.19-05-020, OP 22, pp. 441-442.

[35] Please refer to WP SCE-07, Vol. 01. – O&M Authorized to Recorded.

Figure II-5
Grid Modernization
2018 GRC Authorized Variance Summary 2018 Capital Expenditures[36]
(Total Company – Constant 2018 $Millions)



1 **C. <u>O&M Forecast</u>**

2 Table II-5 below shows the recorded and forecast O&M expenses for Grid Modernization.

Table II-5
Grid Modernization O&M
Recorded and Adjusted 2014-2018/Forecast 2019-2021
(Constant 2018 $000)

	Recorded					Forecast		
	2014	2015	2016	2017	2018	2019	2020	2021
Grid Modernization - T&D Deployment Readiness	-	$873	$2,171	$1,162	$1,147	$1,736	$1,540	$1,539
IT Project Support	-	$1,638	$2,168	$4,117	$5,036	$3,766	$5,410	$5,734
Totals	**-**	**$2,511**	**$4,339**	**$5,278**	**$6,183**	**$5,502**	**$6,949**	**$7,272**

[36] Please refer to WP SCE-07, Vol. 01 – Capital Authorized to Recorded.

1. T&D Deployment Readiness

a) Work Description

T&D Deployment Readiness helps to ensure that the T&D organization and its workforce are prepared to implement the new technologies and operations associated with SCE's GMP. This largely consists of organizational change management (OCM), which represents the set of functions that prepare and support employees to successfully adopt the changes associated with deploying new Grid Modernization technologies in order to achieve the desired organizational capabilities. These functions include:

- Understanding business requirements
- Assessing and analyzing potential issues and impacts of the change
- Developing a change management implementation plan and aligning with the project plan
- Designing, facilitating and implementing various interventions to manage the potential pitfalls and minimize the impacts of change
- Aligning leaders and sponsors around a common vision
- Advising, engaging and supporting stakeholders
- Propelling pervasive and relevant communications throughout the organization to effect change
- Implementing, monitoring and tracking project engagement, communications and training plans

Grid operators and planners will need to evolve their capabilities by learning to use new technologies and understand and embrace new processes. This will be accomplished through detailed impact assessments of the organizations deploying, operating, and maintaining the new Grid Modernization technologies. The change impact analysis will result in an OCM plan that focuses on impacted processes and procedures, employee training, identifying and developing needed skill sets, and workforce communications.

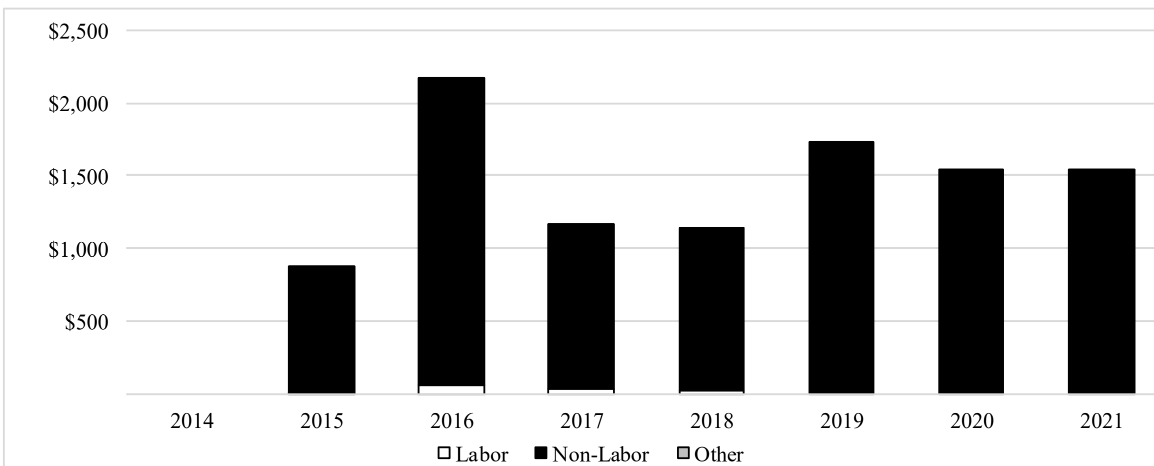
b) Need for Activity

T&D Deployment Readiness is necessary to support the successful implementation of new Grid Modernization technologies such that the organization realizes the desired capabilities and associated benefits, while minimizing the risk that the capabilities are not enabled—or that they are not enabled to their full potential. The transition of an organization to using a new technology is complex. Operators and planners need to evolve their capabilities, learn to use new technology, and embrace new processes. SCE's OCM efforts will help ensure the organization and its employees achieve the capabilities necessary for SCE to realize its vision of a modern grid.

c) Scope and Forecast Analysis

The recorded and forecast O&M expenses for T&D Deployment Readiness are shown below in Figure II-6.

Figure II-6
T&D Deployment Readiness
Recorded and Adjusted 2014-2018/Forecast 2019-2021 [37]
(Constant 2018 $000)



	Recorded					Forecast		
	2014	2015	2016	2017	2018	2019	2020	2021
Labor		$3	$58	$42	$26			
Non-Labor		$869	$2,113	$1,120	$1,121	$1,736	$1,540	$1,539
Other								
Total Expenses		**$873**	**$2,171**	**$1,162**	**$1,147**	**$1,736**	**$1,540**	**$1,539**
Ratio of Labor to Total	-	0%	3%	4%	2%	0%	0%	0%

(1) Historical Variance Analysis

(a) Labor

From 2015 to 2018, labor expenses fluctuated due to variations in SCE lineman inspections necessary to ensure the programmable capacitor controls (PCCs) in the field were compatible and functioning properly to support SCE's Distribution Volt/VAR Control (DVVC)

[37] Please refer to WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A - pp. 3 – 9 – O&M Detail for T&D Deployment Readiness.

deployment. In addition, SCE training to ensure the personnel interacting with Grid Modernization technologies were adequately prepared varied from year to year.

(b) Non-Labor

From 2015 to 2016, non-labor expenses increased by $1.244 million as SCE contracted resources (1) to update substation documentation associated with the DVVC deployment, (2) support Grid Modernization program management governance activities, and (3) help incorporate T&D business processes and operational requirements into the design of IT solutions. Additionally, SCE procured new training materials in 2016. From 2016 to 2017, costs decreased by $993,000 as the need for new DVVC training materials was reduced and IT resources assumed responsibility for developing and documenting technology design requirements. From 2017 to 2018, the non-labor expenses remained flat.

(2) Forecast

(a) Labor

SCE is not forecasting any labor expenses as the lineman inspections necessary to help ensure PCCs in the field are compatible with Grid Modernization hardware have been completed. Additionally, expenses for training activities have transitioned to SCE's T&D Training organization.

(b) Non-Labor

Compared to 2018 recorded, the 2019 non-labor forecast increases by $615,000. Overall, O&M will increase from 2018 to 2019 as contracted OCM work within T&D Deployment Readiness, not including training expenses, is forecasted to increase as the group applies lessons learned from recent deployments. During the 2018 deployments, the lack of resources allocated to identify and communicate "change impacts" slowed the technology deployments. This created a need for additional contracted resources to achieve the forecasted deployment schedules, which have been included in the 2019 forecast. OCM contract expenses remain relatively flat from 2020 onward based on technology deployment schedules being relatively stable from year to year.[38]

In addition to the changes in OCM expenses from 2019 to 2020, there is a decrease of $196,000 mostly due to the 2019 completion of a one-time Value of Service

---

[38] Please refer to workpaper: WP SCE-02, Vol. 04, Pt. 1, Ch. II – Book A - pp. 10 – 11 – T&D Deployment Readiness O&M Workpaper.

(VOS) study[39] to evaluate how much SCE's customers value a customer minute of interruption (CMI).[40] The CMI value is used in the benefit-cost analyses for specific capital workstreams in this Grid Modernization testimony.[41] In addition, whereas in 2018 contract work related to DVVC and OCM activities were charged to T&D Deployment Readiness O&M, in 2019 SCE forecasts that only the contracted OCM activities will continue. The contracted OCM activities within T&D Deployment Readiness will no longer include the training budget forecast since these training activities were transitioned to SCE's T&D Training organization. The supporting testimony, forecasts, and workpapers related to Grid Modernization training are discussed in SCE-06, Volume 3. From 2020 to 2021 the work and forecast remain stable. Details on the forecast are provided in the workpaper.[42]

2. IT Project Support

a) Work Description

IT Project Support includes O&M expenses associated with implementing the E&P software tools, Communications, and GMS capital deployments. This includes the development and delivery of training, IT-related change management, cloud-hosted applications,[43] and employee related expenses.

b) Need for Activity

The Grid Modernization program involves several workstreams with multiple capital projects, all of which are designed to deliver various business capabilities. Each Grid Modernization capital project requires some amount of O&M for activities such as pre-planning, project start-up, business analysis, training, and IT-related change management.[44]

---

[39] SCE commissioned Nexant in 2018 to perform a VOS study with the purpose of estimating the costs customers incur during power outages. This research project was designed to collect detailed outage cost information from SCE's residential, small and medium business, and large commercial and industrial (C&I) customer classes. Please refer to WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A - pp. 12 - 109 – Southern California Edison: 2019 Value of Service Study.

[40] A customer minute of interruption represents a single minute during which a single customer is without electrical service.

[41] Benefit-cost analyses are discussed in the GMS and Automation sections.

[42] Please refer to WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A - pp. 10 - 11 – T&D Deployment Readiness O&M Workpaper.

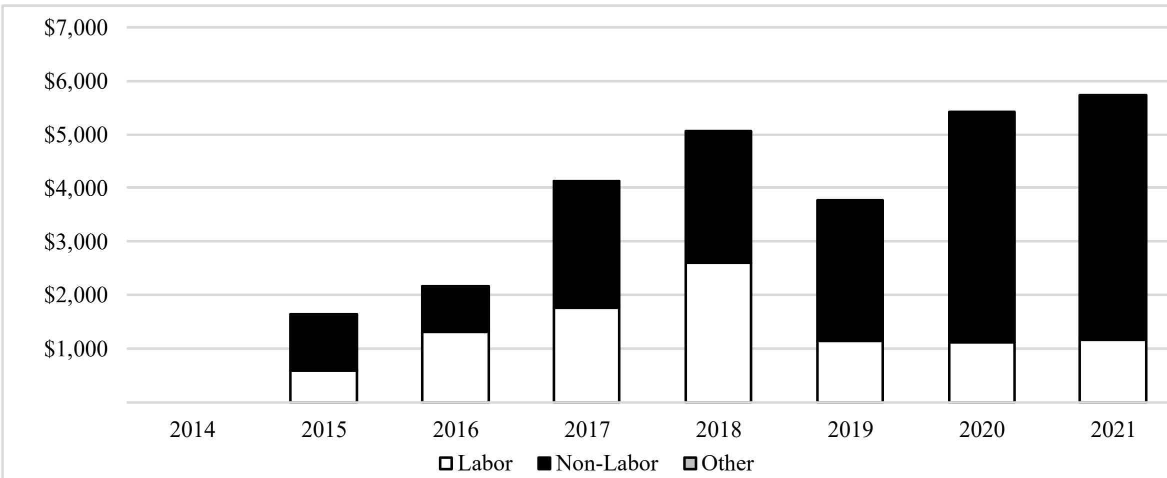
[43] Cloud hosted applications are software as a service (SaaS) solutions that allow users to use the application by accessing it remotely from cloud infrastructure via the internet.

[44] Due to accounting policy, such expenses have to be treated as O&M and not capital.

c) **Scope and Forecast Analysis**

The recorded and forecast O&M expenses for IT Project Support are shown below in Figure II-7.

Figure II-7
IT Project Support[45]
Recorded and Adjusted 2014-2018/Forecast 2019-2021
(Constant 2018 $000)



	Recorded					Forecast		
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Labor		$579	$1,304	$1,754	$2,587	$1,149	$1,112	$1,157
Non-Labor		$1,060	$864	$2,362	$2,442	$2,616	$4,297	$4,577
Other					$6			
Total Expenses		**$1,638**	**$2,168**	**$4,117**	**$5,036**	**$3,766**	**$5,410**	**$5,734**
Ratio of Labor to Total	-	35%	60%	43%	51%	31%	21%	20%

(1) **Historical Variance Analysis**

(a) **Labor**

As shown in Figure II-7, labor expense increased steadily year-over-year between 2015 and 2018. Since the program started in July of 2015, labor expense increased on a monthly basis from $26,000 to over $113,000 in December 2015. Labor expense was incurred during all of 2016 and increased by $450,000 in 2017 due to SCE project staff ramp-up to support the CSP and GMS workstreams and the addition of SCE management and administrative staff in the second half of the year. Labor expense increased by $833,000 in 2018 due to a full year of costs from SCE

[45] Please refer to WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A - pp. 110 – 116 – O&M Detail for IT Project Support.

management and administrative staff and additional engineering support staff from SCE's Power Systems Control (PSC) organization for the GMS.

(b) Non-Labor

Non-labor expense decreased from 2015 to 2016 as SCE deferred E&P-related software, hardware, and training expenditures until 2017 to allow for more detailed analysis of the inter-dependencies across the E&P software tools. From 2016 to 2017, non-labor expense increased as various E&P software tools and the GMS progressed and began incurring expenses for software licensing, hardware maintenance, training, employee travel and other miscellaneous expenses.

(2) Forecast

(a) Labor

As shown in Figure II-7, SCE's recorded labor expenses steadily increased between 2014 and 2018. Starting with SCE's 2018 recorded labor expense as the base, SCE assessed project resource plans for FAN and GMS and expects labor expenses to decrease by $1.438 million from 2018 to 2019 and to remain relatively flat thereafter. SCE forecasts the 2021 labor expense to be $1.157 million for the remaining IT project labor support activities primarily for the FAN and GMS workstreams.

(b) Non-Labor

The forecast IT non-labor expense increases year-over-year from 2019 to 2021 due to the planned expenditures resulting from procurements in all three domains (E&P, Communications, and GMS). The increase of $174,000 from 2018 to 2019 is due to vendor contract costs planned for the Grid Interconnection Processing Tool (GIPT) and GMS workstreams. SCE forecasts an increase of $1.681 million from 2019 to 2020 due primarily to vendor costs for IT-related change management. IT non-labor expenses of $4.57 million for 2021 are based on contractual pricing and negotiations with the selected vendors resulting from competitive solicitations.[46]

D. Capital Expenditures for Grid Modernization

Table II-6 summarizes the 2014–2018 recorded and 2019–2023 forecast capital expenditures for the Grid Modernization investments included in the current chapter. To provide a comprehensive view of the scope of investments within the overall Grid Modernization program, the table also identifies

---

[46] Please refer to WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A - pp. 117 - 118 – IT Project Support O&M Workpaper.

additional Grid Modernization investments included in different sections of testimony. Each investment in this table is consistent with the investment categories listed in the DRP's Grid Modernization Classification Tables.[47]

Table II-6
Grid Modernization Capital Expenditure Summary
Recorded 2014-2018/Forecast 2019-2023
(Total Company - Nominal $000)

	Recorded					Forecast				
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Engineering and Planning Software Tools										
Grid Connectivity Model	$0	$485	$2,173	$4,911	$3,827	$8,417	$6,631	$8,174	$6,193	$4,843
Grid Analytics Applications	$0	$2,705	$5,000	$2,254	$7,853	$6,599	$5,684	$5,827	$6,129	$4,435
Long Term Planning Tool and System Modeling Tool	$0	$978	$4,850	$18,169	$7,813	$7,790	$6,091	$5,650	$2,626	$2,195
Grid Interconnection Processing Tool	$0	$476	$1,172	$1,558	$3,016	$11,489	$5,424	$6,124	$0	$0
DRP External Portal	$0	$478	$1,082	$981	$1,980	$2,057	$1,315	$1,438	$2,780	$2,410
Engineering and Planning Software Tools Total	**$0**	**$5,121**	**$14,276**	**$27,873**	**$24,490**	**$36,352**	**$25,145**	**$27,213**	**$17,727**	**$13,883**
Communications										
Field Area Network	$0	$0	$478	$6,032	$11,823	$6,673	$8,638	$59,128	$72,377	$81,233
Distribution System Efficiency Enhancement Project	$4,518	$4,309	$4,293	$4,846	$5,221	$5,412	$5,532	$5,532	$5,532	$5,532
Common Substation Platform	$0	$0	$180	$1,362	$2,467	$691	$629	$422	$4,149	$4,086
Wide Area Network	$0	$0	$513	$1,241	$1,982	$669	$659	$7,289	$1,983	$1,915
Communications Total	**$4,518**	**$4,309**	**$5,464**	**$13,481**	**$21,493**	**$13,445**	**$15,458**	**$72,371**	**$84,040**	**$92,766**
Grid Management System Total	**$0**	**$0**	**$2,274**	**$7,851**	**$18,726**	**$33,064**	**$35,724**	**$47,611**	**$44,864**	**$30,682**
Automation										
Reliability-driven Distribution Automation	$6,090	$7,141	$10,465	$17,817	$42,011	$61,526	$34,809	$23,872	$25,141	$25,356
DER-driven Distribution Automation	$0	$0	$0	$0	$0	$0	$590	$1,026	$843	$970
Small-scale Deployment	$0	$374	$1,112	$10,207	$3,938	$5,171	$7,633	$7,146	$5,599	$5,326
Reliability-driven Substation Automation*	$0	$248	$8,744	$19,966	$18,131	$6,701	$0	$0	$0	$0
DER-driven Substation Automation	$0	$0	$0	$0	$0	$0	$0	$4,000	$7,828	$5,965
Distribution Volt VAR Control*	SCE has implemented DVVC, which will be migrated to GMS									
Automation Total	**$6,090**	**$7,763**	**$20,321**	**$47,990**	**$64,081**	**$73,398**	**$43,032**	**$36,044**	**$39,411**	**$37,617**
DER Hosting Capacity Reinforcement										
Subtransmission Relay Upgrade Program*	$0	$0	$311	$1,319	$863	$491	$0	$1,488	$0	$0
DER-driven 4 kV Cutovers	Recorded and Forecast Capital Expenditures in SCE-02 Volume 4 Pt. 2 - Load Growth									
DER-driven Substation Transformer Upgrades										
DER-driven DSP Circuits										
DER-driven Circuit Breaker Upgrades										
DER-driven Distribution Circuit Upgrades										
DER Hosting Capacity Reinforcement Total	**$0**	**$0**	**$311**	**$1,319**	**$863**	**$491**	**$0**	**$1,488**	**$0**	**$0**
Cybersecurity	Recorded and Forecast Capital Expenditures in SCE-04 Volume 3 - Cybersecurity									
Energy Storage	Recorded and Forecast Capital Expenditures in SCE-02 Volume 4 Pt. 1 - Energy Storage									
Microgrid Interfaces	There are no recorded or forecasted expenditures within this GRC period									

* SCE performs failure-based equipment replacements in each of these programs, and associated capital funding is requested in other volumes outside of Grid Modernization.

[47] Resolution E-4982, Attachment A, pp. 26-29.

1. Capital Expenditures for Engineering & Planning Software Tools

a) High-level Program Description

In its 2018 GRC testimony, SCE presented the need, vision, and plan to modernize its system planning processes and engineering software tools. In alignment with the Commission's 2018 GRC Decision, SCE remains committed to developing new capabilities to engineer, plan, and operate a modern grid that keeps pace with increasing customer adoption of DERs and California energy and environmental policies while continuing to provide safe, reliable, and resilient electric service.

This commitment has already resulted in successful early-stage implementations of the E&P software tools starting in 2016. These tools support SCE in calculating the amount of DERs that the distribution system can host without triggering distribution infrastructure upgrades, and in forecasting SCE's short-term and long-term grid needs. SCE successfully implemented system-wide Integration Capacity Analysis (ICA) and published the results via SCE's Distributed Energy Resource Interconnection Map (DERiM) in June 2017. In December 2018, SCE successfully replaced DERiM with the Distribution Resources Plan External Portal (DRPEP) to offer enhanced functionality to customers using the results of ICA and other DRP reports—including the GNA and DDOR developed through SCE's annual capacity planning and DIDF process. The Grid Analytics Application (GAA), System Modeling Tool (SMT), and the Long Term Planning Tool (LTPT) forecasting engine directly enabled the development of the 10-year customer load and DER forecast as presented to the 2019 DIDF working group on May 15, 2019. Milestones for GIPT include the successful completion of the proof-of-concept and vendor selection. SCE also delivered the Grid Connectivity Model's (GCM's) as-built distribution model, which contains electrical hierarchy and connectivity information that is foundational to the E&P software tools and GMS.

In the 2021 GRC period, SCE continues to build upon the progress achieved to-date by delivering additional planning capabilities and enhancing those already enabled. E&P retains the same workstream structure established in the 2018 GRC, with one adjustment to combine the SMT and LTPT due to the close inter-dependency of their features and functionalities. In the 2021 GRC, SCE will refer to this combination as LTPT-SMT, although in certain parts of this chapter SCE also refers to the SMT and LTPT components individually when describing their respective contributions to the various capabilities. The E&P workstreams are presented in the following order:

- GCM

- GAA
- LTPT-SMT
- GIPT
- DRPEP

SCE's continued investments in these new E&P software tools will help resolve multiple limitations with SCE's legacy tools.[48] For example, the legacy tools are unable to calculate accurately the amount of DERs that the distribution system can host without triggering traditional electric system upgrades. ICA,[49] which is performed by the SMT, informs potential interconnection applicants about how much DER can be interconnected before triggering facility upgrades.

Similarly, SCE's legacy E&P tools are insufficient for assessing SCE's short-term and long-term grid needs and lack the capacity to analyze the large number of scenarios and other external factors required to accurately assess these grid needs. Once deployed, the LTPT will prepare SCE's 10-year load and DER forecast. It will also be able to identify SCE's short-term and long-term grid needs. The LTPT-SMT, in conjunction with the other E&P software tools, will address integration challenges (e.g., thermal and operational limitations), as described in Resolution E-4982, Attachment B, section F.[50]

Table II-7 summarizes the high-level capabilities that SCE expects the E&P software tools to support.

---

[48] E.g., Master Distribution Interface (MDI) is the legacy software tool for electric system planning.

[49] ICA quantifies the capability of the system to integrate DER within thermal ratings, protection system limits and power quality and safety standards of existing equipment.

[50] Resolution E-4982, Approval of Updates to Grid Modernization Classification Tables, Attachment B, Section F, issued pursuant to Decision (D.) 18-03-023, dated March 28, 2019.

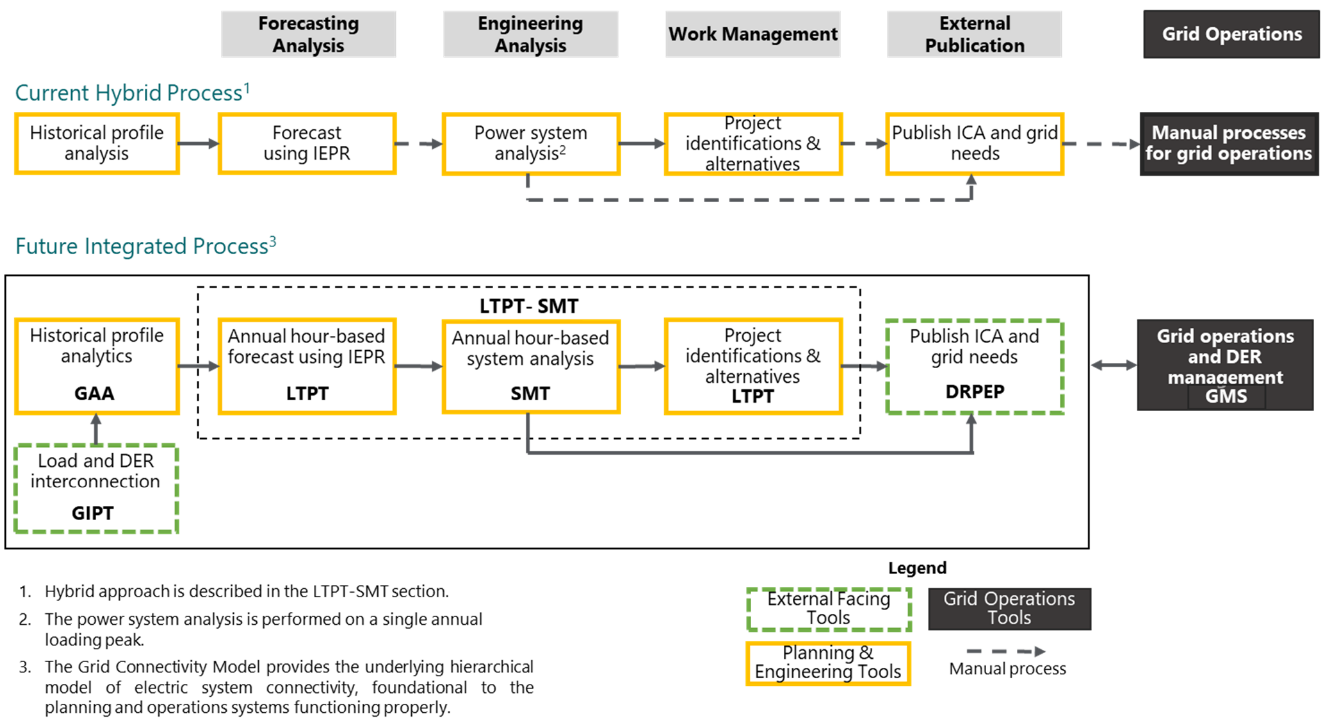
Table II-7
E&P Software Tools-supported Capabilities

Capability Categories	High-level Capabilities
Engineering & Planning Integrates DERs into grid planning processes	a. Enhanced analysis of the grid's capacity to integrate DERs and of the DERs' potential locational net benefits
	b. Load and DER forecasting based on annual hour-based profiles
	c. Grid needs assessment based on annual hour-based profiles
	d. Risk-based distribution project portfolio management
	e. Streamlined DER and load interconnection process
	f. Electrical modeling and analysis of distribution system connectivity and hierarchy

Given the inter-dependencies between the capabilities, SCE has taken an integrated release approach to the E&P software tools that supports sequential as well as parallel implementations. This requires close collaboration for documenting business requirements, prioritizing delivery of functionalities based on business need, and proper resource planning, while reducing impacts to end-users as they transition to the new business processes.

Figure II-8 depicts the relationships between the various planning tools as well as their interaction with SCE's grid operations systems.

Figure II-8
Interaction and Data Integration of Grid Mod Software Tools



b) **Summary of Cost Forecast**

Table II-8 summarizes the E&P software tools capital expenditures recorded for 2014–2018 and forecast for 2019–2023.

Table II-8
Engineering & Planning Software Tools Capital Expenditure Summary
Recorded 2014-2018/Forecast 2019-2023
(Total Company - Nominal $000)

	Recorded					Forecast				
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Grid Connectivity Model		$485	$2,173	$4,911	$3,827	$8,417	$6,631	$8,174	$6,193	$4,843
Grid Analytics Applications		$2,705	$5,000	$2,254	$7,853	$6,599	$5,684	$5,827	$6,129	$4,435
Long Term Planning Tool and System Modeling Tool		$978	$4,850	$18,169	$7,813	$7,790	$6,091	$5,650	$2,626	$2,195
Grid Interconnection Processing Tool		$476	$1,172	$1,558	$3,016	$11,489	$5,424	$6,124		
DRP External Portal		$478	$1,082	$981	$1,980	$2,057	$1,315	$1,438	$2,780	$2,410
Engineering and Planning Software Tools Total		**$5,121**	**$14,276**	**$27,873**	**$24,490**	**$36,352**	**$25,145**	**$27,213**	**$17,727**	**$13,883**

SCE's capital expenditures for the E&P software tools are higher than estimated in the 2018 GRC request. SCE took targeted and necessary steps in proceeding with the E&P software tools to comply with DRP requirements and to obtain a greater understanding of the integration and implementation scope of the various tools. SCE conducted several competitive solicitations to obtain a comprehensive solution for E&P, but the results revealed that no single vendor solution was available. SCE therefore decided to acquire products from multiple vendors and to manage a substantial integration effort, which resulted in higher costs. The scope of this effort includes integrating disparate vendor products, customizing and configuring each product, and operationalizing them within SCE's production environment.

The DRP requirement that the IOUs forecast based on annual, hour-based profiles provides a useful illustration of this integration complexity.[51] The traditional forecasting approach consists of identifying a single point-in-time during the year when system load is highest, and then forecasting the growth in peak load over the forecasting period. Performing forecasting based on annual, hour-based profiles requires generating 8,760 data points (one for each hour in the year) using historical field measurements, including Advanced Metering Infrastructure (AMI) and Supervisory Control and Data Acquisition (SCADA) data. The load growth is then forecasted for the electric system for each year in the forecasting period.

Enabling this forecasting capability requires integrating four software components: the LTPT-SMT, GAA, and GCM. First, GCM provides the electrical connectivity model to the other E&P software tools. In addition, GAA provides historical load and generation profiles to LTPT-SMT, which is only feasible after extensive data mining of customer AMI and SCADA data. The LTPT-SMT then develops the 10-year load and DER forecast and generates the 10-year capacity plan. This is one example of a system planning capability that is not achievable or readily available with any commercial off-the-shelf (COTS) product.

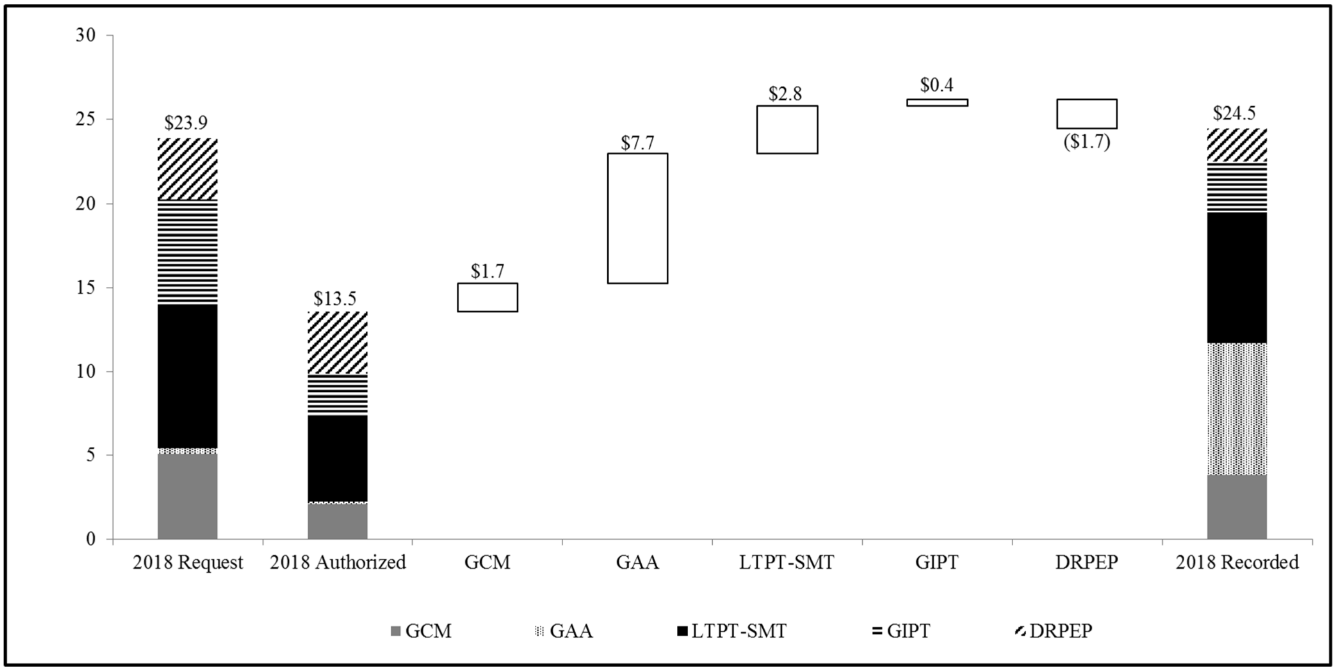
The following sections provide more detailed information about each E&P software tool, including the capabilities they enable, benefits they provide, forecasted capital expenditures, and corresponding cost basis.

c) <u>Comparison of Authorized 2018 to Recorded</u>

Figure II-9 below compares the 2018 authorized amounts to the recorded amounts for the E&P software tools capital expenditures.

[51] D.17-09-026, OP 5.

Figure II-9
Engineering & Planning Software Tools[52]
2018 GRC Authorized Variance Summary 2018 Capital
(Total Company - Constant 2018 $Millions)



As Figure II-9 indicates, the 2018 recorded capital expenditures are higher than the 2018 authorized amount, but they are consistent with the amount requested in the 2018 GRC. This variance is attributed to two factors: (1) the Commission approved only partial funding for E&P despite accepting the justifications for the need,[53] and (2) the complexity in integrating the various E&P software applications is more considerable than originally estimated.

The largest variance pertains to the GAA workstream where, due to the project's schedule shift, $10 million previously planned for 2016 and 2017 was moved to 2018 through 2020. Similarly, for the GCM workstream, $1.7 million originally planned for 2016 and 2017 was shifted to 2018 through 2020. For DRPEP, the 2018 variance was due to an acceleration of project activities in earlier years to ensure DRP compliance with ICA and LNBA requirements.

---

52 Please refer to WP SCE-02, Vol. 2, Pt. 1, Ch. II – Book A - pp. 119 - 120 – Grid Modernization Authorized to Recorded Details.

53 D.19-05-020, p. 157.

d) Need for Capital Program

Market, policy and technology factors drive SCE's need for the capabilities enabled by the E&P software tools. The specific investment drivers and the customer benefits SCE expects to result from these capabilities are summarized below.

(1) Drivers

(a) Market Drivers

A wider array of DER choices and financing options, and declining costs continue to drive increasing customer adoption of solar PV, electric vehicles and other DERs. This higher pace of customer adoption, which is driven by market as well as California and federal policies, is driving SCE's need to augment its grid planning tools and processes to consider DERs—both in terms of their forecasted impact on load and grid needs, and the opportunity for them to help defer traditional grid infrastructure upgrades. The GCM, GAA and LTPT-SMT each perform crucial roles in supporting the integration of DERs into SCE's distribution grid planning and operations. The GCM provides the underlying grid network model to the other E&P tools. The GAA provides the annual, hour-based load and generation profiles to the LTPT-SMT. The LTPT-SMT performs the analysis that informs the ICA and opportunities for DERs to defer traditional grid infrastructure upgrades.

(b) Policy Drivers

The DRP proceeding is the primary policy driver of SCE's E&P software tools. This proceeding has created new requirements for incorporating DERs into SCE's grid planning and operations processes by identifying DER opportunities and sharing this information with the public.

The Commission requires SCE to prepare hosting capacity analysis calculations that rely on annual, hour-based profiles of voltage, load and generation measurements.[54] These calculations are prepared by the LTPT-SMT, which relies on the GCM for the underlying distribution network connectivity model and the GAA for the annual, hour-based profiles. DRPEP is used to publish these calculations to the public monthly.

The Commission also requires SCE to file a GNA report and a DDOR report annually.[55] The GNA must include grid needs identified by the annual planning process

---

[54] D.16-12-036, OP 1.

[55] D.18-02-004, OP 2.j and 2.1, p. 84.

across SCE's distribution and subtransmission systems that fall under the four distribution services (distribution capacity, voltage/VAR support, reliability, and resiliency)[56] adopted by the Decision Addressing Competitive Solicitation Framework and Utility Regulatory Incentive Pilot[57] and subsequent Decision on Track 3 Policy Issues, Sub-Track 1 (Growth Scenarios) and Sub-Track 3 (Distribution Investment and Deferral Process).[58] The GNA and DDOR will be prepared by the LTPT-SMT, which will rely on the GCM for the connectivity data inputs to perform its annual, hour-based power flow and underground cable temperature analyses. Without the GCM, the LTPT-SMT functions would take much longer to complete, and SCE would have to continue with its labor-intensive model creation and validation process. DRPEP is used to publish these reports to the public annually.

The Decision on Track 3 Policy Issues, Sub-track 1 (Growth Scenarios) and Sub-track 3 (Distribution Investment and Deferral Process) orders SCE to publish the annual GNA and DDOR data "in map form, as a pop-up layer atop the circuit models being developed for the ICA, and in downloadable, machine-readable datasets."[59] This decision further orders SCE to develop a central DRP data access portal, by which users can click between tabs to view ICA, LNBA, GNA, and DDOR data on the circuit map, and can query and export data in tabular form based on a geographic search or keyword search.[60] In addition, data portals shall allow users to access data via an API in a functional format from back-end servers.[61] The Administrative Law Judge's Ruling Modifying the DIDF Process also expanded the contents of the GNA and DDOR to include multiple new data elements.[62] As a result, SCE must continue to develop its DRPEP to publish these new data elements.

---

56 D.18-02-004, p. 35, *see* also footnote 15.

57 D.16-12-036, OP 2. pp. 77-78.

58 D.18-02-004.

59 D.18-02-004, OP 2.e., p. 83.

60 D.18-02-004, OP 2.l., p. 85.

61 D.18-02-004, OP 2.l., p. 85. While SCE's existing tools have the ability to publish the ICA and LNBA datasets, the impacts of GNA and DDOR additions and the potential for frequent API calls is unknown. SCE must therefore continue to assess the frequency of API calls along with the volume of data being queried and exported. These frequencies of these activities may burden SCE's existing cloud infrastructure and impact web interface performance for all users. As API demand increases, SCE will therefore either need to upgrade its cloud infrastructure or limit the number of API calls to maintain web application performance.

62 Assigned Commissioner's Ruling, dated May 7, 2019, in R. 14-08-013, Attachment A.

(c) **Technology Drivers**

Several limitations of SCE's legacy software tools drive the need for new E&P software tools. Today, SCE uses multiple disconnected electrical connectivity models to inform grid planning and operations. As the grid becomes increasingly dynamic with the adoption of higher levels of DERs, SCE must migrate to an integrated electrical connectivity model. The GCM will ensure that every system and user performs work from a centralized model that is updated and maintained regularly, improving the consistency and quality of the data and reducing the need to create network models manually for various analyses.

SCE has also traditionally relied on manual data analysis methods due to the vast amounts of electrical and asset data types, sources, and formats that SCE maintains—requiring significant time and resources to access, consolidate, validate and analyze. This approach does not allow SCE personnel to fully utilize SCE's AMI data to support grid analytics. Transitioning to the GAA will provide a technology solution that improves the accuracy and effectiveness of SCE's grid analytics and more fully utilizes available AMI data.

SCE's existing system planning work management process involves various manual processes due to limitations of the existing tool. As DRP requirements increase the complexity of grid planning processes, the risk of error and poor data integrity resulting from manual data manipulation also increases. Deploying the LTPT-SMT toolset reduces this risk by improving data integrity.

There are multiple deficiencies with SCE's current interconnection pilot application and associated processes. Customers must still submit paper or soft copy requests for various interconnection tariffs. SCE cannot validate these handwritten forms automatically, which results in manual processing that lengthens the duration of the process.[63] There are also manual tasks and handoffs throughout the interconnection process. Interconnection information is maintained in multiple disparate databases that can result in system planners not having the most current information about pending or recently-completed interconnections. The existing technology and processes are seemingly inadequate for meeting customer expectations regarding the interconnection process and duration, and they do not support SCE's modernized grid planning processes.

[63] SCE's current DER interconnection process does not track application drop-out and success metrics due to limited digital tracking.

(d) Benefits

(i) Safety

By providing an accurate and integrated electrical connectivity model, the GCM will help ensure that SCE's visualization and grid operations tools provide grid operators with better insight into actual real-time grid conditions. This should result in a more accurate model for informing switching or other grid operations decisions that promote safe grid conditions. The GAA will help ensure that the grid topology and hierarchy in the GCM is accurate, and therefore also helps to provide safety benefits.

(ii) Reliability

By providing an accurate and integrated electrical connectivity model, the GCM will help ensure that SCE's visualization and grid operations tools provide grid operators with better insight into actual real-time grid conditions. This should result in a more accurate model for informing switching decisions to avoid overloads and respond to customer outages. The GAA will help ensure that the grid topology and hierarchy in the GCM is accurate, and therefore also helps to provide reliability benefits.

(iii) Wildfire Resiliency

By providing an accurate integrated electrical connectivity model, the GCM will help ensure that SCE's visualization and grid operations tools provide grid operators with better insight into actual conditions. This would help ensure that SCE is successful in implementing an application within the GMS that automates the detection of downed energized conductors using data from SCE's smart meters. This capability would allow SCE to de-energize these circuits more quickly, thereby reducing the potential exposure to safety and wildfire ignition hazards.

(iv) Decarbonization

The five E&P software tools all help to promote DER adoption, offsetting the need for additional GHG-emitting sources of generation. The GCM provides the accurate, integrated electrical connectivity model needed for SCE's ICA and annual distribution planning process (i.e., DIDF) that helps identify opportunities for DERs to potentially defer traditional grid infrastructure investments. The GAA develops the annual, hour-based load and DER profiles used for the ICA and DIDF processes. The LTPT-SMT performs SCE's grid planning analytical processes, helping to ensure that DERs are considered as potential alternatives to traditional grid infrastructure upgrades. The DRPEP provides information to the public regarding opportunities for DERs to defer traditional grid infrastructure investments. DRPEP also provides customers with more detailed, up-to-date[64] information about the ability of distribution circuits to receive additional DERs. The reduced uncertainty in the inquiry process and shorter interconnection processing times and costs should promote further DER growth, which would displace the need for incremental generation resources that produce GHG emissions.

The GIPT offers customers the ability to connect their DER projects to the grid more quickly and efficiently. The greater ease and transparency of the interconnection process should also support higher customer adoption of DERs, which can displace the need for incremental generation resources that produce GHG emissions.

(v) Customer Empowerment

The five E&P software tools all help to empower customers with a greater number of clean energy choices. As described in the preceding Decarbonization section, the GCM, GAA, and LTPT-SMT help to identify circuit locations with available capacity to interconnect DERs. They also identify opportunities for DERs to defer traditional infrastructure upgrades. This provides more options for customers to interconnect DERs.

Likewise, the DRPEP has provided increased transparency of SCE's hosting capacity by providing timely publications of the ICA, LNBA, GNA and DDOR, and supporting data download, integration and analysis. Customers benefit from more timely and accurate information through reduced uncertainty in the inquiry process, and shorter interconnection processing times and costs through the use of ICA.

The GIPT is intended to improve the overall customer experience throughout the interconnection project lifecycle by increasing the transparency and convenience of the application process, providing a higher certainty of interconnection viability, and accelerating interconnection-request turn-around times.

(vi) Economic Efficiency

The E&P software tools may help to reduce costs by identifying opportunities for DERs to potentially defer traditional grid infrastructure investments. The GCM provides the accurate integrated electrical connectivity model to the GAA, which prepares the annual, hour-based load and generation profiles. The LTPT-SMT performs the power system analysis

---

[64] This refers to ICA values that are updated and published monthly.

that identifies the potential DER opportunities to defer traditional grid infrastructure upgrades. The DRPEP publishes these potential capital deferral opportunities externally. To the extent that a DER provides a lower cost alternative to a traditional grid infrastructure upgrade, the cost to resolve a forecasted grid need may be reduced.

Increasing the granularity of SCE's system planning analysis capabilities will also enable SCE to analyze and validate projects driven by planning and forecasting assumptions, which could better define SCE's forecasted grid needs. This has the potential to increase the accuracy of the timing and sizing of infrastructure projects—whether they include traditional grid infrastructure or DERs.

e) Grid Connectivity Model (GCM)

(1) Program Description

The GCM is a software model of SCE's entire electrical grid. This model replaces multiple disconnected models and will serve as the single, centralized source of connectivity for all structural and electrical equipment—from bulk generation resources down to the customer meters. The GCM is a foundational data structure that combines all relevant grid asset attributes. To help ensure that it continues to accurately reflect the grid over time, the GCM is updated automatically when grid changes occur by receiving near real-time information from various operational, asset, and geographic information systems. The primary objective of GCM is to provide an accurate representation of the electrical hierarchy[65] and connectivity while supporting enhanced capabilities of other E&P tools and the GMS.[66]

Table II-9 identifies in shading the one high-level E&P capability supported by the GCM.

---

[65] Electrical hierarchy refers to the relationship between the various electrically-connected components of the electrical system. For example, the GCM will identify the connection between customer meters to distribution circuits and to substations.

[66] The GCM will support many tools and systems, including: planning tools, analytical systems, and operational systems such as the GMS.

Table II-9
GCM-supported Capability

Capability Categories	High-level Capabilities
Engineering & Planning Integrates DERs into grid planning processes	a. Enhanced analysis of the grid's capacity to integrate DERs and of the DERs' potential locational net benefits
	b. Load and DER forecasting based on annual hour-based profiles
	c. Grid needs assessment based on annual hour-based profiles
	d. Risk-based distribution project portfolio management
	e. Streamlined DER and load interconnection process
	f. Electrical modeling and analysis of distribution system connectivity and hierarchy

The GCM represents a model of electrical devices and structural components connected by conductors. The model considers various device statuses and electrical characteristics to represent the network. The GCM obtains data from various systems of record to complete the model. These systems contain operational, geo-spatial, connectivity, and asset information. The intent of GCM is to provide uniformity in the flow and use of data across grid planning and operations, ensuring that all users obtain data from a single, reliable system model.

Grid connectivity information has historically been scattered across multiple systems. SCE has used a legacy system to maintain the electrical connectivity model for the schematic view of the distribution circuits. System operators use the distribution connectivity model in the OMS for managing and determining the extent of outages. Customer Service uses the relationship between distribution assets and customer meters in the Customer Service System (CSS) and information from OMS to identify the customers impacted by an outage. In addition to grid connectivity information being located across multiple systems, business processes vary across these datasets, automated synchronization of datasets is limited, and, in some cases, data is inconsistent or incomplete across the datasets.

To create a model out of data sourced from multiple systems, each location within the electrical system needs to be unified through a system-wide connectivity model. The GCM creates a model that is agnostic to any vendor-specific format, eliminating the need for conversion between platforms. The GCM ensures that every system and user—from the bulk generator to the customer premises—performs work from a centralized model that is updated and maintained regularly, improving the consistency and quality of the data and reducing the need to create network models manually for various analyses. The GCM will provide the connectivity information to the rest of the enterprise using industry standards such as Common Information Model (CIM),[67] eliminating the need to develop custom interfaces for each new system.

The GCM is comprised of two elements: (1) the electrical connectivity model and (2) the structural connectivity model. The electrical connectivity model provides various business capabilities including circuit tracing, simulation, topology of the entire grid, connectivity attributes, circuit schematic diagram generation, and a geographic view. The structural connectivity model represents various structures located overhead[68] and underground.[69] The structural connectivity model will include physical attributes such as the length of conductor, segment impedance calculations, availability of underground ducts, and location of electrical assets. The GCM will also contain information about DERs collected from the GIPT. Once fully implemented, the GCM will model both grid-connected and behind-the-meter DERs with their interconnection information[70] in the overall connectivity model.

SCE has successfully implemented the initial release of GCM, which directly supported SCE's ability to perform the ICA. The GCM provided the SMT with the as-built connectivity model and field device setting information for capacitor banks and automatic reclosers. The GCM also provided additional key data such as transformer limits, substation bus bar limits, and DER information. In the 2021 GRC period, SCE plans to continue implementing the remaining GCM capabilities such as completing electrical and structural connectivity, enabling asset attributes and providing model types,[71] as well as accommodating additional scope to support the needs of the Customer Service Re-Platform (CSRP)[72] initiative.

---

[67] Common Information Model (CIM) refers to a standard developed by the electric power industry which aims to allow utility application software to exchange information about an electrical network by establishing a common vocabulary about the electrical network. This standard has been officially adopted by the International Electrotechnical Commission (IEC).

[68] E.g., poles, towers.

[69] E.g., vaults, cable ducts.

[70] E.g., generating capacity, technology, contractual parameters.

[71] Examples include as-planned system model, as-operated system model, etc.

[72] Refer to SCE-03 Vol.03.

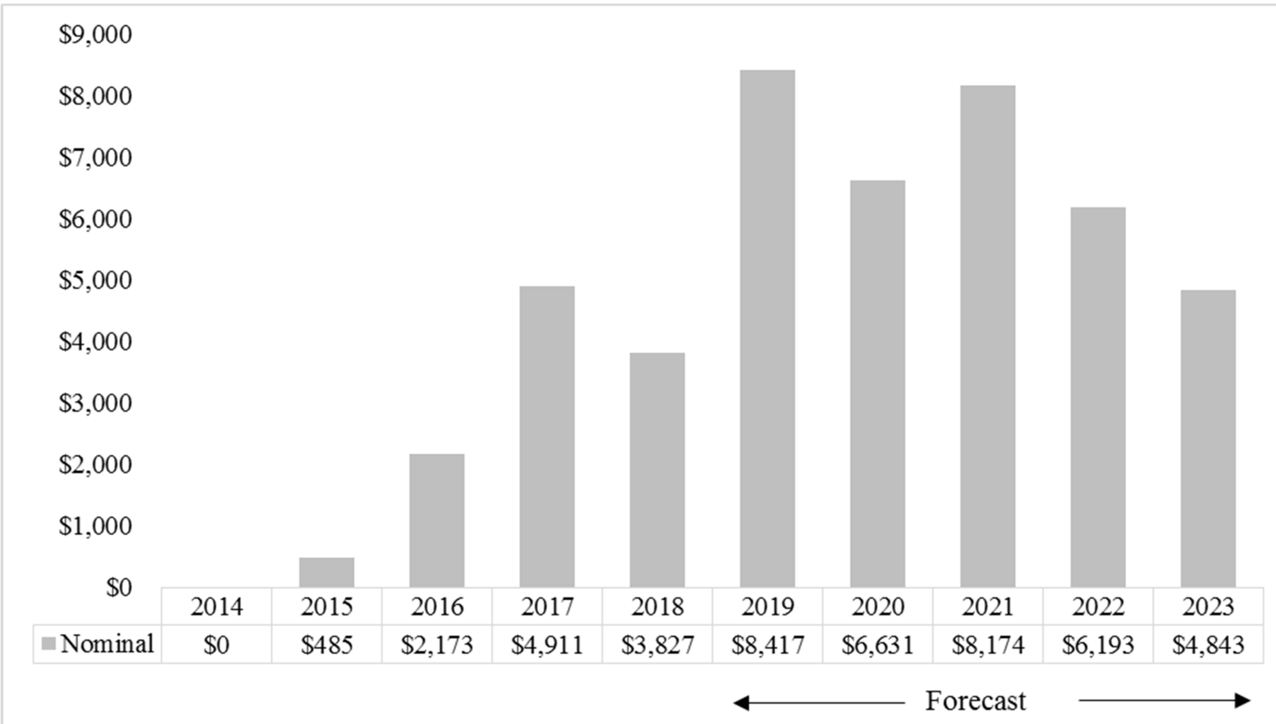
In its 2018 GRC testimony, SCE described alternatives it considered before deciding to pursue the GCM. SCE considered procuring a COTS solution to meet the needs of the GCM project. SCE did not pursue this option because there was no commercially-available product that could comprehensively address SCE's needs. The market was insufficiently mature to provide a commercial product that could cover the multiple perspectives of the electrical network. SCE also considered not pursuing the GCM and continuing to use existing grid connectivity information stored across multiple disparate software solutions. SCE did not pursue this option because it would not provide the various business capabilities that SCE's system planners and system operators need to perform their jobs effectively in a complex operating environment with higher amounts of DERs.[73]

Figure II-10 summarizes the 2014–2018 recorded and 2019–2023 forecast capital expenditures for GCM.

---

[73] E.g., The complexity of distribution power flow analysis to perform system planning and, investigate the DER effects on the grid; perform real-time analysis to address the grid events.

Figure II-10
2014 – 2018 Recorded/2019-2023 Forecast Capital Expenditures for Grid Connectivity Model[74]
CWBS Element CIT-00-OP-NS-000521
(Total Company - Nominal $000)



	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Nominal	$0	$485	$2,173	$4,911	$3,827	$8,417	$6,631	$8,174	$6,193	$4,843

(2) <u>Basis for Capital Expenditure Forecast</u>

SCE based the capital expenditure forecast for GCM on the scope organized around two tracks: (1) the Core Track and (2) the Release Track. The Core Track costs relate to the development of the GCM architecture and the implementation of the new services-based platform. The costs for the Release Track include the custom development and system integration of specific capabilities required for each E&P release from 2019 to 2023. The capital forecast includes project team costs for SCE employees, supplemental workers, consultants, and vendor costs from the preferred Managed Service Provider (MSP) vendor using pre-negotiated labor rates. Please refer to the workpaper[75] for more detail.

---

[74] Please refer to WP SCE-02, Vol. 02, Pt. 1, Ch. II – Book A - pp. 121 – 122 – Capital Details by WBS for GCM.

[75] Please refer to WP SCE-02, Vol. 04, Pt. 1, Ch. II - Book A - pp. 123 – 124 – GCM Capital Workpaper.

f) Grid Analytics Application (GAA)

(1) Program Description

The GAA provides SCE engineers, system planners, and system operators with improved analytical, visualization, and decision-support capabilities required to plan and operate a modern grid. Investment in the GAA is necessary because annual, hour-based profile data and analytics are foundational for capturing the increasingly dynamic grid topology and power flows brought by higher amounts of DERs. The GAA enables key capabilities that SCE needs, such as the ability to perform analytics on large data sources including smart meter data, outage data, and electrical network field measurement data. Moreover, the GAA will support profile-based, long-term and short-term forecasting; visualization of historical load, voltage and outages trends; assessment of equipment health; and circuit model validation. These applications will help optimize planning and support operations, contributing to the safety and reliability of an increasingly dynamic grid with higher amounts of DERs. The GAA also supports development of cleansed profiles[76] and aggregated customer data to produce the monthly ICA calculations. To ensure data consistency, the same profiles prepared for planning and forecasting will also be used for ICA. Furthermore, using the aggregated customer meter data from GAA for the ICA calculations provides a more granular allocation of loads for the analysis.

Table II-10 identifies in shading the four high-level E&P capabilities supported by the GAA.

Table II-10
GAA-supported Capabilities

Capability Categories	High-level Capabilities
Engineering & Planning Integrates DERs into grid planning processes	a. Enhanced analysis of the grid's capacity to integrate DERs and of the DERs' potential locational net benefits
	b. Load and DER forecasting based on annual hour-based profiles
	c. Grid needs assessment based on annual hour-based profiles
	d. Risk-based distribution project portfolio management
	e. Streamlined DER and load interconnection process
	f. Electrical modeling and analysis of distribution system connectivity and hierarchy

76 Cleansing the historical hourly profiles consists of performing automatic adjustments to eliminate any irregularities that distort the profiles.

In 2018, the initial release of GAA successfully implemented the annual, hour-based profile processing platform necessary for long-term forecasting in LTPT. This implementation included an automatic cleansing process to eliminate features in the data that could mislead the forecasting engine, such as load transfers and spikes. In addition, the GAA also enabled a manual profile editing feature to provide a mechanism for correcting potential irregularities in the profile that may result in an inaccurate forecast missed by the automatic process.

In the 2021 GRC period, SCE will build upon the work completed to-date by continuing a phased implementation of GAA. This will include implementing weather data analytics to enhance the potential temperature differences between circuits in different elevations and climate zones. In addition, GAA will enable processing of metered load and generation information, which will support various applications requiring in-depth analysis of historical energy flows on specific distribution circuits. The meter measurements will then be aggregated to pre-identified points of interest[77] to produce virtual annual, hour-based profiles of load or generation at those points of interest. Aggregated customer data will then be used to determine the Transformer Loading Percentage (TLP) at every overhead or underground structure. SCE will also implement advanced methods for systematically updating connectivity information, enabled by historical profile data[78] from GAA. This form of validation will address the Transformer-to-Meter Association (TMA) which helps correctly link a customer meter to its transformer within the GCM. Similarly, phase discovery analytics[79] will help identify incorrect electrical phase connections within the system model. Both capabilities will facilitate identification of inaccuracies in the system model used for system planning and grid operations.

In its 2018 GRC testimony, SCE described how it considered not pursuing GAA and continuing to use existing manual data analysis methods for grid planning and operations. SCE did not pursue this option due to the vast amounts of electrical and asset data types, sources, and formats that SCE maintains, which require significant time and resources to access, consolidate, validate and analyze. This approach would not allow SCE personnel to fully utilize SCE's AMI data to support grid analytics.

---

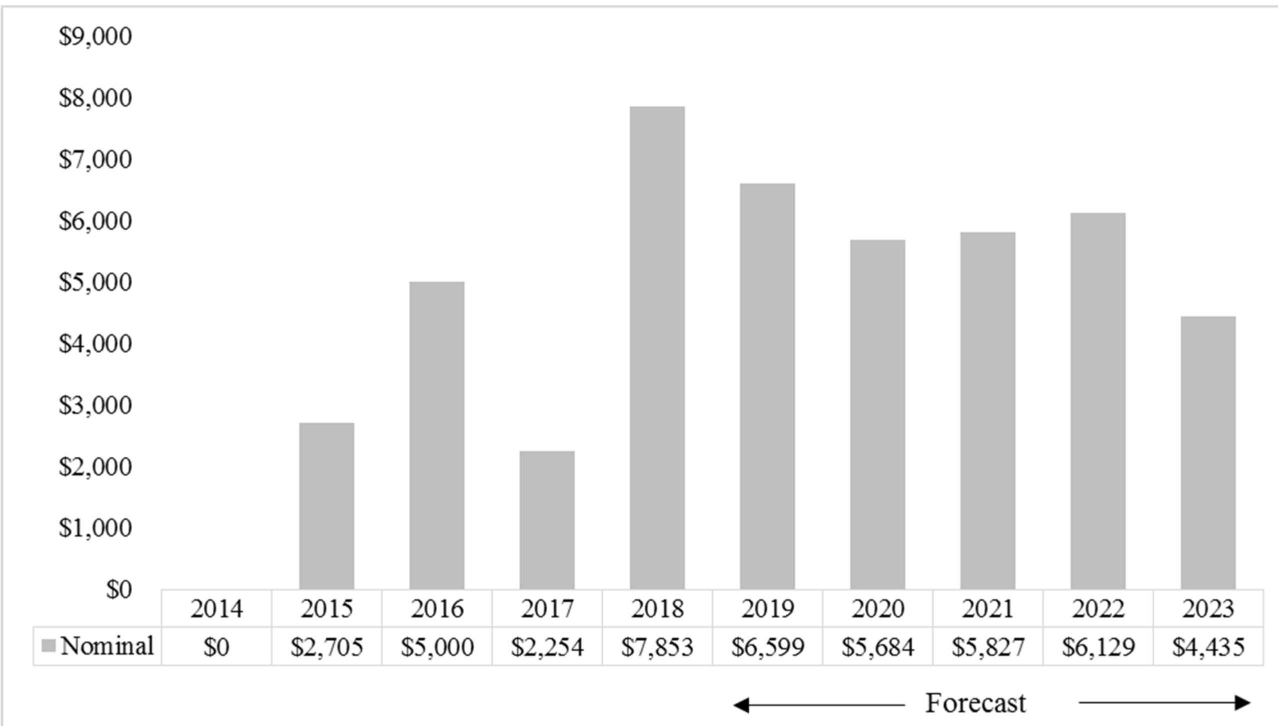
[77] E.g., Service transformers, switches, etc.

[78] This historical data includes the voltage profiles.

[79] Phase discovery analytics helps to identify which power phase (A, B or C) a customer is connected to.

Figure II-11 summarizes the 2014–2018 recorded and 2019–2023 forecast capital expenditures for GAA.

Figure II-11
2014 – 2018 Recorded / 2019-2023 Forecast Capital Expenditures for Grid Analytics Application (GAA)
CWBS Element CIT-00-SD-PM-000247[80]
(Total Company - Nominal $000)



(2) <u>Basis for Capital Expenditure Forecast</u>

SCE derived the capital expenditure forecast for GAA based on the scope of each E&P release from 2019 to 2023. As a key supporting workstream, GAA will deploy 35 software components for analytics, 15 components for data conversion, multiple interfaces, and 5 years of historical datasets. The GAA costs consist of custom software configurations by the selected vendor, data and system integration, testing, and software licensing—all of which were derived from competitive bid solicitations followed by preferred vendor selections. The GAA capital forecast includes

[80] Please refer to WP SCE-02, Vol. 2, Pt. 1, Ch. II, Book A - pp. 125 – 126 – Capital Details by WBS for GAA.

project team costs for SCE employees, supplemental workers, consultants, software, hardware, and selected vendor costs.[81]

g) Long-term Planning Tool (LTPT) and System Modeling Tool (SMT)

(1) Program Description

The LTPT-SMT[82] toolset provides forecasting, power system analysis and work management capabilities that enhance SCE's ability to create ICA results and identify, prioritize, and track risk-informed, optimal grid solutions for SCE's short-term and long-term grid needs. As illustrated in Figure II-8, LTPT generates SCE's annual capacity plans[83] including the GNA, DDOR, and LNBA, which help SCE identify optimal grid solutions. SMT's power flow engine consumes the forecast generated by LTPT and performs ICA and other detailed power system analysis.

From 2016 to 2018, SCE prioritized completing the initial SMT releases that enabled the creation of the ICA and publishing the results to its customers via DRPEP. SCE also completed a comprehensive competitive solicitation for LTPT, made a final product selection following several vendor pilot demonstration workshops, and implemented the current hybrid forecasting approach.[84]

In the 2021 GRC period, SCE plans to accelerate the deployment of several capabilities, including integration of additional internal and external planning inputs[85] into forecasting analysis, enabling profile-based power system analysis, integrating ICA with forecasting analysis to inform system planning, implementing project mitigation and alternative analysis, and project portfolio management.

Table II-11 identifies in shading the four high-level E&P capabilities supported by LTPT-SMT.

---

[81] Please refer to WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A - pp. 127 – 128 – GAA Capital Workpaper.

[82] SMT and LTPT were presented as individual workstreams in the 2018 GRC, but have been combined as LTPT-SMT in the 2021 GRC since functions related to both tools have become integrated, leading to one system analysis and planning engine.

[83] This refers to SCE's distribution and subtransmission planning process described in SCE-02 Vol 4, Part 2.

[84] The hybrid approach is an interim business process that combines new Grid Modernization solutions with legacy systems to complete SCE's annual capacity planning until existing planning tools are retired.

[85] Additional inputs accounting for climate change and planning scenarios which represent a set of possible futures.

Table II-11
LTPT-SMT-supported Capabilities

Capability Categories	High-level Capabilities
Engineering & Planning Integrates DERs into grid planning processes	a. Enhanced analysis of the grid's capacity to integrate DERs and of the DERs' potential locational net benefits
	b. Load and DER forecasting based on annual hour-based profiles
	c. Grid needs assessment based on annual hour-based profiles
	d. Risk-based distribution project portfolio management
	e. Streamlined DER and load interconnection process
	f. Electrical modeling and analysis of distribution system connectivity and hierarchy

The LTPT-SMT-generated ICA informs potential interconnection applicants about how much load and DER can be interconnected on specific circuit segments—throughout SCE's entire distribution system—before triggering facility upgrades. SCE performs this analysis on a monthly basis and publishes it externally on DRPEP. This information supports accurate customer assessments of DER siting opportunities.

The LTPT-SMT will support SCE's annual load and DER forecast planning cycles by incorporating advanced techniques for cleansing load and DER profiles, localized weather data, econometric indicators, and other inputs. In contrast to the historical forecasting method that relied on a single, annual loading peak, LTPT-SMT forecasts annual load and generation profiles with measurements for each hour in the year. This method provides more robust and granular forecasts.

The LTPT-SMT will produce the long-term, profile-based load and DER forecasts which will be used to model SCE's grid needs over a 10-year forecasting horizon for four services: system capacity, voltage support, reliability and resiliency. SCE will use the results of this modeling for the GNA, which SCE is required to file annually.[86]

LTPT-SMT's project analysis capabilities will help engineers and system planners understand the tradeoffs between potential traditional infrastructure upgrades and DER alternatives for addressing grid needs. This should help ensure that optimal project alternatives are

[86] D.18-02-004, OP 2.j. and 2.1, p. 84.

selected as the proposed solutions and included in SCE's DDOR filings, which SCE is required to file annually.[87] LTPT-SMT's project analysis capabilities will also assist with contingency planning for potential failures of selected DER bidders to meet interconnection milestones. This contingency planning is necessary to avoid exposing the system to potential reliability risks.

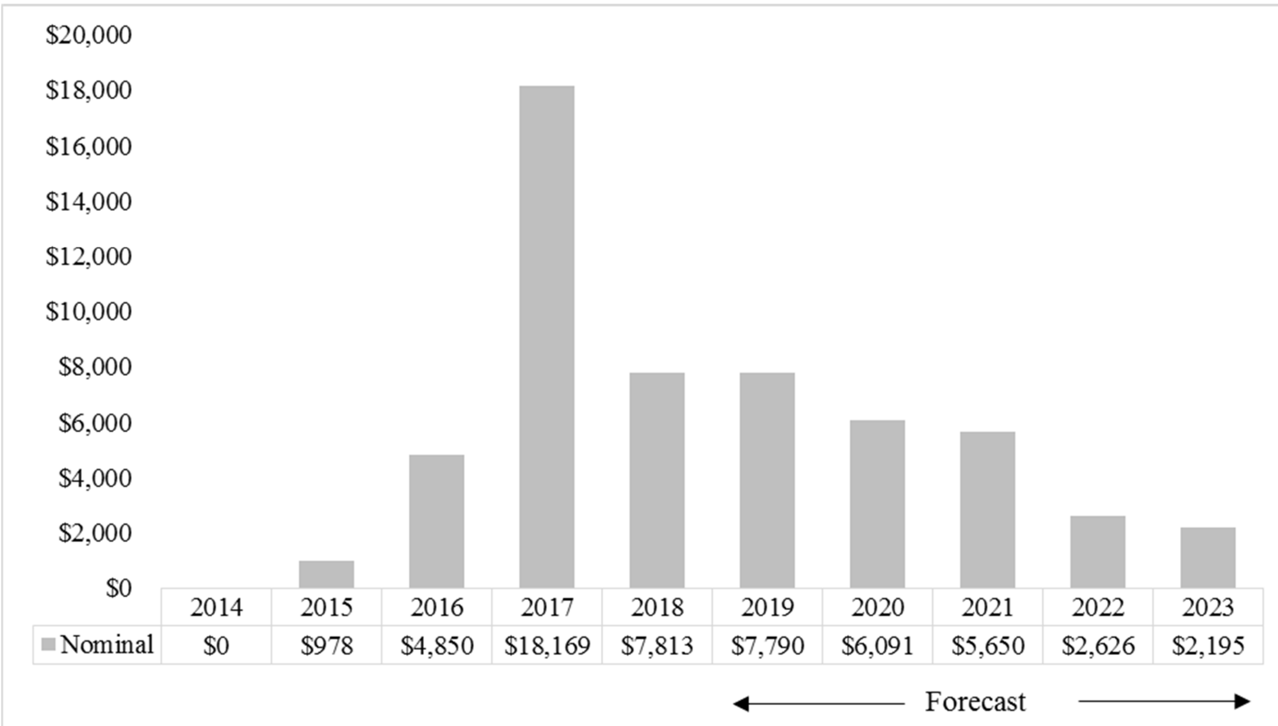
In its 2018 GRC testimony, SCE described alternatives that it considered before deciding to pursue the LTPT-SMT solutions. For the SMT, alternatives included continuing to use SCE's current tools and processes. However, this approach would not provide the level of accuracy required to interconnect higher levels of DERs. It would also provide insufficient response times to customers when interconnecting their resources to the grid. For the LTPT, alternatives included enhancing the existing planning tool to meet the new planning requirements. However, this was not pursued due to performance limitations of the existing tool, challenges in identifying qualified technical resources knowledgeable about the legacy technology, and the risks this would create for future scalability.

Figure II-12 summarizes the 2014–2018 recorded and 2019–2023 forecast capital expenditures for LTPT-SMT.

---

[87] D.18-02-004, OP 2.j and 2.1, p. 84.

Figure II-12
2014 – 2018 Recorded/2019-2023 Forecast Capital Expenditures for Long-Term Planning Tool and System Modeling Tool (LTPT-SMT)[88]
(Total Company - Nominal $000)



(2) <u>Basis for Capital Expenditure Forecast</u>

SCE based the LTPT-SMT capital forecast on staged software releases for 2019 to 2023. As previously noted, the revised capital forecast is higher relative to the 2018 GRC forecast due to the extent of the integration complexity and the corresponding level of engineering effort that was unknown during the 2018 GRC. The forecasted expenditures requested in this GRC testimony were derived based on the scope necessary to deliver several inter-dependent capabilities such as ICA at the circuit and substation levels, overall system capacity analysis, contingency analysis, reliability analysis, the system analysis dashboard, and project identification and scenario analysis.

The forecasted capital expenditures include software licensing of the core LTPT-SMT platform and labor costs for custom integration of the features associated with the

[88] CWBS Elements CIT-00-DM-DM-000-263 and CIT-00-DM-DM-000-264. Please refer to WP SCE-02, Vol. 2, Pt. 1, Ch. II – Book A - pp. 129 – 130 – Capital Details by WBS for LTPT and WP SCE-02, Vol. 2, Pt. 1, Ch. II – Book A - pp. 131 - 132 – Capital Details by WBS for SMT.

inter-dependent capabilities of the LTPT-SMT platform referenced above. SCE derived the software costs from vendor pricing obtained through competitive solicitations and by working closely with the selected vendors on the implementation scope. The LTPT-SMT capital forecast includes project labor, contract labor, software, hardware, and selected vendor costs.[89]

h) Grid Interconnection Processing Tool (GIPT)

(1) Program Description

The GIPT is a business process management tool that will allow customers and SCE to more quickly and efficiently connect electrical generation and load to the grid. The tool will centralize intake for various types of interconnection requests, including NEM, SCE's Tariff Rule 21 (Export and Non-export),[90] Wholesale Distribution Access Tariff (WDAT) and load interconnection projects.[91] The GIPT will improve the customer experience during application submittal by providing tariff eligibility options based on user input and allow customers to track the status of their interconnection applications. The GIPT will also reduce the number of manual operations throughout the interconnection project lifecycle by supporting the improvement and automation of business processes.

Additionally, the GIPT will provide SCE with timely and accurate interconnection information by consolidating load and generation information obtained throughout the interconnection process. The GIPT will record and consolidate the DER location information, DER electrical attributes, and DER contract-related information. This information will not only be used for system planning. It will also improve the accuracy of the data provided to the GMS.

SCE's existing interconnection portal merely enables customers to submit an application electronically and performs a minimal application review before delivering it to SCE personnel for completion. By comparison, the GIPT will have similar intake and review capabilities, but will also support the automation of system impact analysis, contract development and execution, key project milestone tracking, project cost tracking, and long-term contract management.

---

[89] Please refer to WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A - pp. 133 – 134 – LTPT Capital Workpaper and WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A - pp. 135 – 136 – SMT Capital Workpaper.

[90] SCE's Tariff Rule 21 is a tariff that describes the interconnection, operating and metering requirements for generation facilities to be connected to utility's distribution system.

[91] This refers to traditional load growth projects such as track homes and added facilities.

The GIPT will also be the central repository for all interconnection data collected throughout the process. Currently, DER information required for technical studies and contract-related information are maintained in separate databases. GIPT will maintain all interconnection information[92] by consolidating and replacing these multiple disparate databases, ensuring that it provides accurate and up-to-date data to the planning and operations tools.

The GIPT will also be capable of receiving and reviewing requests for new load service and/or updates to load service. Today, customers must submit these requests in hard or soft copy format to be reviewed manually, which results in inefficiencies. Digitizing these requests will improve the quality and integrity of data exchange between GIPT and other E&P and operations tools.

The shaded portion in Table II-12 identifies the high-level E&P capability supported by the GIPT.

Table II-12
GIPT-supported Capability

Capability Categories	High-level Capabilities
Engineering & Planning Integrates DERs into grid planning processes	a. Enhanced analysis of the grid's capacity to integrate DERs and of the DERs' potential locational net benefits
	b. Load and DER forecasting based on annual hour-based profiles
	c. Grid needs assessment based on annual hour-based profiles
	d. Risk-based distribution project portfolio management
	e. Streamlined DER and load interconnection process
	f. Electrical modeling and analysis of distribution system connectivity and hierarchy

SCE deferred the bulk of the GIPT project activities from 2016 to 2018. While the project scope remains unchanged, the initial GIPT implementations are now scheduled to occur in 2019 and 2020. From 2016 through 2018, SCE focused on evaluating multiple vendor solutions, conducting relevant proofs-of-concept, and concluding the competitive solicitation with a final vendor selection in early 2019.

In the 2021 GRC period, the first implementation of GIPT will focus on the process required to perform interconnections under Rule 21 Non-Export. SCE will also expand the

---

[92] E.g., Technology type, unite size and location, technical study reports, ownership, associated contracts.

GIPT functionality to accommodate the processes for the remaining DER interconnection tariffs, including NEM, Rule 21 Export, WDAT, and load requests.[93] The GIPT expansion will optimize the interconnection process, from intake to long-term contract management. The GIPT enhancements also include the ability to register DER aggregators[94] such that their association with various DER interconnections is made available to the DERMS.

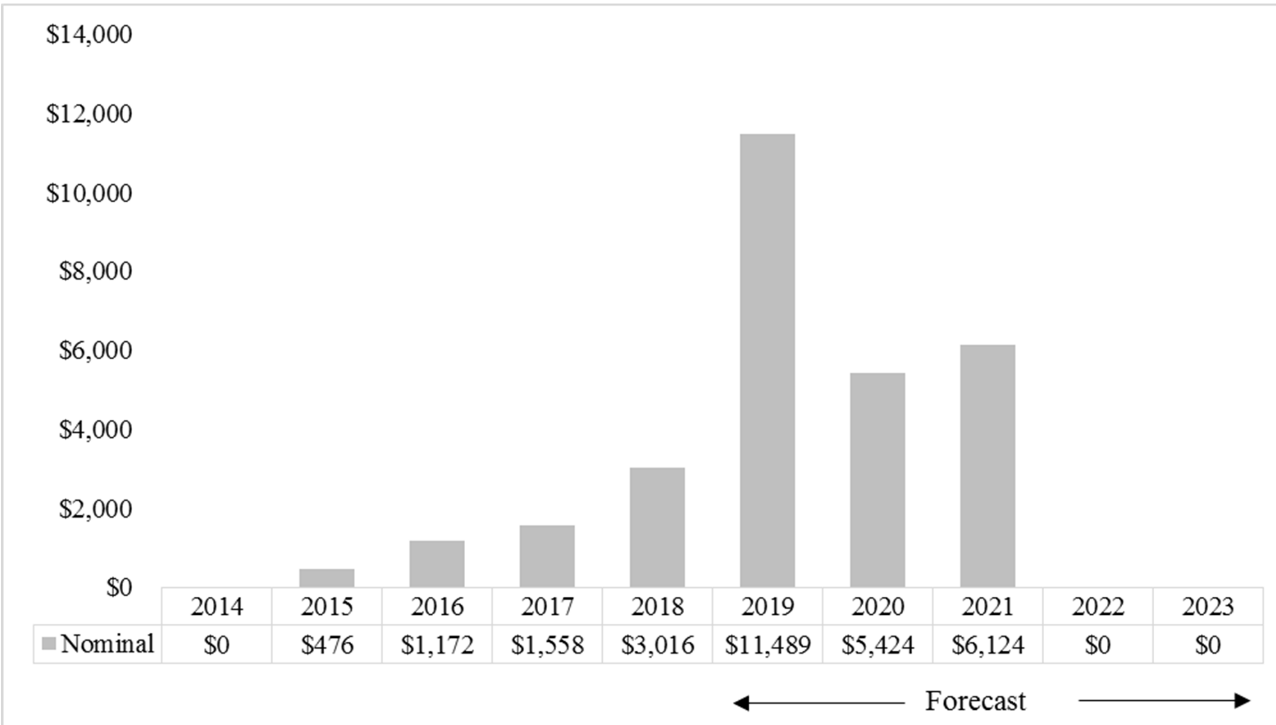
In its 2018 GRC filing, SCE described alternatives that it considered before deciding to pursue the GIPT solution. This included procuring a COTS solution for standalone project management solutions and workflow tools. SCE did not pursue this option since none of the COTS products appeared capable of addressing the complexity, reducing the manual steps, or providing the accurate information customers need. SCE also considered expanding the functionality of an existing pilot application to support the full GIPT scope, but did not pursue it since the pilot had multiple limitations, both in terms of functionality and technical viability.

Figure II-13 summarizes the 2014–2018 recorded and 2019–2023 forecast capital expenditures for GIPT.

[93] E.g., Electric vehicles load interconnections.

[94] This is a key functionality to support implementation of IEEE 2030.5 communication protocol. A DER aggregator is an entity that combines multiple small DERs and uses them to provide a grid service, potentially through wholesale energy markets.

Figure II-13
2014 – 2018 Recorded/2019-2023 Forecast Capital Expenditures for
Grid Interconnection Processing Tool (GIPT)[95]
CWBS Element CIT-00-SD-PM-000520
(Total Company - Nominal $000)



(2) <u>Basis for Capital Expenditure Forecast</u>

The GIPT capital expenditure forecast is based on the results of an RFP. The forecast, informed by the results of this competitive solicitation, is higher than the 2018 GRC request. The COTS product SCE had initially considered was insufficient for addressing the GIPT business requirements. However, although the alternative solution SCE selected provides greater flexibility, it also requires considerable custom configuration to implement various business process workflows. The GIPT capital forecast includes project team costs for labor, supplemental workers, consultants, software, hardware, and selected vendor costs. Please see the workpaper[96] for more detail.

---

95 Please refer to WP SCE-02, Vol. 2, Pt. 1, Ch. II – Book A - pp. 137 - 138 – Capital Details by WBS for GIPT.

96 Please refer to WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A - pp. 139 – 140 – GIPT Capital Workpaper.

i) **DRP External Portal (DRPEP)**

(1) **Program Description**

DRPEP is an interactive website that provides the public with detailed, up-to-date, and immediate access to information about a distribution circuit's ability to connect DERs to each circuit section.[97] The tool also publishes information produced as part of the annual planning process, which includes identifying opportunities for DERs to defer traditional grid infrastructure upgrades.

In the 2018 GRC, SCE proposed DRPEP investments to establish foundational information sharing capabilities based on the Commission's guidance in the DRP.[98] SCE has since implemented these foundational capabilities. DRPEP currently provides the general locations of SCE's distribution system assets, ICA results, and the LNBA,[99] GNA and DDOR reports. Circuit data is also available to customers in both a geospatial[100] and non-geospatial[101] format, while downloadable datasets are also available to DER developers with Application Programming Interface (API)[102] capabilities. This information helps 3rd parties to identify optimal interconnection locations.

In the 2021 GRC, SCE proposes DRPEP investments to continue publishing GNA, DDOR, LNBA and ICA reports, address new Commission requirements for publication,[103] automate the 15/15 Rule,[104] and position SCE to accommodate additional capabilities

97 This refers to ICA which the values are updated and published monthly.

98 Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resources Planning, dated February 6, 2015, in R.14-08-013, Attachment, pp. 8-9 (requiring utilities to include in their DRPs related to data access requirements, processes and procedures for receiving data from DER owners and operators).

99 LNBA identifies the benefits that DERs can provide at a given location, particularly benefits associated with meeting a specific distribution need within the electric service categories that can result in avoided cost.

100 I.e., Map.

101 I.e., Tabular.

102 Application Programming Interface: allows users to download data from centralized IT systems in bulk.

103 R.14-08-013, ALJ Ruling Modifying the Distribution Investment Deferral Framework Process, May 7, 2019.

104 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.

consistent with an upcoming Commission decision on the ICA Working Group's (WG) Final ICA WG Long Term Refinements Report.[105]

Table II-13 identifies in shading the two high-level E&P capabilities supported by the DRPEP.

Table II-13
DRPEP-supported Capabilities

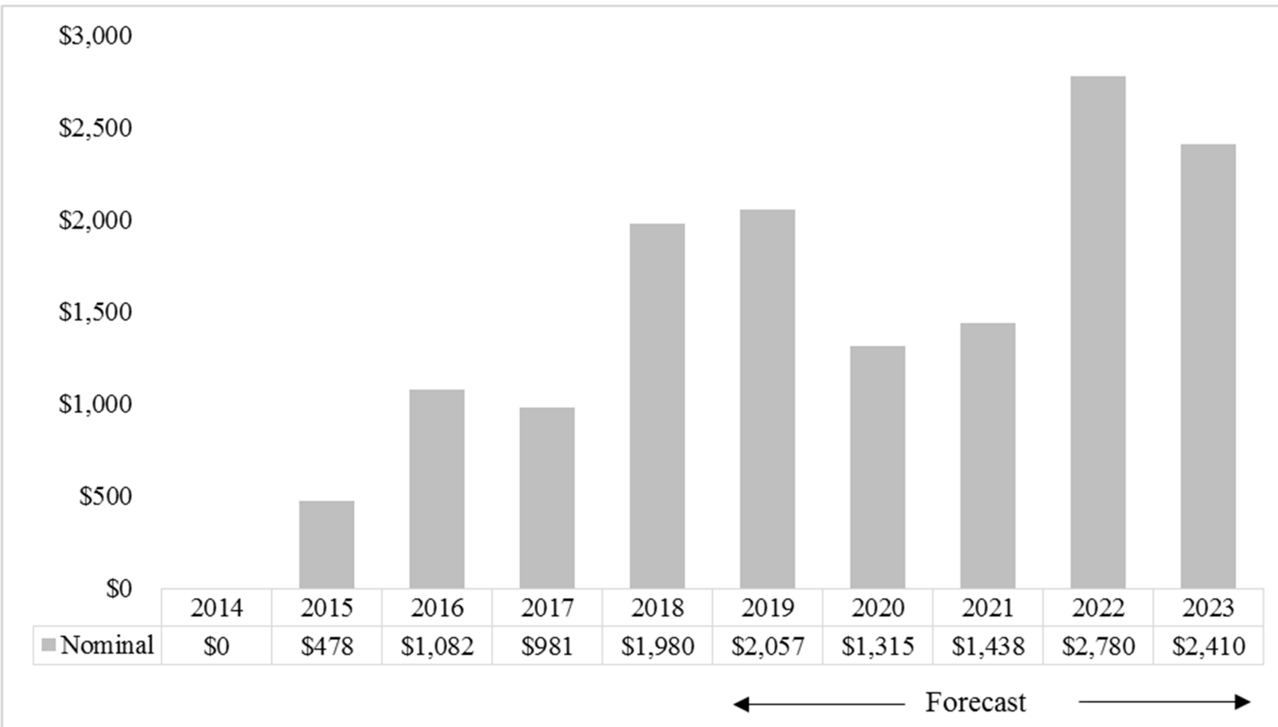
Capability Categories	High-level Capabilities
Engineering & Planning Integrates DERs into grid planning processes	a. Enhanced analysis of the grid's capacity to integrate DERs and of the DERs' potential locational net benefits
	b. Load and DER forecasting based on annual hour-based profiles
	c. Grid needs assessment based on annual hour-based profiles
	d. Risk-based distribution project portfolio management
	e. Streamlined DER and load interconnection process
	f. Electrical modeling and analysis of distribution system connectivity and hierarchy

The DRP and associated demonstration projects require that SCE publish large amounts of data on circuit attributes. In its 2018 GRC filing, SCE described alternatives considered before deciding to pursue the DRPEP solution, including combining SCE's legacy DERiM tool with SCE.com to publish the required data. However, SCE concluded that this approach would not meet its customers' needs. The DERiM tool was designed to present data only in a map format and would not be effective in providing the required amounts of data in the necessary tabular format. This conclusion is even more reasonable today given the additional data elements required by the Commission for the GNA and DDOR.

Figure II-14 summarizes the 2014–2018 recorded and 2019–2023 forecast capital expenditures for DRPEP.

[105] *See,* ALJ's Ruling requesting comments on refinements to the ICA, dated July 3, 2019, in, R. 14-08-013, p. 6, Questions 2-3 to be addressed by parties referencing Integration Capacity Analysis Working Group Final ICA WG Long Term Refinements Report.

Figure II-14
2014 – 2018 Recorded/2019-2023 Forecast Capital Expenditures for
DRP External Portal[106]
CWBS Element CIT-00-DM-DM-000265
(Total Company - Nominal $000)



(2) <u>Basis for Capital Expenditure Forecast</u>

SCE based the capital expenditure forecast for DRPEP on planned sequential releases starting from 2019 to 2023. The costs include software licensing and labor for the necessary data and system integration. More specifically, SCE derived the forecasted expenditures based on the costs incurred during the initial releases completed since 2017. These releases helped inform estimates for the COTS software portion as well as the labor required to complete the necessary data and system integration. The capital forecast for DRPEP includes project team costs for SCE employees, supplemental workers, consultants, software, and selected vendor costs.[107]

[106] Please refer to WP SCE-02, Vol. 2, Pt. 1, Ch. II – Book A - pp. 141 – 142 – Capital Details by WBS for DRPEP.

[107] Please refer to WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A - pp. 143 - 144 – DRPEP Capital Workpaper.

2. Capital Expenditures for Communications

a) High-level Program Description

SCE's new communications system is a critical component of the Grid Modernization program, enabling SCE to communicate cyber-securely and in real-time between grid devices (including DERs), distribution substations, and SCE's operations control centers. This communications capability directly enables various grid management functions, including real-time situational awareness, analyzing and resolving grid reliability issues, and integrating and controlling DERs. SCE's new communications system will also enable secure integration with DER aggregators and other 3rd parties, which will support the use of DERs to provide reliability services to the distribution system. Communications includes four components:

1. **FAN**: The new wireless radio network that will replace SCE's aging NetComm system.
2. **Distribution System Efficiency Enhancement Program (DSEEP)**: Support of SCE's NetComm system to ensure it supports SCE's communications needs until the new FAN is fully deployed.
3. **CSP**: The computing platform that enables secure communication between the operations control centers, substation equipment, and distribution circuit devices.
4. **WAN**: The fiber optic cable that provides the crucial communications link between the FAN, CSP, substations and SCE's operations control centers.

A complete communications system must provide connectivity between all grid devices, substations and key SCE facilities and also satisfy SCE's operational requirements in terms of capacity, speed, coverage, availability, and security. Figure II-15 illustrates how the three key communications components (FAN, CSP, and WAN) integrate to provide communications between grid devices (including DERs), distribution substations, and SCE's operations control centers. First, devices on the distribution circuit will communicate with the distribution substation using the FAN. Second, the CSP will serve as the communications hub within the substation, linking the FAN and the local substation devices to the WAN. Finally, the WAN provides the communications path from the substation to SCE's operations control centers using high-speed, high-capacity, fiber optic wires. The combination of the FAN, CSP, and WAN establishes bi-directional communications between grid devices, substations, and the operations control centers. All three elements must operate together for the communications system to provide the fully-integrated communications capability needed for SCE's Grid Modernization program. Moreover, the entire Communications system (FAN, CSP, and WAN) is needed to address the immediate needs of the existing distribution grid regardless of the extent or timing of additional distribution automation needs in the future.

Figure II-15
Communications Elements in Grid Modernization

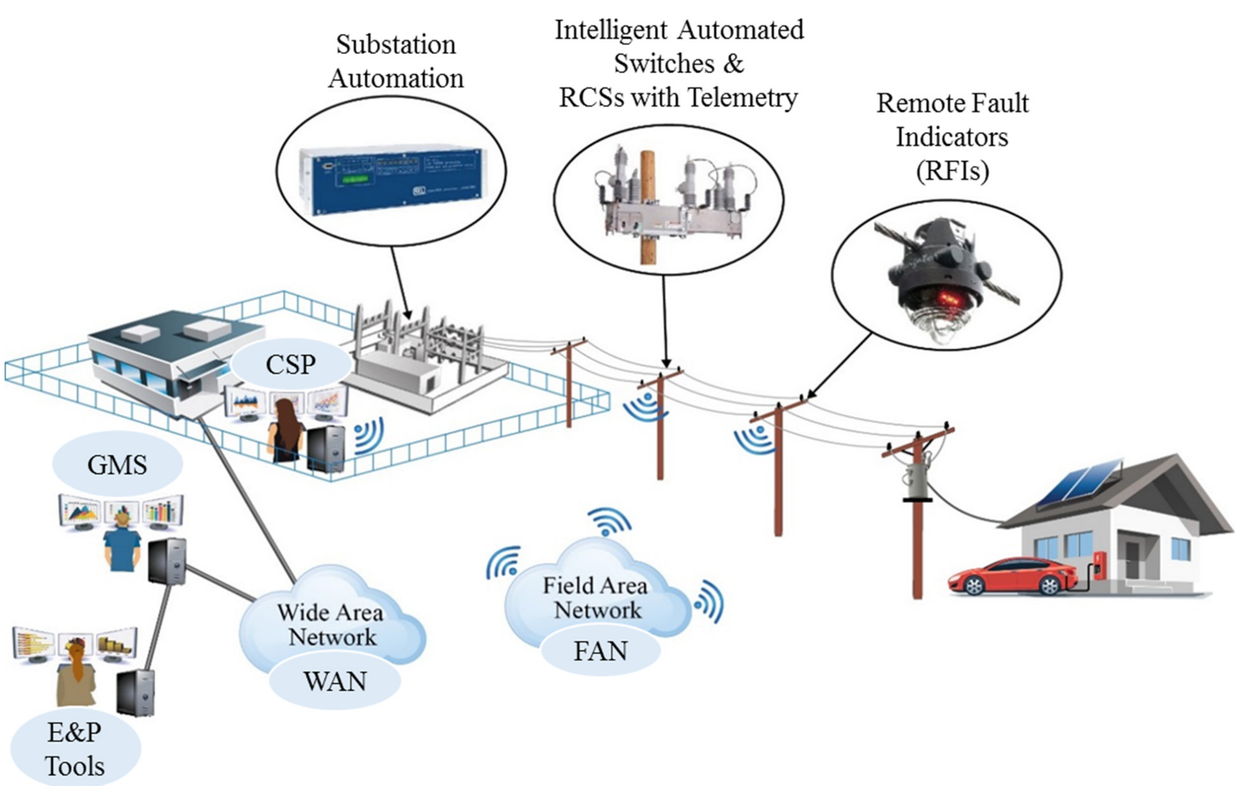


Table II-14 summarizes the high-level capability that SCE expects Communications will directly provide. The table also identifies the Automation and Grid Management capabilities that are enabled through the new communications system.

Table II-14
Communications-enabled Capabilities

Capability Categories	High-level Capabilities
Communications Enables the Grid Management System to communicate securely with DERs and other grid devices	a. Cyber-secure communications between distribution grid devices, substations and operations control centers
Automation Improves grid monitoring and control using real-time telemetry directional power flow data	a. Grid condition data collection and awareness
	b. Automatic execution of grid reliability issue mitigations
Grid Management Enables grid operators to monitor grid conditions in real-time and control field devices remotely	a. Advanced distribution and outage management
	b. Grid reliability issue mitigation analysis
	c. DER state and constraint assessment
	d. DER grid services analysis

b) <u>Summary of Cost Forecast</u>

Table II-15 summarizes the 2014–2018 recorded and 2019–2023 forecast capital expenditures for Communications. In addition to DSEEP expenditures in 2014 and 2015, SCE initiated the FAN, CSP, and WAN in 2016 and continued ramping up project activities, especially for FAN where considerable progress resulted in the build out of the new lab environment, evaluation of several vendor products, and implementation of a limited, functioning system in the production environment for field testing. Since 2016, SCE has incurred CSP expenditures to complete the standard hardware design and the acquisition and testing of prototype units in the lab and at designated substation locations. SCE has also made progress with the WAN in support of the FAN, CSP, and the SA-3 pilots conducted between 2016 and 2018.

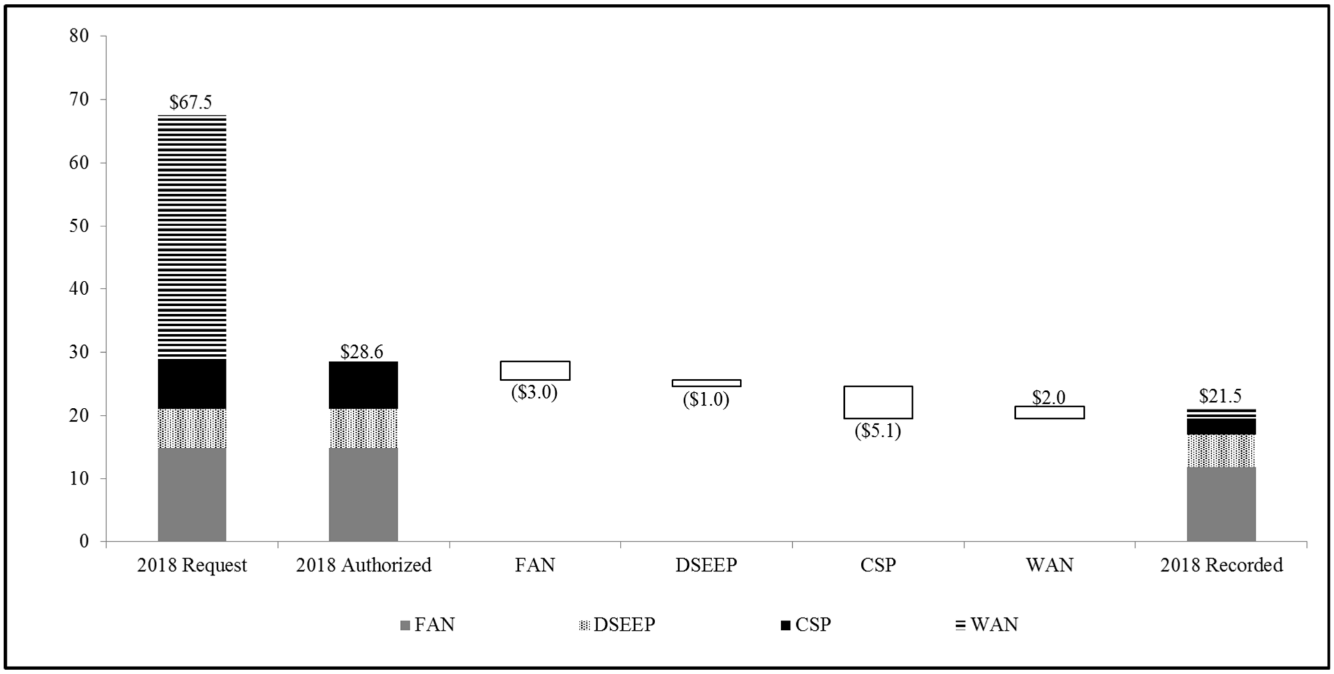
Table II-15
Communications Capital Expenditure Summary
Recorded 2014-2018/Forecast 2019-2023
(Total Company - Nominal $000)

	Recorded					Forecast				
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Field Area Network			$478	$6,032	$11,823	$6,673	$8,638	$59,128	$72,377	$81,233
Distribution System Efficiency Enhancement Project	$4,518	$4,309	$4,293	$4,846	$5,221	$5,412	$5,532	$5,532	$5,532	$5,532
Common Substation Platform			$180	$1,362	$2,467	$691	$629	$422	$4,149	$4,086
Wide Area Network			$513	$1,241	$1,982	$669	$659	$7,289	$1,983	$1,915
Communications Totals	**$4,518**	**$4,309**	**$5,464**	**$13,481**	**$21,493**	**$13,445**	**$15,458**	**$72,371**	**$84,040**	**$92,766**

c) <u>Comparison of Authorized 2018 to Recorded</u>

The 2018 GRC Decision requires SCE to compare 2018 authorized amounts to 2018 recorded amounts. Figure II-16 below compares these amounts for Communications capital expenditures.

Figure II-16
Communications[108]
2018 GRC Authorized Variance Summary 2018 Capital
(Total Company - Constant 2018 $Millions)



The 2018 recorded expenditures for Communications were less than the amount authorized. Due to the timing impact of the 2018 GRC Decision, SCE decided to defer most of the FAN capital expenditures to mitigate potential financial risks. This resulted in SCE deferring the CSP and WAN investments, given their dependency on the FAN. As described earlier in this section, the CSP and WAN are needed to connect the FAN to SCE's operations control centers. Given the delayed FAN implementation, the CSP and WAN deployments were also deferred to maintain the alignment of the overall Communications implementations. However, prior to receiving the 2018 GRC Decision, SCE proceeded with key project activities for the FAN and CSP design and technology evaluations, which resulted in variances of $3.0 million and $5.1 million, respectively, as shown in Figure II-16. Meanwhile, the DSEEP project continued to support the existing NetComm system.

[108] Please refer to WP SCE-02, Vol. 2, Pt. 1, Ch. II – Book A - pp. 119 – 120 – Grid Modernization Authorized to Recorded Details.

d) Need for Capital Program

Technology factors drive SCE's need for the capability that Communications enables. The specific investment drivers and the customer benefits SCE expects to result from Communications are summarized below.

(1) Drivers

(a) Technology Drivers

SCE's NetComm system is marginally adequate for the volume of grid devices currently deployed. NetComm is a legacy network comprising roughly 56,000 radios communicating through 121 geographically-dispersed WAN access points or "head ends." These radios enable field communications for approximately 27,000 automated distribution devices and approximately 20,000 commercial and industrial meters. The typical time between when an operator issues a command signal for a device to operate and when the operator receives confirmation back from the device of a successful operation (the command cycle time) is two minutes. Future automation schemes that respond to unplanned outages will require command cycle times to be less than 30 seconds. The NetComm system cannot support the gradual increase in the number of distribution automation devices. In addition, NetComm upgrades would not meet SCE's requirements for increased bandwidth, lower latency (faster round-trip message delivery), computational capabilities on edge devices,[109] and additional cybersecurity controls. Lastly, the NetComm system was designed 20 years ago when many cybersecurity risks and the tools to guard against them did not exist. While SCE has integrated cybersecurity tools and controls into its existing NetComm system to-date, SCE anticipates that the current system will not suffice as cybersecurity threats evolve. The Commission's approval of the FAN in the 2018 GRC Decision supported SCE's conclusion that the NetComm system is no longer a viable option.[110]

This testimony describes how realizing the benefits of a flexible, modern grid requires equipment and software to acquire grid data (including real-time load and generation), perform analysis, and perform remote and automatic switching. Increasing amounts of data

---

[109] Edge devices consist of assets deployed in targeted areas of the distribution grid between the customer meter and the distribution substation.

[110] D.19-05-020, p. 113 "We find that the FAN is needed now, based on expected cybersecurity benefits and in order to ensure that distribution devices have sufficient communications."

and controls necessary for these capabilities require a cyber-secure communications system. SCE currently lacks the ability to provide the remote control logic[111] necessary to effect local automated decision making to realize these capabilities and associated benefits. The CSP is a computing platform designed to facilitate secure communications and maintain data integrity, which will allow SCE to optimize the performance of distribution grid devices locally, including DERs. Without the CSP, the secure integration of the edge and substation assets with the operations control centers would not be feasible.

The FAN will transmit information and control signals from the grid assets to the CSP, but a path is needed to transmit this information to the operations control centers. Information and control signals from the substation assets will also go through the CSP and, likewise, need a communications path to the operations control centers. Proper operation of the substation and distribution grid assets will not be possible without a high-speed and secure WAN to transmit data from the grid and substations back and forth to the operations control centers.

(b) Benefits

(i) Safety

The improved telemetry and switching capabilities provided by SCE's Grid Modernization approach will improve SCE's ability to monitor and respond to real-time conditions on the distribution system. This will enable SCE to mitigate potential safety hazards more quickly, reducing the potential for customer and workforce exposure to such hazards. Since distribution automation functions will reduce the number of customers impacted by outages, outage frequency, and outage duration, customers responsible for maintaining the safety, security and health of customers living in SCE's service territory will experience fewer and shorter periods without electric service. All three Communications technologies (FAN, CSP, and WAN) contribute to this safety benefit since they provide a reliable and cyber-secure communication link between field equipment, the GMS, and the operations control centers.

(ii) Reliability

Modernizing the distribution grid is expected to eliminate a substantial share of momentary and sustained outages for customers on circuits through the various automation enhancements. All three Communications technologies (FAN, CSP, and WAN) contribute to

[111] An example of remote control logic is the DERMS software components installed and operating at the substation.

enabling these reliability benefits since they provide a reliable, cyber-secure communication link between field equipment, the GMS and the operations control centers.

(iii) Decarbonization

The granular circuit segment data collected by SCE's automation equipment will support system planners in identifying more opportunities and locations to consider traditional grid infrastructure investments to be deferred with DERs. To the extent this increases DER penetration, there will be a reduced need for incremental GHG-emitting resources. All three Communications technologies (FAN, CSP, and WAN) contribute to enabling this benefit since they provide a reliable, cyber-secure communication link between field equipment, the GMS, and the E&P software tools.

(iv) Customer Empowerment

Enhanced DER telemetry, which relies on the Communications system, will help empower customers with cleaner energy choices by helping to integrate higher amounts of DERs on targeted distribution circuits. All three Communications technologies (FAN, CSP, and WAN) contribute to this customer benefit since they provide a reliable, cyber-secure communication link between field equipment, the GMS, and the operations control centers.

(v) Economic Efficiency

The switches capable of interrupting fault current reduce the number of times a distribution feeder has to open and close its circuit breaker to test for the fault location during outage events. Since these operations contribute to cable and conductor aging, reducing these operations should therefore contribute to the health of these grid assets and potentially improve the performance of customer DERs—since they will detect fewer losses of voltage requiring them to stop feeding power back to the grid. All three Communications technologies (FAN, CSP, and WAN) contribute to enabling economic efficiency since they provide a reliable, cyber-secure communication link between field equipment, the GMS, and the operations control centers.

e) Field Area Network (FAN)

SCE's existing field communications network connects distribution substations and distribution automation devices using NetComm, a radio-based communications system. The new FAN will replace the NetComm system with a wireless system capable of supporting the capacity, speed, connectivity, and cybersecurity needs of current and future grid devices to support automation.

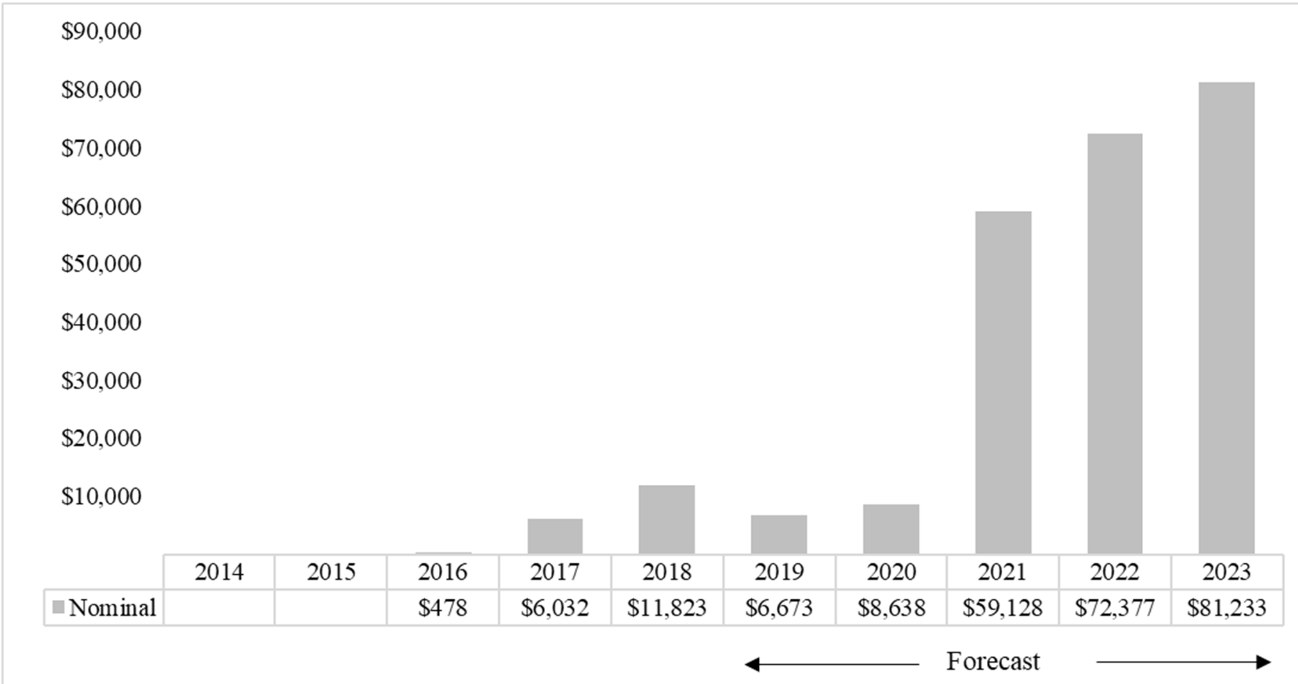
(1) Program Description

The FAN will deliver SCE's next generation wireless field communications network. It 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 protect data from cyber threats while supporting integration of 3rd party devices.

The FAN deployment will take several years due to the scale of SCE's service territory. During this deployment, and in order to maintain grid safety and reliability, SCE must also continue to maintain the NetComm system until the new FAN is fully deployed. Maintenance activities will include replacing inoperable radios and deploying new NetComm radios to support new automation devices where the new FAN has not yet been deployed. SCE carefully considered potential alternatives to the FAN, such as continuing to use the NetComm network and possibly using the AMI wireless infrastructure. SCE determined that both alternatives were unacceptable due to technical infeasibility and other potential risks, including cybersecurity concerns.

Figure II-17 summarizes the 2014–2018 recorded and 2019–2023 forecast capital expenditures for FAN.

Figure II-17
2014-2018 Recorded/2019-2023 Forecast Capital Expenditures for Field Area Network (FAN)[112]
CWBS Element CIT-00-OP-NS-781701
(Total Company - Nominal $000)



(2) <u>Basis for Capital Expenditure Forecast</u>

SCE derived the projected FAN costs based on a competitive procurement process that resulted in pricing from the preferred FAN vendor. Given the schedule change resulting from the 2018 GRC Decision and the extended period required for technology assessments, SCE added costs to accommodate the temporary use of commercial carrier services for certain DER integration and monitoring applications until FAN is available. The capital forecast for the FAN includes project team costs for SCE employees, supplemental workers, consultants, software, hardware, and selected vendor costs. Please see the workpaper[113] for more detail.

---

[112] Please refer to WP SCE-02, Vol. 2, Pt. 1, Ch. II – Book A - pp. 145 – 146 – Capital Details by WBS for FAN.

[113] Please refer to WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A - pp. 147 – 148 – FAN Capital Workpaper.

As shown in Figure II-17, the year-over-year spend will remain steady in 2019 and 2020 and then increase as the FAN deployment accelerates starting in 2021. SCE anticipates the FAN deployment will conclude in 2028.

f) Distribution System Efficiency Enhancement Program (DSEEP)

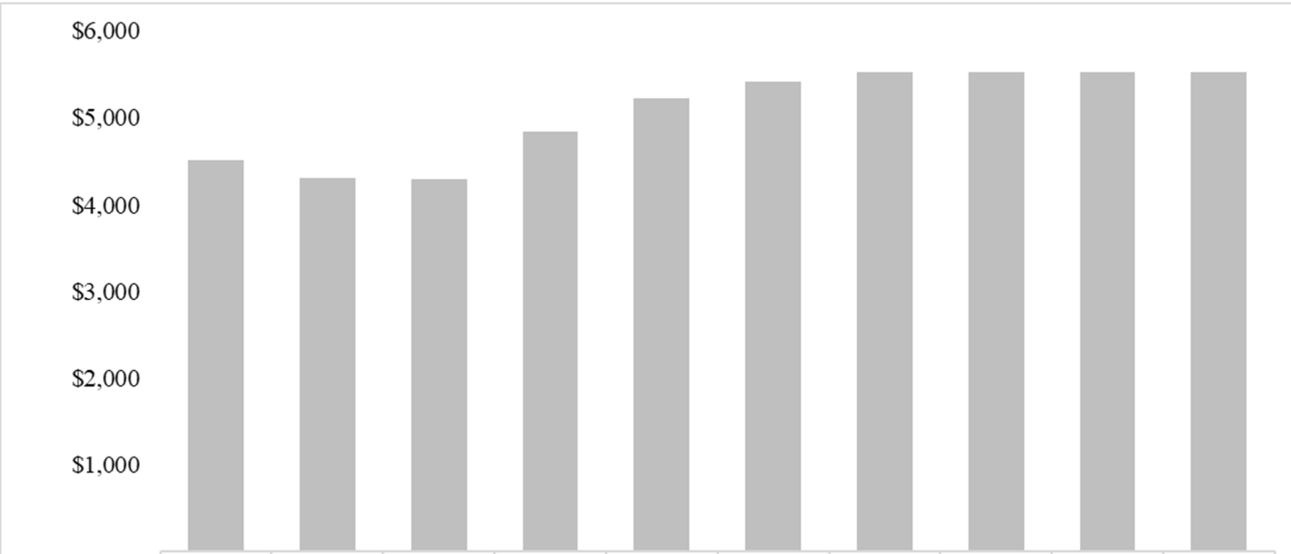
The DSEEP will ensure that grid devices are able to communicate with the operations control centers prior to completion of the FAN deployment. This includes providing radios for the new grid devices planned for deployment over the next few years. It also includes maintaining or replacing the NetComm wireless communications components that support the grid devices already in operation.

(1) Program Description

During the FAN deployment (expected through 2028), the DSEEP project will continue to replace aging portions of the existing NetComm network and damaged or failed radios that support distribution automation devices. Under DSEEP, SCE will install radios in each distribution automation device deployed before the FAN is complete. Each distribution automation device requires one radio. Under the DSEEP, SCE expects to deploy over 15,000 NetComm radios to support new distribution automation devices and replace non-functioning radios from 2019 to 2023.

Figure II-18 summarizes the 2014–2018 recorded and 2019–2023 forecast capital expenditures for DSEEP.

Figure II-18
2014-2018 Recorded/2019-2023 Forecast Capital Expenditures for Distribution System Efficiency Enhancement Program (DSEEP)[114]
CWBS Element CIT-00-OP-NS-000014
(Total Company - Nominal $000)



	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Nominal	$4,518	$4,309	$4,293	$4,846	$5,221	$5,412	$5,532	$5,532	$5,532	$5,532

(2) Basis for Capital Expenditure Forecast

SCE's projected five-year capital forecast of $27.540 million for DSEEP is based on the number of NetComm radios needed annually to accommodate net new distribution automation devices and replacement of failed radios already deployed. SCE forecasts that DSEEP will need 3,000 radios annually based on the annual device failure rate and the planned deployments for new distribution automation devices. DSEEP's historical recorded costs for installing and/or replacing each NetComm radio form the basis of SCE's DSEEP forecast.[115]

[114] Please refer to WP SCE-02, Vol. 02, Pt. 1, Ch. II – Book A - pp. 149 – 150 – Capital Details by WBS for DSEEP.

[115] Please refer to WP SCE-02, Vol. 04, Pt. 1, Ch. II – Book A - pp. 151 - 152 – DSEEP Capital Workpaper.

g) **Common Substation Platform (CSP)**

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

(1) **Program Description**

The CSP workstream will deploy the new computing platform in distribution substations using virtualization technology to monitor, manage, control, and provide cybersecurity to substation and circuit devices. The CSP will include redundant servers to mitigate potential server outages. SCE will manage the CSP remotely and can therefore deploy software packages, including cybersecurity upgrades, remotely from a central operations center.

The CSP will host the following applications:

- **Distributed control and data acquisition**

The CSP will serve as the communications hub for transmitting data gathered from field devices to the operations center. The CSP will also serve as the portal for the operations center to remotely operate substation and circuit equipment.

- **Control protocol translation functions**

The CSP will enable communication between different grid devices. The CSP will gather data and transmit the data to other grid devices or to the GMS at the operations control center.

- **Cybersecurity controls**

The CSP provides cybersecurity controls and functions to protect the grid devices and operations control centers from cyber-attacks. These applications will include firewall functions, intrusion detection and protection, access controls, integrity management checks, and encryption support.

- **Distributed Control functions**

The CSP could allow control decisions to be made locally at the substation by hosting software components from GMS or other control applications. This will increase the speed of operation and response of automation equipment and DERs.[116]

SCE considered alternatives to the CSP, such as using three different computing devices and separate physical firewall appliances[117] at each substation. The alternatives would not provide the efficiencies of the CSP in implementing hardware redundancy, virtualization, and remote management capabilities.[118]

Figure II-19 summarizes the 2014–2018 recorded and 2019–2023 forecast capital expenditures for CSP.

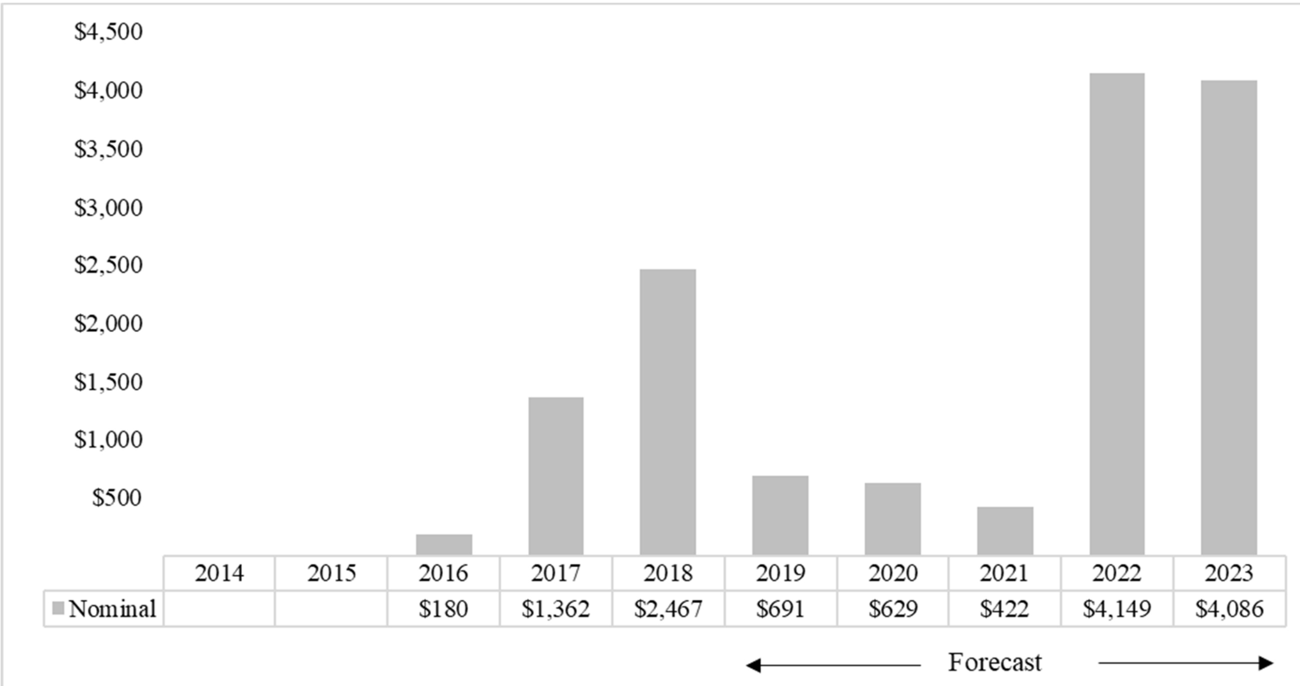
---

[116] An example of this would be the installation of DERMS software agents on the CSP and enabling the control functions to occur at the substation.

[117] Firewall appliances are specialized computers used for cybersecurity purposes.

[118] Hardware redundancy is the ability to have multiple identical physical components so that if one fails, the other one can be used instantly for back-up without service interruption; virtualization uses software to simulate a physical hardware machine; remote management is the ability for a user to access remote equipment via software to perform inspection, change settings, update software images, and download information, as needed.

Figure II-19
2014-2018 Recorded/2019-2023 Forecast Capital Expenditures for Common Substation Platform (CSP)[119]
CWBS Element CIT-00-OP-NS-781702
(Total Company - Nominal $000)



(2) <u>Basis for Capital Expenditure Forecast</u>

SCE based its forecast for the CSP[120] capital expenditures of $9.977 million on a competitive RFP, which resulted in SCE selecting a vendor. To forecast the capital expenditures, SCE applied the vendor unit pricing to the CSP scope and schedule, which is based on the FAN deployment schedule. This revised CSP capital forecast is less than the amount approved in the 2018 GRC Decision.[121]

[119] Please refer to WP SCE-02, Vol. 2, Pt. 1, Ch. II – Book A - pp. 153 – 154 – Capital Details by WBS for CSP.

[120] Please refer to WP SCE-02, Vol. 2, Pt. 1, Ch. II – Book A - pp. 155 – 156 – CSP Capital Workpaper.

[121] D.19-05-020, p. 113 approved SCE's request for $11.446 million.

h) Wide Area Network (WAN)

The WAN consists of the communications hardware necessary to transmit data from the FAN and substations to SCE's control operations centers. Such connectivity enables real-time monitoring and control of distribution grid and substation equipment.

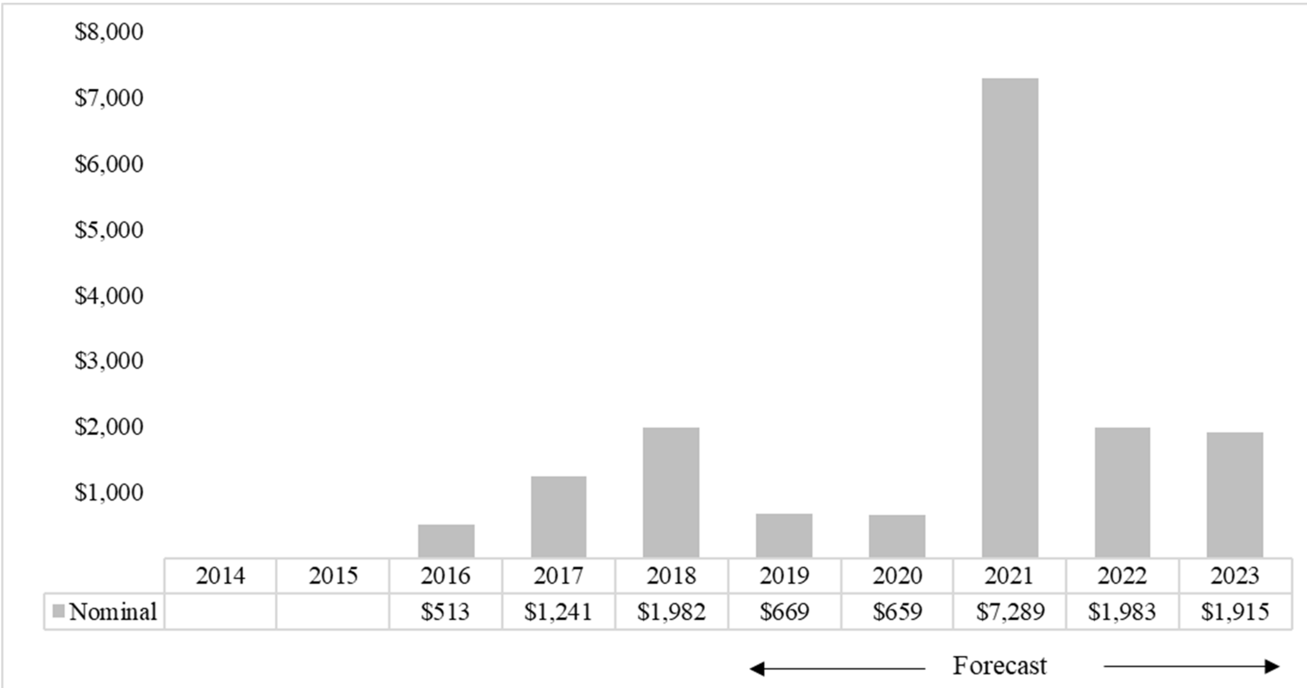
(1) Program Description

The WAN establishes communications connectivity between the CSP (and substations) and the operations control centers. This will allow the FAN to transmit data from the grid devices to the GMS in the operation control centers. The WAN will enable the field devices, substations, and the operation control centers to transmit large amounts of data between each other. Because of its speed and capacity, fiber optic cable is the preferred means of data transmission for the WAN. SCE will deploy WAN technology for specific substations that do not currently have a WAN.

SCE considered pursuing a wireless solution as an alternative to the WAN. However, this option would require a significantly larger investment, be subject to capacity and performance limitations, and add a new layer of cybersecurity challenges.

Figure II-20 summarizes the 2014–2018 recorded and 2019–2023 forecast capital expenditures for WAN.

Figure II-20
2014-2018 Recorded/2019-2023 Forecast Capital Expenditures for Wide Area Network (WAN)[122]
CWBS Element CIT-00-OP-NS-781703
(Total Company - Nominal $000)



	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Nominal			$513	$1,241	$1,982	$669	$659	$7,289	$1,983	$1,915

(2) <u>Basis for Capital Expenditure Forecast</u>

SCE based its forecast for the WAN capital expenditures of $12.515 million on a standard engineering design, a standard hardware platform, and known costs from similar fiber optic cable deployments. To forecast the capital expenditures, SCE aligned with the scope and schedule of the FAN and CSP deployments, since these deployments are dependent upon the WAN. The expenditure forecast was derived by multiplying the unit cost per WAN installation by the units forecasted to be installed.[123]

[122] Please refer to WP SCE-02, Vol. 2, Pt. 1, Ch. II – Book A - pp. 157 – 158 – Capital Details by WBS for WAN.

[123] Please refer to WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A - pp. 159 – 160 – WAN Capital Workpaper.

3. Capital Expenditures for GMS

a) High-level Program Description

SCE's GMS is an advanced software platform that will integrate multiple systems designed to manage our increasingly dynamic grid. In the 2018 GRC,[124] SCE described potential options for the GMS. Based on the evaluations SCE conducted from 2016 to 2018, SCE will implement an ADMS with a DER Management System (DERMS) and a set of advanced applications, all of which SCE will need to integrate. The GMS will replace SCE's legacy DMS, which was deployed in 2010, has become obsolete and is no longer supported by the vendor. The GMS will also replace the existing OMS to provide integrated grid management functionality. The ADMS will provide the combined DMS/OMS functionality. This 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. Such information will be transmitted from smart meters, distribution automation devices, DER telemetry devices and smart inverters. 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.

The GMS will also include a DERMS, which will be used to communicate and interact with DERs and create the necessary interfaces required to integrate with DER aggregators or other 3rd parties in accordance with SCE's Tariff Rule 21 update. The GMS advanced applications will include the optimization engine, data historian, device management, adaptive protection system, business rule engine, and short-term forecasting engine.

SCE expects the GMS will reduce CMI by 36 million annually by 2022.[125] Based on SCE's Benefit-Cost Analysis (BCA), the GMS will provide SCE's customers with reliability benefits that exceed the cost of the GMS by a factor of five.[126] Since the BCA only analyzes the reliability benefits of this investment, the BCA is conservative. Other benefits expected to result from this investment, but which are not quantified in the BCA, include safety, decarbonization, and economic efficiency.

---

[124] Please refer to Application No. A.16-09-001, Exhibit No. SCE-02, Vol. 10.

[125] Please refer to WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A - pp. 161 – 164 – Grid Modernization GMS Benefit Cost Analysis Summary.

[126] Please refer to WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A - pp. 161 - 164 – Grid Modernization GMS Benefit Cost Analysis Summary.

Table II-16 summarizes the four high-level capabilities that SCE expects the GMS to enable.

Table II-16
GMS-enabled Capabilities

Capability Categories	High-level Capabilities
Grid Management Enables grid operators to monitor grid conditions in real-time and control field devices remotely	a. Advanced distribution and outage management
	b. Grid reliability issue mitigation analysis
	c. DER state and constraint assessment
	d. DER grid services analysis

In the 2021 GRC period, SCE will continue focusing on enabling the following key GMS capabilities:

- **Real-time Situational Awareness and Analysis:** The GMS will allow users to perform real-time power system analysis including protection analysis,[127] evaluating planned and unplanned outages, monitoring DER performance, and identifying load masked by DERs.
- **Power Flow Optimization:** The GMS will enable power flow optimization to prioritize specific objectives for grid reliability services. This includes using distribution capacitors, voltage regulators and smart inverters to optimize the system voltage.
- **Operational Planning:** The GMS will enable operational planning capabilities that provide guidance to SCE's system operators and operations engineers regarding forecasted changes in load and generation based on weather and other factors. This capability also will assist system operators and operations engineers with analysis of short-term grid needs[128] and will

[127] This will enhance public and worker safety and reduce the likelihood of equipment damage during circuit reconfigurations specifically in High Fire Risk Areas (HFRA).

[128] E.g., Contingency analysis; simulations of various future scenarios that include load and DER forecasts to prepare for planned outages.

inform other advanced application within GMS with the result of operational planning.

- **Assisted and Automated Switching:** The GMS will enable assisted switching and self-healing grid[129] to minimize the effect of planned outages, equipment overloads, system faults, automated wire-down and high impedance fault detection.[130]
- **Interaction with DERs:** The GMS will interact with DERs using the IEEE 2030.5 protocol.[131] This will allow system operators and operations engineers to interface with smart inverters and DERs for system reliability and to optimize the use of DERs for grid services. System operators will be able to monitor DER output and manage DERs. The GMS also will identify when DIDF resources and other DERs can be dispatched for grid services and system reliability needs.
- **Manage Microgrids:** The GMS will provide system operators and operations engineers with the ability to monitor and manage DERs and generation both within the microgrid and on SCE's electrical grid, leveraging them to optimize system power flows.
- **Process Improvement:** The GMS will improve various aspects of SCE's grid operations process, including enabling electronic switching management. The GMS will eliminate the need for manual and paper-based outage and distribution management workflows, enable quicker response times to outage restoration, streamline workflows, and reduce human performance errors.

---

[129] This capability reduces the outage times after a system fault. Fault Location Isolation and System Restoration (FLISR) is one form of self-healing functionality that detects the system fault, isolates the faulted section, and restores customer load.

[130] Meter Alarming of Downed Energized Conductors (MADEC) is a wire-down detection application developed by SCE which leverages the AMI data to detect down energized wire and high impedance. A high-impedance fault results when an energized primary conductor comes in contact with a quasi-insulating object such as a tree, structure or equipment, or falls to the ground. These types of faults generally are not detected by conventional protective devices (i.e. circuit breakers, circuit automatic reclosers and branch line fuses).

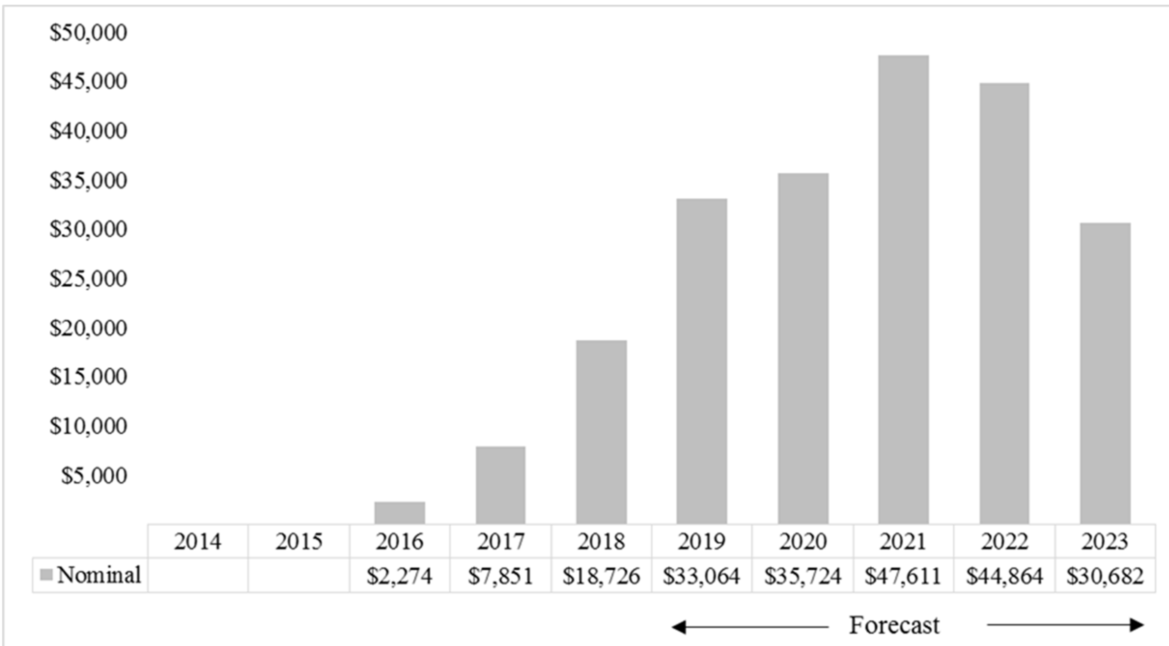
[131] IEEE 2030.5 defines the standard protocol used for interacting with smart inverters.

- **Highly Resilient Design:** To support continuous system operation, the GMS will have infrastructure management applications that will monitor the condition of the software and hardware that support it. The GMS will have both local and geographical redundancies.
- **Support Multivendor Technologies:** GMS will be built on a platform that supports multivendor interoperability in order to manage operating complexity across multiple grid management functions.

b) <u>Summary of Cost Forecast</u>

Figure II-21 summarizes the 2014–2018 recorded and 2019–2023 forecast capital expenditures for GMS.

Figure II-21
2014 – 2018 Recorded/2019-2023 Forecast Capital Expenditures for Grid Management System (GMS)[132]
CWBS Element CIT-00-SD-PM-781701
(Total Company - Nominal $000)



SCE initiated work on the GMS in 2016 and made progress in key areas, including developing high-level requirements and use cases to publish the Request for Information for the GMS, conducting a proof-of-concept for the Operational Service Bus (OSB)[133] within the control system environment, and completing lab demonstrations for the interaction between the CSP, all substation equipment, and SCE's operations centers. In 2017, SCE attempted to deploy the DERMS component but identified design and architectural deficiencies with the selected vendor product. This minor setback, however, provided valuable lessons-learned that were applied to the workstream's technology direction, including the ADMS-DERMS integration plans. Other progress in 2017 included completing the GMS Request for Information response evaluations, which provided more insights on the

[132] Please refer to WP SCE-02, Vol. 2, Pt. 1, Ch. II – Book A - pp. 165 – 166 – Capital Details by WBS for GMS.

[133] An OSB allows for integrating disparate vendor products through a non-proprietary, standards-based software integration platform.

commercially-available products, vendor partnerships, integration complexity, and more importantly the maturity levels of the product offerings. This helped inform the comprehensive GMS RFP in the latter part of 2017.

In 2018, the program focused on evaluating the RFP responses and conducting a detailed design phase with the preferred vendor prior to making the final selection. The program also developed and implemented interim control algorithms and DER constraint management functionality for use until the DERMS is deployed. SCE also procured hardware to build the necessary test environments for the initial GMS release.

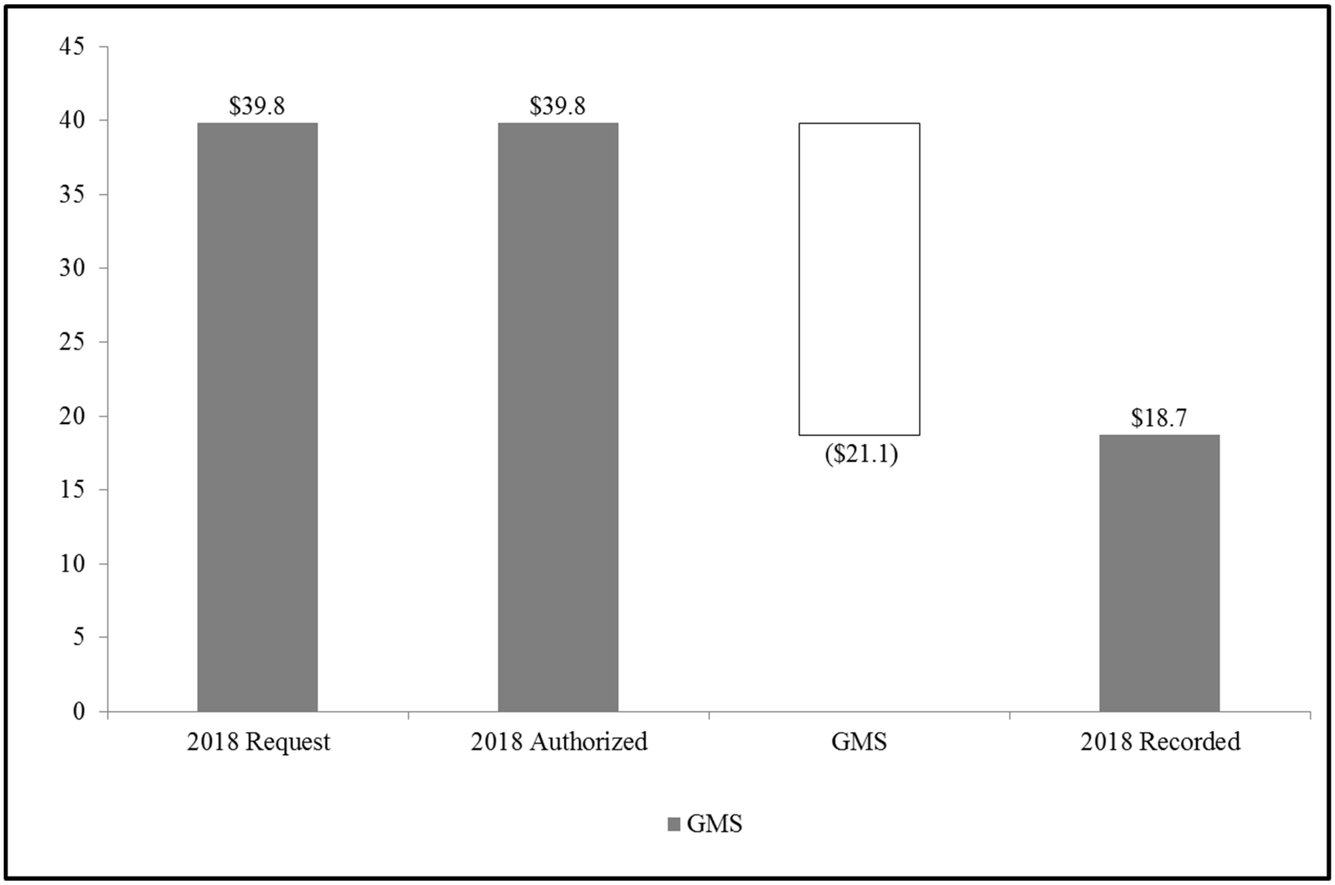
The GMS capital expenditure forecast for the 2021 GRC reflects several key developments since the initial forecast was developed for the 2018 GRC. First, due to the timing impact of the 2018 GRC Decision, SCE elected to slow-down the project initiation, which resulted in the deferral of considerable GMS-related capital expenditures. As such, the GMS costs in the 2018-2021 period are significantly below the 2018 GRC forecasted and approved amounts. Second, there were a number of learnings that helped inform the 2021 GRC forecast including the following:

- Identification of additional required scope for the Business Rules Engine (BRE) and a more robust Data Historian capability
- The need for a more comprehensive approach to system integration and system testing
- Maintenance and support costs that fell outside of the 2018 GRC forecast period are now included in the 2021 GRC forecast period

c) <u>Comparison of Authorized 2018 to Recorded</u>

The 2018 GRC Decision requires SCE to compare the 2018 authorized amounts to the recorded amounts; Figure II-22 compares these amounts for the GMS capital expenditures.

Figure II-22
Grid Management System
2018 GRC Authorized Variance Summary 2018 Capital
(Total Company - Constant 2018 $Millions)



The 2018 recorded capital expenditures for GMS were approximately half of the authorized amount. This is partially a result of the 2018 GRC Decision timing. Prior to receiving the 2018 GRC Decision SCE proceeded with limited project activities which included engaging with other large utilities to learn from their deployment efforts and gauge the availability and maturity of vendor products. SCE then conducted a competitive solicitation for the GMS solution, which highlighted the need to adjust the composition, sequence, and timing of the phased releases. Consequently, part of the GMS scope initially planned for 2018 was deferred to 2020, which further reduced the 2018 expenditures to below the authorized amount.

d) Need for Capital Program

In its 2018 GRC Decision, the Commission agreed with SCE's GMS proposal, recognizing that "GMS will provide Cybersecurity benefits, enable DERs, and integrate SCE's distribution software."[134] More broadly, various policy, technology, and operational complexity factors drive SCE's need for the capabilities enabled by the GMS. The specific investment drivers and the customer benefits SCE expects to result from the GMS capabilities are summarized below.

(a) Drivers

(i) Market Drivers

A wider array of DER choices and financing options, and declining costs continue to drive increasing customer adoption of solar PV, electric vehicles and other DERs. This higher pace of customer adoption, driven by market forces as well as California and federal policies, supports SCE's need to augment its grid operations tools and processes to consider DERs. SCE needs to understand and manage DER impacts to the grid and to use them to satisfy grid needs.

(ii) Policy Drivers

One of the Commission's principal objectives of the DRP is to provide opportunities for DERs to realize benefits by providing grid services,[135] whereby DERs may defer traditional infrastructure upgrades. To achieve this objective, SCE must have a high degree of confidence that the DERs—which SCE contracts with via the DIDF process—will be available for dispatch when needed. If the DERs are unavailable when grid needs arise, this may expose the grid to reliability risks.

SCE's planning process attempts to identify the season and time of day when grid needs are expected to arise; but real-time weather conditions have more influence over grid needs. The GMS will provide SCE system operators and operations engineers with real-time visibility and control of the DERs that SCE has contracted with to provide grid services. The GMS's DER management capabilities will also enable SCE to implement the IEEE 2030.5 communication protocol. This standard supports DER communications (either directly with DERs or through an aggregator), including DER interconnections governed by SCE's Tariff Rule 21, which will enable the use of DERs to provide grid services. This protocol can be used to provide DER performance

---

[134] D.19-05-020, p. 115.

[135] Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resources Planning, dated February 6, 2015, in R.14-08-013, p. 3.

information to system operators and enable DERs to provide grid services, as may be allowed or directed by the Commission.

(iii) Technology Drivers

SCE's DMS has been discontinued by the vendor and product enhancements are no longer supported. The system is therefore obsolete, as evidenced by its multiple hardware failures over the last few years. The DMS is also incapable of supporting the enhanced application-level security needed to mitigate emerging cyber threats. SCE's OMS also requires several improvements, including distribution outage management workflows and enabling quicker response times for outage remediation.

(iv) Operational Complexity Drivers

While DERs bring many types of benefits to customers and to the grid, they also create new operational challenges. These challenges stem from the limited information available to system operators about real-time grid conditions and their limited level of control. This level of information and control was sufficient when power was delivered to each circuit from a single source. It will be inadequate when substantial amounts of generation emanate from multiple sources within a particular circuit, since operators will be unaware of power flow levels and their direction within the circuit. This lack of information will make it difficult to understand the impacts of potential switching operations and will hinder recovery from unplanned outages. SCE's experience with DER-based demonstrations and increased DER adoption—both SCE and 3rd party-owned—confirms that the DMS and OMS are inadequate for managing the grid with higher DER levels. A DERMS is needed to manage and dispatch DERs optimally to provide grid services (to facilitate non-wires alternatives) and enable DERs to participate in energy markets when not needed for grid services.

(b) Benefits

(i) Safety

The improved telemetry and switching capabilities provided by SCE's modern distribution automation approach, when paired with the GMS, will improve SCE's ability to monitor and respond to real-time conditions on the distribution system. This will enable SCE to mitigate potential safety hazards more quickly, reducing the potential for customer and workforce exposure to such hazards. Since modern distribution automation will reduce the number of customers impacted by outages, outage frequency, and outage duration, customers responsible for maintaining the safety, security and health of customers living in SCE's service territory will experience fewer and shorter periods without electric service. These distribution automation capabilities therefore provide an indirect safety benefit.

The GMS is critical to enabling this distribution automation benefit since it will provide visibility and situational awareness to system operators, inform them about potential abnormal grid conditions and assist with avoiding them, and help to resolve abnormal conditions that actually occur. The GMS will provide substantial improvements with the distribution automation already deployed and will realize additional benefits with the distribution automation proposed in the 2021 GRC. The GMS's automatic high-impedance fault detection capability will also reduce potential customer exposure to fallen wires.

(ii) Reliability

The GMS will eliminate a substantial share of momentary and sustained outages for customers on circuits with modern distribution automation enhancements—including enhancements made prior to the 2021 GRC period. The GMS will provide visibility and situational awareness to system operators and inform them about potential abnormal grid conditions. The GMS will assist system operators with avoiding outages and help to resolve abnormal conditions that actually occur.

(iii) Wildfire Resiliency

By enabling high-impedance fault detection, the GMS will be able to identify fallen conductor and automatically de-energize the affected circuit segment. GMS will be able to reduce Meter Alarming of Downed Energized Conductors (MADEC)[136] operation time by minutes. This reduces the potential risk of fallen, energized conductor being a source of wildfire ignition.

(iv) Decarbonization

By providing system operators with granular circuit segment data collected by modern distribution automation devices, the GMS will help enable SCE to optimize the use of DERs to provide grid services. To the extent this increases DER penetration, there will be a reduced need for incremental GHG-emitting resources. The GMS is foundational to enabling

---

[136] Meter Alarming of Downed Energized Conductors (MADEC) is a wire-down detection application developed by SCE which leverages the AMI data to detect down energized wire and high impedance. A high-impedance fault results when an energized primary conductor comes in contact with a quasi-insulating object such as a tree, structure or equipment, or falls to the ground. These types of faults generally are not detected by conventional protective devices (i.e. circuit breakers, circuit automatic reclosers and branch line fuses).

this benefit since it will function as the central location for collecting circuit data and analyzing circuit conditions. It will also recommend and/or perform switching operations to increase DER utilization and use DERs to address grid reliability concerns.

(v) Customer Empowerment

By collecting and analyzing the enhanced telemetry information provided by distribution automation devices, the GMS will help to integrate higher amounts of DERs on targeted distribution circuits. This will empower customers with cleaner energy choices.

(vi) Economic Efficiency

The LTPT-SMT section of this testimony describes how increasing the granularity of SCE's system planning analysis capabilities will enable SCE to analyze and validate projects driven by planning and forecasting assumptions, which could better define the SCE's forecasted grid needs. This has the potential to increase the accuracy of the timing and sizing of infrastructure projects—whether it includes traditional grid infrastructure or DERs. The GMS is foundational to enabling this benefit since it will function as the central location for collecting circuit data and analyzing circuit conditions. It will also recommend and/or perform switching operations to increase the use of DERs to address grid reliability concerns—consistent with the needs identified in the grid planning process.

e) Basis for Capital Expenditure Forecast

SCE based the revised GMS capital expenditure forecast of $191.9 million on an extensive RFP effort, which included a design phase, close interaction with the preferred vendor, and visits with other utilities that have already deployed the same solution.[137] The capital expenditures will therefore follow a phased approach that prioritizes the most immediate needs and implements capabilities gradually to minimize deployment risks. Following detailed planning, design, and negotiations with the selected vendor, SCE derived the capital forecast based on the following key project phases:

- Phase 1: Distribution SCADA upgrade
- Phase 2: Base ADMS platform implementation
- Phase 3: Advanced ADMS and DER management capabilities

[137] Utilities SCE visited include Duke Energy, Alabama Power, and Pennsylvania Power & Light (PPL).

The GMS will follow a standard system engineering lifecycle methodology. The cost elements will encompass project management, system planning, system design and configuration, hardware and software procurement, testing, and finally the roll-out in SCE's production environment. The revised GMS capital forecast reasonable and justified given that it is based on competitive market pricing. The GMS capital forecast includes project team costs for SCE employees, supplemental workers, consultants, software, hardware, and selected vendor costs.[138]

4. Capital Expenditures for Automation

a) High-level Program Description

In SCE's 2018 GRC testimony, SCE presented the need, vision and plan to augment its automation capabilities to address reliability challenges on its worst performing circuits and to help integrate higher amounts of DERs. In alignment with the Commission's 2018 GRC Decision, SCE remains committed to implementing automation-based capabilities that address reliability and safety performance while also enhancing SCE's ability to integrate DERs into the distribution system. This commitment resulted in the successful deployment of modern automation on 73 circuits in 2018, and completion of thirteen SA-3 substations in 2018 and 2019. Due to significant intervenor opposition to SCE's proposed automation scope and scale, SCE concentrated a lower level of automation deployments toward improving reliability on a smaller number of circuits than SCE proposed in the 2018 GRC, performing no automation for DER-driven needs.

In the 2021 GRC, SCE proposes to continue these deployments at a more limited scope and pace due to a necessary and temporary reallocation of resources to mitigate wildfire risk. SCE faces severe labor resource constraints due to the concurrent need for wildfire resiliency engineering, planning, and deployment activities. Given the criticality of SCE's wildfire resiliency efforts, SCE has reprioritized these resources toward those efforts. As the wildfire resiliency activity subsides, SCE plans to shift additional labor resources to fully resume the distribution automation deployments. Accordingly, SCE plans to perform Reliability-driven Distribution Automation on 225 circuits and DER-driven Distribution Automation on 72 circuits from 2021 to 2023, nearly half the number requested for 2018 to 2020 in the 2018 GRC.[139]

---

[138] Please refer to WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A - pp. 167 – 168 – GMS Capital Workpaper.

[139] Please refer to WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A - pp. 169 - 175 – Reliability-driven Distribution Automation Forecasts.

For each Reliability-driven Distribution Automation circuit, SCE will add up to one intelligent automated switch[140] with fault interrupting capability, one remote-controlled switch (RCS) with telemetry for a circuit tie, five remote fault indicators (RFIs), and one upgraded circuit tie. SCE expects these distribution automation deployments will reduce CMI by 34.15 million[141] annually by 2023. Based on SCE's BCA, this will provide SCE's customers with reliability benefits that exceed the cost by a factor of nearly seven.[142] Since the BCA only analyzes the reliability benefits of these investments, the BCA is conservative. Other benefits expected to result from these investments, but which are not quantified in the BCA, include safety, decarbonization, and economic efficiency.

In the 2021 GRC, SCE is introducing Small-scale Deployments to perform limited post-demonstration deployments of distribution automation components. These limited deployments will occur prior to deploying large quantities of the technology to all geographic regions. This will ensure that SCE can deploy the devices throughout its service territory, helping to improve SCE's overall deployment planning and execution. SCE is currently evaluating multiple RFI solutions, including underground, pad mounted, and low-current devices.

In the 2021 GRC, SCE will not request funds for additional substation automation deployments for the Reliability-driven SA-3 considered in the 2018 GRC. However, SCE will request funding for Reliability-driven SA-3 deployments completed through mid-2019.

In the 2021 GRC, SCE is also introducing new DER-driven SA-3 focused on substations impacted by DER growth. The full implementation of SA-3 proposed in both Reliability-driven SA-3 and DER-driven SA-3 includes a CSP with WAN connectivity. The full implementation of

---

140 Resolution E-4982, Attachment B, p. 35, defines Intelligent Automated Switches as an example of hardware that can perform Fault Location Isolation and System Restoration (FLISR) and the classification tables include Remote Intelligent Switches, Augmented Remote Control Switches, Automatic Reclosers, and RCS retrofits as examples of these technologies. SCE's design includes switches similar to Automatic Reclosers wherever possible under this definition including the Remote Intelligent Switch and other fault interrupting switch types.

141 Please refer to WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A - pp. 169 – 175 – Reliability-driven Distribution Automation Forecasts. Benefit Cost Analysis Results. A more advanced cost benefit analysis that also includes the reduction of stress on equipment as a result of interrupters installed under this program is planned to be performed but was not available at the time of writing.

142 Please refer to WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A - pp. 169 – 175 – Reliability-driven Distribution Automation Forecasts. Benefit Cost Analysis Results.

SA-3 is critical to providing the CSP's full cybersecurity functionalities.[143] The GMP in Appendix A provides additional information about SCE's anticipated future SA-3 needs.

The Automation workstreams are presented in the following order:

- Reliability-driven Distribution Automation
- DER-driven Distribution Automation
- Small-scale Deployments
- Reliability-driven Substation Automation (for deployments through mid-2019)
- DER-driven Substation Automation

Recovering from distribution system outages has historically been enabled by (1) substation automation systems (SA), including the first generation (SA-1) and, (2) to a lesser extent, historical distribution automation[144] devices such as RCSs. SA-1 relays do not provide directional power readings and therefore cannot distinguish between generation and load. SA-1 substations, therefore, need to be upgraded in areas with high DER penetration. The historical distribution automation devices also lack modern telemetry[145] and provide insufficient situational awareness to monitor and control distribution circuits, particularly ones with high levels of DERs.

Traditionally, the distribution grid operated as a one-way system. This system has provided system operators with limited capabilities to remotely monitor and control distribution substations and little to no ability to control distribution circuits. Automation provides system operators

---

[143] As part of its CSP implementations and other cybersecurity work, SCE has identified a need to proactively upgrade some SA-1 and SA-2 substations to introduce cybersecurity hardware and tools like those provided by the CSP. As of filing, this work is called CSP lite. The CSP lite is not compatible with SA-3. *See* Section of this Chapter above on Common Substation Platform providing further information on the plan to deploy cyber-secure substation hardware apart from the SA-3 program, in this 2021 GRC.

[144] Historical distribution automation is only capable of actuating by manual over the air command or is automatic based on loss of voltage. Notably missing in historical distribution automation are directional power and current measurements, which are critical to managing the two-way power flows associated with higher DER penetration.

[145] Modern telemetry gathered using grid sensors includes real-time data such as current (by phase), voltage (by phase), directional real power, directional reactive power, power factor, voltage outside acceptable limits alarming or actuation, and directional fault indication. Modern telemetry provides a window into the state of the distribution feeder and helps to identify potential grid reliability or power quality issues–including ones caused by DERs. While SCE's definition of modern telemetry does not include phasor measurement units (PMUs), another type of grid sensor, it may do so in future GRCs.

with additional visibility, situational awareness,[146] and control. With increasing DER adoption, these capabilities will help ensure that the resulting bi-directional power flow, masked loads, resource variability, and other DER integration challenges do not cause undetected operating hazards. Automation will increase the grid's ability to respond to dynamic grid conditions to maintain reliability. Pairing automation with SCE's GMS would enable DERs to provide services to SCE's distribution system, increasing the value of DERs.

(1) Historical Distribution Automation

Beginning in the 1990s and continuing through 2017, SCE deployed an effective, but limited, system of distribution automation to reduce the reliability impacts of circuit problems such as faults. This historical distribution automation approach restored service to up to 50% of a circuit's customers following an outage. These customers would still experience a momentary outage but would avoid a longer-duration sustained outage.[147] While helpful in reducing sustained outages for some customers, the historical approach does not meet the needs of a dynamic grid with multiple potential power sources since it has no monitoring from grid sensors.

The historical distribution automation system also requires manual configuration to function properly. SCE must dispatch a qualified electrical worker to drive to the substation to configure the substation automation. SCE must also dispatch a qualified electrical worker trained in distribution equipment to drive to the single RCS at the midpoint of a given distribution circuit and change its settings to enable the automation. Finally, SCE engineers and system operators must evaluate these systems on an ongoing basis to both enable and disable the automation manually as operating conditions change. Historical automation, since it lacks internal intelligence to adjust settings for changing operating conditions, had to be removed from service manually for maintenance, repair, or during emergencies. SCE reviewed its distribution automation and substation records in 2017 and found that the automation on some of its circuits had not been manually restored to service. This was potentially due to the work process including manual data entry in multiple systems, which increases the

---

[146] Situational awareness represents human comprehension of the information necessary to perform an action. Data from SCADA devices and grid sensors is first provided to the operational systems, such as the ADMS, which provide visibility to the system operator. The system operator must then assess the available information. After assessing the information, the system operator has become situationally aware of any changes necessary to avoid a potential problem or react to an actual problem.

[147] Service interruptions lasting less than five minutes are called momentary outages while interruptions lasting five minutes or longer are called sustained outages.

risk of human error. These issues have since been mitigated partially through improved work-management efforts that allow system data synchronization. However, the improved process still must be initiated, completed, and verified manually. The remote configuration capabilities of SA-3, along with the improved flexibility of SCE's intelligent automated switch designs, is expected to prevent these issues by enabling automatic digital extraction of the data from relays, which eliminates manual records management activities.

The historical distribution automation system has only been implemented with up to one midpoint switch due to the reliance on circuit breaker testing and measurements to inform RCS switching following a fault. Under fault conditions, replicating the traditional test and measurement sequence with more than one midpoint RCS would require additional testing of each midpoint RCS. This additional testing would introduce additional high-current impulses through the cable, adding thermal stress to the cable insulation.[148] This would introduce undue asset health and safety risks, particularly to underground cable, which cannot be inspected visually. SCE's proposed modern distribution automation does not increase cable or conductor stress. Rather, it reduces or eliminates the need for this kind of testing—by providing more measurements along the circuit to identify the fault location, and in some instances by interrupting the fault current.

(2) Modern Distribution Automation

Starting in 2017, SCE began implementing a modern distribution automation design that adds more intelligent automation devices beyond a circuit source,[149] including fault interrupting switches[150] to create additional circuit segments within a distribution circuit.[151] This also includes installing RCSs at circuit tie[152] locations to provide flexibility to transfer[153] circuit

---

[148] Thermal stress risks for cable are described in SCE-02 V. 1.

[149] Source in this context typically refers to the source of electric power on a distribution circuit, measured at the substation breaker. The substation circuit breaker share of source decreases as the level of DER penetration increases.

[150] A switch is a device capable of dividing contiguous circuit segments.

[151] A circuit segment is a section of energized conductors between switches capable of receiving and delivering power.

[152] A circuit tie is a switch location whereby a circuit segment can be energized temporarily from another source during emergency events or planned maintenance.

[153] A transfer is a switching operation which uses a circuit tie. SCE performs approximately 12,000 operations each year.

segments during outage events or moments of DER-driven congestion.[154] This may also include circuit tie upgrades where there is a low likelihood an adjacent circuit could receive the circuit segment load or generation safely.

The modern distribution automation design also includes improved sensors and communication devices needed to manage local distribution circuit needs. The increase in switches, sensors and associated real-time circuit data will provide system operators and GMS operations algorithms[155] with greater visibility. This will improve the potential switching options during abnormal conditions. The increase in fault interrupting switches, sensors, and associated real-time circuit data would also reduce the need for testing. On circuits with modern automation, SCE would not need to perform testing by opening and closing the substation circuit breaker and midpoint RCS to isolate faults. This would avoid adding stress to distribution system equipment and increasing asset health risks.

Modern distribution automation, together with the GMS, will be able to: (1) provide system operators the flexibility to safely isolate faults, (2) safely restore additional customers more quickly following a fault, (3) reduce the number of customer outages, (4) measure load and DER behavior, and (5) manage groups of DERs. Modern distribution automation will help to enable system operators to overcome masked load and DER variability concerns to safely manage a system with high DER penetration. The data collected by modern distribution automation and SCE's AMI[156] system will further enable system planners to identify opportunities and locations to consider DERs in lieu of traditional expenditures.[157]

SA-3 will enable communication and enhance the cybersecurity of SCE's substation equipment when deployed in conjunction with the CSP and WAN. SA-3 enables SCE to change critical substation safety settings using cyber-secure, internet-based communications. These communications enable SA-3 substations to communicate directly with distribution equipment for faster response to outage and safety issues. These communications also enable two-way data exchange

---

[154] Congestion is a condition where energized conductors are nearing their operating limits, and small changes in the circuit can lead to overloads and potentially outages.

[155] An algorithm is a computer process that under certain rules can execute a specific function, in this case, remote distribution automation device switching.

[156] SCE uses SmartConnect meters that provide interval data on customer energy use that can be harvested and analyzed the day after the measurements are taken to inform planning.

[157] Telemetry from modern distribution automation helps system planners better understand grid needs and therefore the Reliability-driven Distribution Automation technology supports this decision.

between SA-3 substations and SCE's central IT systems through the CSP. SA-3 will also enhance the ability of substations to communicate critical safety settings and detailed event history through SCE's IT systems with the GMS. Detailed event history and settings information is critical for the GMS and system operators to respond to outages.

SA-3 will also support flexible substation device settings changes through implementation of International Electrotechnical Commission (IEC) 61850, an international standard designed for integrated control and monitoring of DERs from substations and control centers. The CSP secures these communications.

SCE expects to continue deploying modern automation on its worst performing circuits, which will reduce sustained customer outages by 50-75%[158] on those circuits. As a result, SCE expects that the improved reliability performance on circuits with modern distribution automation will reduce the overall system average interruption duration index (SAIDI) by up to 7 min[159] by 2021. Circuits with modern distribution automation will experience greater reliability and safety and will be able to host more DERs safely and reliably.

Table II-17 summarizes the two high-level capabilities that SCE expects the Automation workstreams to enable.

---

[158] Please refer to WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A - pp. 169 – 175 – Reliability-driven Distribution Automation Forecast. Consistent with the approaches discussed in SCE's 2018 GRC showing, one to three midpoint switches and one to three tie switches (3-3) were installed on circuits with high contribution to SAIDI. SCE installed a blend of interrupting and non-fault interrupting switches in the 2017 to 2020 period. In this 2021 GRC, SCE has limited its request by adding one additional midpoint intelligent automated switch with fault interrupting capability (or RCS) and one limited circuit tie upgrade along with a tie RCS (+1/+1).

[159] Please refer to WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A - pp. 169 – 175 – Reliability-driven Distribution Automation Forecasts. Excludes incremental benefits expected from ADMS and FAN. SCE still sees value in considering IEEE 1366 classified Major Event Days or MEDs in its SAIDI improvement figures since it better reflects customer experience, but no longer includes MEDs in its estimates given the opposition to the use of the metric from intervening parties in the 2018 GRC. SCE's automation investments have positive BCR using either metric.

Table II-17
Automation-supported Capabilities

Capability Categories	High-level Capabilities
Automation Improves grid monitoring and control using real-time telemetry directional power flow data	a. Grid condition data collection and awareness b. Automatic execution of grid reliability issue mitigations

b) <u>Summary of Cost Forecast</u>

Table II-18 summarizes the 2014–2018 recorded and 2019–2023 forecast capital expenditures for Automation.

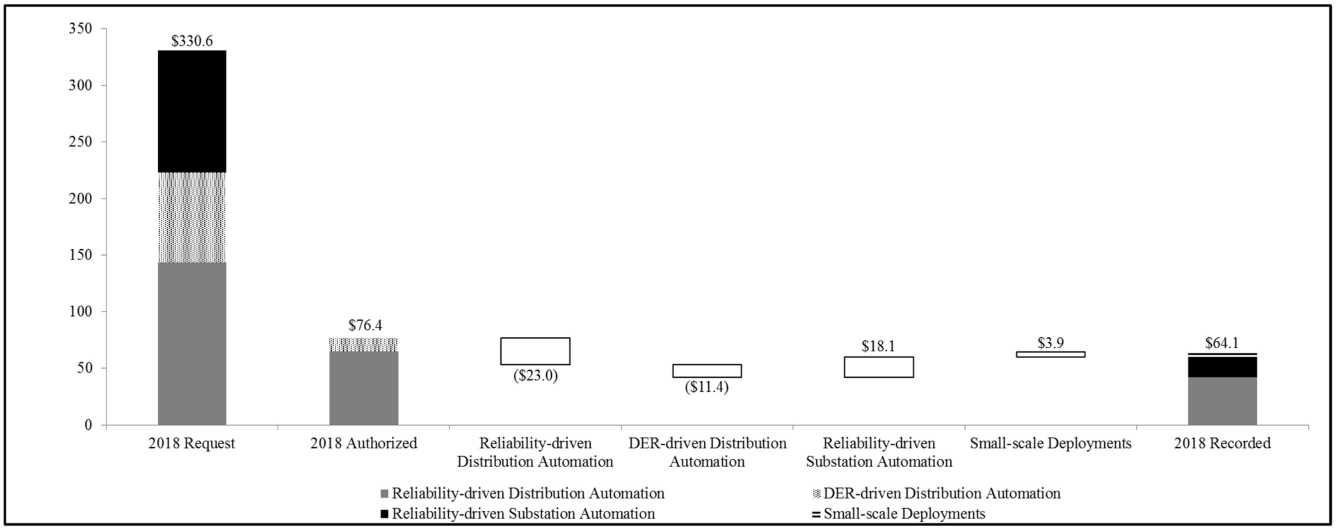
Table II-18
Automation Capital Expenditure Summary
Recorded 2014-2018/Forecast 2019-2023
(Total Company - Nominal $000)

	Recorded					Forecast				
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Reliability-driven Distribution Automation	$6,090	$7,141	$10,465	$17,817	$42,011	$61,526	$34,809	$23,872	$25,141	$25,356
DER-driven Distribution Automation							$590	$1,026	$843	$970
Small-scale Deployment		$374	$1,112	$10,207	$3,938	$5,171	$7,633	$7,146	$5,599	$5,326
Reliability-driven Substation Automation		$248	$8,744	$19,966	$18,131	$6,701				
DER-driven Substation Automation								$4,000	$7,828	$5,965
Automation Totals	**$6,090**	**$7,763**	**$20,321**	**$47,990**	**$64,081**	**$73,398**	**$43,032**	**$36,044**	**$39,411**	**$37,617**

c) <u>Comparison of Authorized 2018 to Recorded</u>

Figure II-23 below compares 2018 authorized amounts to the recorded amounts for Automation capital expenditures.

Figure II-23
Automation[160]
2018 GRC Authorized Variance Summary 2018 Capital
(Total Company - Constant 2018 $Millions)



The Commission's 2018 GRC Decision authorized expenditures above the recorded amounts for SCE's Automation activities. Recorded expenditures for both Reliability-driven and DER-driven Distribution Automation are lower than the Commission-authorized amounts due to a number of challenges.[161] For example, the 2018 GRC Decision timing provided SCE with no ability to modify its deployment activities in 2018. Additionally, delays in training associated with new equipment deployments also affected 2018 deployments. Emergent efforts to support wildfire mitigation and the associated resource reprioritization to support this work[162] reduced SCE's distribution automation deployments in 2019 due to labor resource limitations.

The Commission authorized SCE's SA-3 funding request of $46.418 million for 2017 but denied funding for 2018 through 2020. SCE incurred capital expenditures for 15 SA-3 projects initiated in 2017 and completed in 2018 and 2019, as illustrated in Figure II-23. In anticipation of the

---

[160] Please refer to WP SCE-02, Vol. 2, Pt. 1, Ch. II – Book A - pp. 119 - 120 – Grid Modernization Authorized to Recorded Details.

[161] D.19-05-020, Conclusion of Law 44.

[162] This effort is described in SCE-04, Volume 5 – Wildfire Management.

2018 GRC Decision, SCE proceeded with some limited deployments in 2018 and 2019 that would provide customer benefits.[163] The SA-3 projects with capital expenditures from 2017 through 2019 are now used and useful.

Through July 2019, SCE has recorded no capital expenditures for DER-driven Distribution Automation and forecasts spending less than authorized in the 2018-2020 period. SCE also has more confidence in its DER planning process than in 2016, due in part to tools developed for ICA. In 2016 and 2017, SCE had limited experience with these types of DER forecasts and studies and its tools were still evolving. The extensive opposition to SCE's DER forecasting approach during the 2018 GRC introduced financial risk to SCE's DER-driven activities. SCE therefore prioritized expenditures on circuits with existing reliability concerns.

d) <u>Need for Capital Program</u>

Market and technology factors drive SCE's need for the capabilities enabled by Automation. The specific investment drivers and the customer benefits SCE expects to result from the Automation capabilities are summarized below.

(a) <u>Drivers</u>

(i) <u>Market Drivers</u>

A wider array of DER choices and financing options, and declining costs continue to drive increasing customer adoption of solar PV, electric vehicles and other DERs. This higher pace of customer adoption, which is driven by market as well as California and federal policies, is driving SCE's need to augment its distribution and substation automation capabilities on circuits forecasted to have high-DER penetration. Modern automation capabilities will arrest the reliability degradation associated with DERs and support DER integration.

(ii) <u>Technology Drivers</u>

a. <u>Reliability-driven Distribution Automation</u>

There are two broad categories of distribution customer outages that drive SCE's reliability programs: (1) equipment failures, which are considered

---

[163] *See* section on Reliability-driven Substation Automation for additional detail on SA-3 expenditures.

preventable by infrastructure replacement (IR), and (2) uncontrollable.[164] SCE has two primary programs to reduce the frequency and duration of both kinds of outages: (1) Distribution IR[165] and (2) Reliability-driven Distribution Automation. While IR can reduce the frequency of preventable outages, distribution automation is designed to address uncontrollable outages, hasten outage response, and mitigate outages related to DER integration challenges.[166] Because almost half of sustained outages are uncontrollable, SCE needs additional modern distribution automation to realize any improvement in customer experience during uncontrollable outages. Additionally, distribution automation can also reduce the impacts of equipment failures. While the need for additional study remains, preliminary evidence suggests that modern distribution automation devices capable of fault interruption may reduce certain cable failure risks.

To support the 2018 GRC, SCE studied its historical distribution automation programs and reliability records and demonstrated that reliability can be improved with historical distribution automation, even for uncontrollable outages.[167] SCE determined that distribution automation work performed in 2017 alone reduced SAIDI by 1.25 minutes in 2018.[168] By installing additional modern distribution automation on SCE's worst performing circuits and on circuits with the highest potential for reliability improvements, Reliability-driven Distribution Automation is expected to provide meaningful reliability improvements.

---

[164] Uncontrollable outages result from factors beyond SCE's control, such as a car hitting a pole or underground cable dig-ins from 3rd parties. Uncontrollable outages cannot be avoided by traditional utility maintenance or capital upgrade activities.

[165] SCE-02 V. 1, Distribution Infrastructure Replacement.

[166] Resolution E-4982, in Attachment C, Section F, specifies that DER integration challenges include: 1. Voltage Fluctuation, 2. Steady-State Voltage Violations, 3. Masked Load, 4. Thermal, 5. Protection, 6. Operational Limitations, 7. Fault Location and Service Restoration, 8. Energy Market Security, 9. Cybersecurity, 10. DER Aggregation Impacts on the Bulk Grid, 11. DER Wholesale Market Participation.

[167] *See* 2018 GRC Testimony, SCE-02, Vol. 10 pp. 43-44 "In 2010, SCE automated 321 distribution circuits. The average SAIDI for these circuits over the period 2007 – 2009, prior to automation, was 166.7 minutes. After automation, the average SAIDI for these circuits over the period 2011 – 2013 was 149.4 minutes, a reduction of 10%."

[168] SCE review of historical outages in 2018 indicated that work in 2017 and 2018 on existing and new automation improved SAIDI performance during outages where automation was used by 1.25 min in 2018.

b. DER-driven Distribution Automation

Unlike the modern distribution automation being deployed today, the historical distribution automation approach provided no visibility of individual circuit segment loading and other information useful to understand system power flows. The distribution system was therefore not well-suited to integrate DERs. When DERs begin to congest circuit segments, the data typically provided by the historical design is insufficient for operators to evaluate circuit operating conditions with two-way power flows. This problem is called "masked load" and is one of the DER integration challenges identified in the DRP Track 3, Sub-Track 2.[169] For example, without knowing the power flow direction, an operator may be unable to determine the need for corrective actions to prevent thermal overloads. Additional operator study time to evaluate the status of these DER sources to address the safety of an emergent reconfiguration need could delay service restoration following an outage. Without modern distribution automation and the GMS, circuits with high DER penetration might experience up to 45 minutes of additional switching time with every mainline outage (i.e., the outage will be 45 minutes longer than it would be in the absence of the DERs).

To estimate this additional switching time, SCE examined several anecdotal examples to understand the potential impacts of high amounts of DERs on outage responses. These examples are not intended to be an exhaustive list of DER-related reliability issues since many outages have secondary or tertiary causes.[170] In each documented case, neither the system operators nor the operations engineers used the aggregated, prior-day AMI data to inform switching operations. System operators and operating engineers prefer real-time data from field devices over previous-day, aggregated AMI energy data, since real-time device data reflects current operating conditions. System operators were also unable to visualize whether DER power flows influenced the circuit's problems. As a result, in many of these examples the operations engineers had to perform a study to evaluate whether masked load, generation output, and/or generation variability would prevent a safe switching procedure. Without this detailed study, extended outages for many customers could occur when a transfer is performed that results in an overload from masked load or excessive DER generation.

---

169 D.18-03-023, Appendix C, pg. 8 "With DER generation, the utility may only see net load, and may be unaware of the true load on each circuit. In situations where lines may have to be de-energized and then re-energized, such as a fault on the circuit, the utility must manage the true load without the assistance of DERs that have not yet been activated. This is in addition to cold load pick up, which is a situation where certain devices require a spike in load at start up, i.e. induction motors, air conditioners, etc."

170 Please refer to WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A - pp. 176 – 177 – DER Impacts to Operations.

DER-driven Distribution Automation expenditures help address the challenges of masked load and DER variability and support DER integration. As discussed at length in the 2018 GRC and oral arguments, SCE's current AMI architecture does not support real-time energy use data retrieval and it would be costly to modify the AMI system to enable this.[171] SCE is therefore expanding its network of grid sensors, primarily through RFI installations, to provide real-time circuit data to system operators.

c. Small-scale Deployments

To ensure that technology deployments are successful and operate as intended once deployed, it is critical that SCE perform small-scale deployments prior to system-wide deployment. Small-scale Deployments will help to verify that the distribution automation components operate properly once deployed. In addition to validating technical performance, small-scale deployments provide an opportunity to evaluate planned stakeholder communications, training, material codes, and standards.

d. Reliability-driven SA-3

SA-1 is an obsolete technology and the manufacturer no longer supports many of its components. Replacement parts are unavailable from the manufacturer and are difficult to procure elsewhere. Additionally, the SA-1 substations deployed prior to 2003 continue to experience high relay failure rates. SCE expects the SA-3 substations will eliminate this reliability and safety challenge.

The SA-1 substations' obsolete distribution protection relays also cannot monitor reverse power flow, which is critical for safe and reliable DER integration. The SA-3 substation design provides standards-based networking and interoperability between substation devices. SA-3 fully supports IEC 61850 functionality which allows for adapting to DER interconnections quickly. Because the SA-3 platform will improve SCEs ability to quickly interconnect DERs, SCE expects substations with this functionality will reduce or eliminate potential barriers to DER interconnections.[172]

---

[171] A. 16-09-001, Evidentiary Hearing Transcript, Vol. 13, p.1764, "the best estimate we would have is $1.6 billion."

[172] DERs change the electrical characteristics of the system. From time to time protection settings must be changed to accommodate DERs. This need is identified during the interconnection study phase of SCE's Tariff Rule 21 process. In most cases, the cost to perform the studies and update settings is borne by the

e. DER-driven SA-3

As described in the preceding Reliability-driven SA-3 section, SA-1 is an obsolete technology and the manufacturer no longer supports many of its components. SA-1 was not designed to accommodate two-way power flows and cannot determine whether a distribution feeder is back-feeding from DERs or delivering power to customers. SA-1 is therefore not well-suited to integrate DERs.

Today, SCE can only adjust protection and safety characteristics on a circuit (driven by DER generation) by manually preparing system protection studies and then traveling to SCE substations (often located in remote areas) to update protection settings. This process can take weeks to months depending on the severity of the issue. In addition, a multitude of DER interconnections and the resulting system reconfigurations could make it harder for SCE's personnel to adjust settings in a timely manner, which could impact interconnection times.[173] The lack of power flow direction data provided by older generations of substation equipment such as SA-1 could confuse the GMS power flow model and potentially cause its load allocation features to stop functioning. Therefore, the GMS alone cannot overcome these challenges.

SA-3 enables the ability to safely and remotely reprogram circuit breaker settings to accommodate DERs without requiring personnel to visit the substation. This could impact customer interconnection costs as the number of DER interconnections increases. SA-3 supports the ability of substations to quickly adjust protection settings to accelerate interconnection times through standardized communication protocols, which allow substation protection systems to be adjusted remotely to address changing system characteristics.

(b) Benefits

(i) Safety

The improved telemetry and switching capabilities provided by SCE's modern distribution automation approach will improve SCE's ability to monitor and respond to real-time conditions on the distribution system. This will enable SCE to mitigate potential safety hazards more quickly, reducing the potential for customer and workforce exposure to such

---

interconnection customer. In addition, in many cases the interconnection is delayed by the time needed to manually update protection settings in the substation.

[173] Please refer to WP SCE-02, Vol. 4, Pt. 2, Ch. II – Book A - pp. 14 – 29 – High Distributed Energy Resources Planning Assumptions.

hazards. Moreover, since modern distribution automation will reduce the number of customers impacted by outages, outage frequency, and outage duration, customers responsible for maintaining the safety, security and health of those living in SCE's service territory will experience fewer and shorter periods without electric service. This provides an indirect safety benefit.

Reliability-driven Substation Automation replacement of SA-1 relays will result in a substantial reduction of unplanned customer outages caused by premature relay failures. DER-driven Substation Automation replacement of SA-1 relays will enable the substations to monitor for reverse power flow and dynamically adjust protection settings. This will reduce the number of improper substation circuit breaker operations and improve reliability. Similar to distribution automation, this will also provide an indirect safety benefit by reducing the outage frequency and duration of customers responsible for maintaining the safety, security and health of those living in SCE's service territory.

(ii) Reliability

When paired with modern control systems, such as ADMS, modern distribution automation may eliminate up to 30% of momentary outages and up to 75% of sustained customer outages on circuits with the modern distribution automation.[174]

The SA-1 relays have a record of failing prematurely while in-service. Replacing these SA-1 relays with new SA-3 relays will reduce the number of in-service relay failures and improve reliability. Replacing the SA-1 relays will also allow SCE to monitor reverse power flows, which will improve reliability on high DER penetration circuits.

(iii) Decarbonization

The granular circuit segment data collected by the modern distribution automation devices will support system planners in identifying more opportunities and locations to consider deferral or avoidance of traditional grid infrastructure investments with DERs. This granular circuit data will also help enable SCE to optimize the use of DERs to provide grid services. To the extent this increases DER penetration, there will be a reduced need for incremental GHG-emitting resources.

---

[174] Please refer to WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A - pp. 169 – 175 – Reliability-driven Distribution Automation Forecast.

By improving reliability, SCE's distribution automation will also reduce GHG emissions. The CEC performed a study[175] that indicated most customers with backup energy systems are not using clean forms of energy generation. Therefore, SCE's programs that enhance reliability also help advance California's GHG reduction goals—since customers will have less need to use back-up systems that produce GHG emissions.

(iv) Customer Empowerment

By helping to integrate higher amounts of DERs on targeted distribution circuits through DER-driven Distribution Automation, enhanced telemetry will empower customers with cleaner energy choices.

(v) Economic Efficiency

Deploying intelligent automated switches capable of interrupting fault current will reduce the number of times a distribution feeder must open and close its circuit breaker to test for the fault location during outage events. These test operations contribute to cable risks by subjecting cables to high current.[176] Reducing these operations should reduce the costs of more frequent replacement of these grid assets. This could also potentially improve the performance of customer DERs—since fewer losses of voltage will mean fewer interruptions to DERs feeding power back to the grid.

Enabling grid integration of higher amounts of DERs through DER-driven Distribution Automation will potentially defer traditional grid infrastructure investments. Increasing the options for addressing grid needs could potentially result in lower cost solutions.

e) Reliability-driven Distribution Automation

(1) Program Description

Reliability-driven Distribution Automation, referred to in the 2018 GRC as Worst Circuit Rehabilitation (WCR)-Enhanced Distribution Circuit Automation includes: (1) intelligent automated switches, (2) RCSs with integrated grid sensors, (3) RFIs, and (4) circuit tie

[175] Miller, J. W., and J. Lents. 2005. Air Quality Implications of Backup Generators in California. Volume Two: Emission Measurements from Controlled and Uncontrolled Backup Generators. University of California, Riverside, for the California Energy Commission, PIER Energy Related Environmental Research. CEC-500-2005-049.

[176] Please refer to SCE-02, Vol. 1. Distribution Infrastructure Replacement.

additions or enhancements. As an alternative to continuing to augment only the WCR circuits[177] with additional automation, SCE may enhance this strategy in the 2021 GRC by also automating circuits that generally have poor reliability and could benefit the most from additional automation, but which may not be among the worst performing circuits.

These expenditures will enhance reliability by reducing the number of customers affected by outages and outage durations, thereby reducing CMI and the number of momentary interruptions SCE's customers experience.[178] These deployments will provide a secondary benefit of preparing circuits for high-DER penetration by providing telemetry and performance information for circuit DERs and loads.[179] SCE will select the specific locations[180] for these deployments based on its expectation of where modern automation would provide the greatest CMI reduction.[181] SCE expects that CMI reductions from location-specific investments would have a net positive impact on SCE's SAIDI[182] metric. However, since circuits without automation may contribute more to SCE's overall SAIDI in a given year, these investments do not guarantee overall SAIDI performance improvements. Figure II-24 summarizes how reliability metrics relate to customer experience.

[177] Please refer to WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A - pp. 169 – 175 – Reliability-driven Distribution Automation Forecast.

[178] SCE's Customer Minutes of Interruption (CMI) is the total minutes every SCE customer was without power due to sustained outage.

[179] Note that both Reliability Driven Distribution Automation and DER Driven Distribution Automation use Modern Distribution Circuit Automation.

[180] Resolution E-4982, Attachment B, p. 41, specifies "local investments include field equipment installed on the distribution system to meet an identified or forecasted location-specific grid need including, but not limited to, safety and reliability needs or the integration of DERs (e.g. communication equipment for DERs that can be dispatched such as energy storage)."

[181] Please refer to WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A - pp. 169 – 175 – Reliability-driven Distribution Automation Forecast.

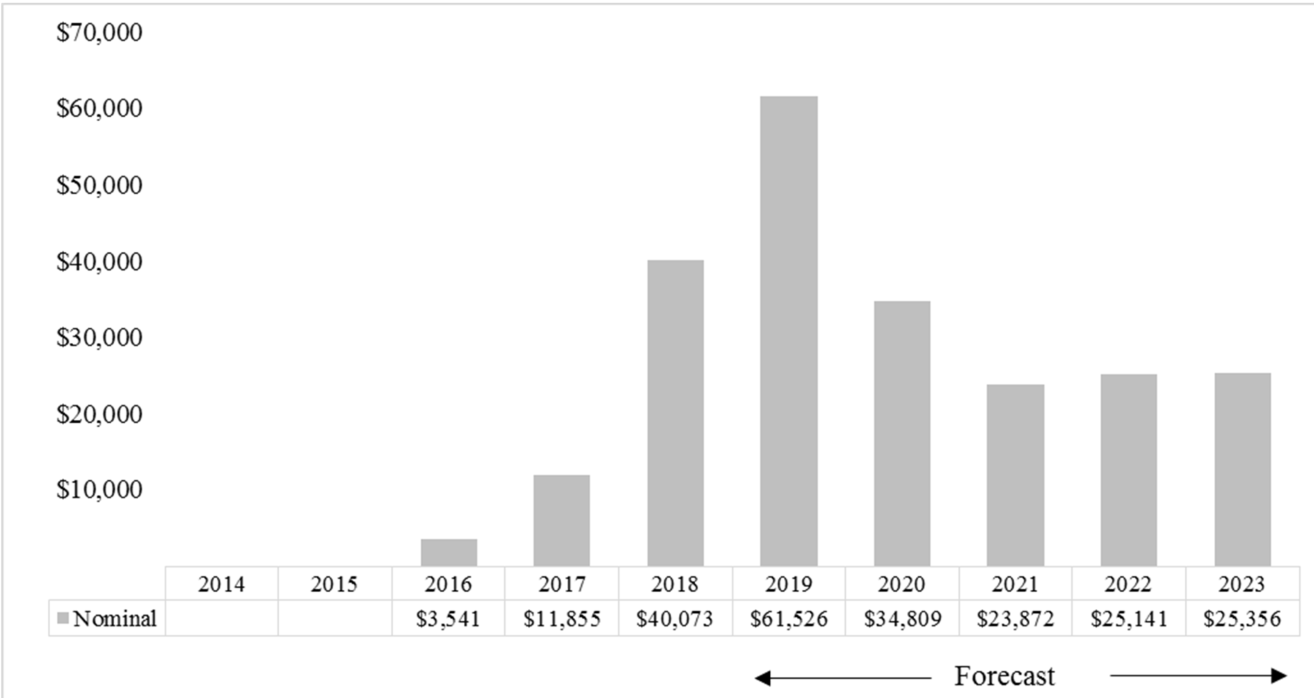
[182] SCE's System Average Interruption Duration Index is defined in accordance with IEEE 1366 as the total minutes every SCE customer was without power due to sustained outages (CMI) divided by the total number of customers.

Figure II-24
Understanding Reliability Metrics

Metric	Measurement	Customer Perspective
SAIDI (System Average Interruption Duration Index)	The number of minutes the average SCE customer experiences an outage lasting more than five minutes annually.	"What's the total time my power service will be unexpectedly interrupted this year?"
MAIFI (Momentary Average Interruption Duration Index)	The number of times the average SCE customer experiences an outage lasting five minutes or less annually.	"How many times will my power service be briefly interrupted for this year?"

Figure II-25 summarizes the 2014–2018 recorded and 2019–2023 forecast capital expenditures for Reliability-driven Distribution Automation.

Figure II-25
2014 – 2018 Recorded/2019-2023 Forecast Capital Expenditures for Reliability-driven Distribution Automation[183]
CWBS Element CET-PD-GM-RA
(Total Company - Nominal $000)



(2) <u>Basis for Capital Expenditure Forecast</u>

SCE will continue deploying the following distribution automation components through the 2021 GRC period: intelligent automated switches, RCSs with integrated grid sensors, RFIs, and circuit tie additions or enhancements. SCE's Reliability-driven Distribution Automation capital forecast is based on unit costs developed from its experience implementing this type of work over the past several years.[184]

[183] Please refer to WP SCE-02, Vol. 2, Pt. 1, Ch. II – Book A - pp. 178 - 179 – Capital Details by WBS for Reliability-driven Distribution Automation.

[184] Please refer to WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A - pp. 169 – 175 – Reliability-driven Distribution Automation Forecast, Unit Costs.

The three midpoint intelligent automated switch design provides value through reliability benefits as described in the 2018 GRC.[185] This automation architecture, if implemented system-wide, would reduce circuit segments between automated switches to approximately 500 customers, consistent with SCE's industry benchmarking.[186] However, for the 2021 GRC period, SCE will reduce the scope of this activity from what was envisioned in the 2018 GRC by adding one additional midpoint intelligent automated switch with fault interrupting capability (or RCS) and one limited circuit tie upgrade along with a tie RCS (+1/+1). This reduction is largely due to the need for available resources to support SCE's wildfire risk mitigation efforts.[187]

SCE also continues to believe that the intelligent automated switches with fault interrupting capability[188] provide higher value than RCSs. The Commission concluded in its 2018 GRC Decision "that beyond a limited number of installations, there is insufficient value to installing more advanced Remote Intelligent Switches."[189] However, SCE's latest BCA indicates that the intelligent automated switches with fault interrupting capability on any circuit provides substantial value.[190]

In the 2018 GRC, the Commission authorized SCE to install automatic reclosers (ARs)[191] for its WCR projects, where cost-effective. Intelligent automated switches with fault interrupting capability, which SCE proposes to include in its modern distribution automation approach,

---

[185] Please refer to WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A - pp. 180 – 185 – 2018 GRC Estimated Reliability Improvement due to Distribution Automation.

[186] SCE benchmarked other utilities automation programs and found the Duke Energy, Pennsylvania Power and Light, and Florida Power and Light intend to limit circuit segments to 500 customers between automated switches.

[187] SCE-04 V. 5, B. Wildfire Activities.

[188] Intelligent automated switches were referred to as remote intelligent switches or RISs in SCE's 2018 testimony. Intelligent automated switches with fault interruption are part of Fault Location, Isolation and Service Restoration (FLISR) in the DRP classification tables. *See* Supplemental Compliance Filing to Resolution E-4982, Southern California Edison Company's Updates to its Grid Modernization Classification Tables Appendix A pg. 25.

[189] D.19-05-020, Section 4.8.1.

[190] SCE uses the term "value" to refer to the present value of the incremental benefit minus the incremental cost of an investment. Please refer to WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A - pp. 169 – 175 – Reliability-driven Distribution Automation Forecasts. Benefit Cost Analysis Results.

[191] D.19-05-020, Section 4.8.1.

are simply modern versions of the ARs.[192] SCE proposes that the same reasonableness test used previously for WCR-driven automation should also apply to Reliability-driven Distribution Automation—specifically to its decision to use intelligent automated switches with fault interruption capability. SCE should have the flexibility to install any intelligent automated switch design that provides safety and reliability benefits, where there is an engineering rationale, and it is cost-effective.

f) **DER-driven Distribution Automation**

As described throughout the Grid Modernization chapter, customer adoption of DERs will increase the complexity of managing the electric grid. Left unabated, this operating complexity will increase the reliability challenges associated with higher amounts of DERs and result in decreased reliability.[193] DER-driven Distribution Automation is designed to mitigate this potential reliability degradation and to help accommodate forecasted DER growth.[194] This can be accomplished by deploying the appropriate type of automation to resolve specific engineering issues on a given circuit. In the 2021 GRC, SCE proposes adding RFIs to each DER-driven Distribution Automation circuit to improve system operator situational awareness.

When a circuit's forecast DER growth is expected to overload circuit components by exceeding their capacity, or when the overall magnitude of DERs at a substation impairs SCE's operational flexibility,[195] SCE must perform targeted infrastructure upgrades to improve the circuit's capacity to receive additional DERs. This is described in DER-driven DSP Circuits in SCE-02 Volume 4, Part 2: DER Driven Grid Reinforcement.

(1) **Program Description**

While in Reliability-driven Distribution Automation SCE proposes installing a suite of advanced automation tools to address a circuit with historically poor reliability, DER-driven Distribution Automation installations address the needs of circuits with high DER

---

[192] The vendor in this specific case is discontinuing the older AR controls. So, both SCE's intelligent automated switches with fault interruption capability and ARs will likely use the same hardware and, therefore, have the same cost in 2021 Test Year.

[193] DER integration challenges are discussed in the GMP in Appendix A, Section I.D.

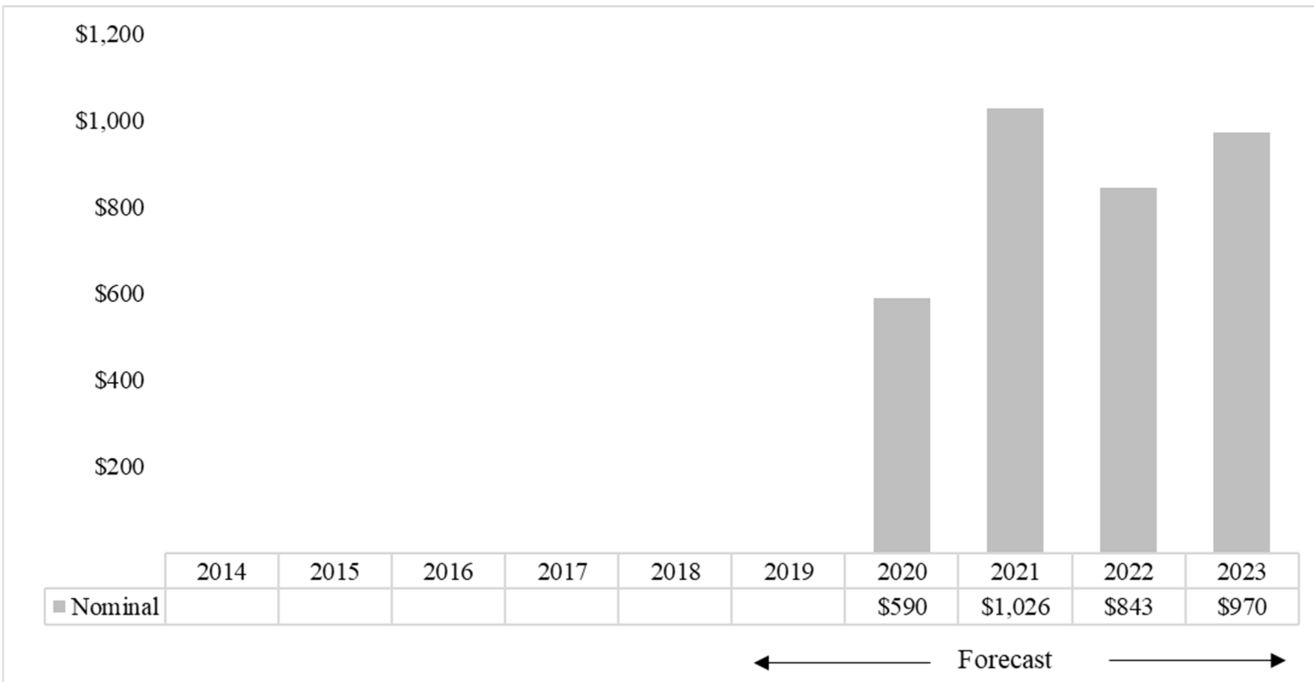
[194] Please refer to WP SCE-02, Vol. 4, Pt. 2, Ch. II – Book A - pp. 14 – 29 – High Distributed Energy Resources Planning Assumptions.

[195] Please refer to WP SCE-02, Vol. 4, Pt. 2, Ch. II – Book A - pp. 14 – 29 – High Distributed Energy Resources Planning Assumptions.

penetration. DER-driven Distribution Automation may include expenditures on circuit tie additions or enhancements, RFIs, RCSs with integrated grid sensors, and intelligent automated switches.

Figure II-26 summarizes the 2014–2018 recorded and 2019–2023 forecast capital expenditures for DER-Driven Distribution Automation.

Figure II-26
2014 – 2018 Recorded/2019-2023 Forecast Capital Expenditures for DER-driven Distribution Automation[196]
CWBS Element CET-PD-GM-DM
(Total Company - Nominal $000)



	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Nominal							$590	$1,026	$843	$970

(2) <u>Basis for Capital Expenditure Forecast</u>

SCE identified approximately 70 distribution circuits with high DER penetration nearing their planned loading limits[197] over the next five years due to DER generation. Given the need for real-time operating data on circuits congested with DERs, SCE only plans to deploy RFIs on these 70 circuits in the 2021 GRC period. In future GRC periods, as SCE further monitors and

[196] Please refer to WP SCE-02, Vol. 2, Pt. 1, Ch. II – Book A - pp. 186 – 187 – Capital Details by WBS for DER-driven Distribution Automation.

[197] Please refer to WP SCE-02, Vol. 4, Pt. 2, Ch. II – Book A - pp. 14 – 29 – High Distributed Energy Resources Planning Assumptions.

assesses the reliability impacts of high DER penetration on these circuit segments and circuit ties, SCE will use this information to inform further DER-driven Distribution Automation deployments. SCE expects these future deployments will include intelligent automated switches with the goal of improving reliability on these circuits.

SCE's cost estimates are based on established RFI unit costs. Since SCE has been deploying RFIs over the last several years, the unit costs are well established and represent a reasonable estimate of SCE's cost to deploy the technology.[198]

g) Small-scale Deployments

(1) Program Description

Small-scale Deployments include pilots of limited quantities of distribution automation components across SCE's various geographic regions prior to large-scale deployment. Small-scale deployments allow SCE to validate the functionalities of the components in different operating environments and to test the tools and processes needed to implement and operate them effectively. This also helps SCE to understand the training and skillsets required to plan, install, and operate these technologies at a much a larger scale.

SCE is currently evaluating a few different types of RFIs for different installation types (e.g., underground and pad-mount) and geographic areas with lower power demand-such as the rural areas. SCE is also planning to deploy a mobile phone application that RFI installers can use to register the devices with SCE's DMS automatically, to ensure that the intended RFI capabilities and associated benefits can be realized immediately upon installation. When SCE deploys technology such as a mobile phone application, it must also develop change advocates for the technology throughout the company. More broadly, technology deployments require SCE employees to acquire skills and knowledge about the infrastructure deployments. As part of expanding its network of technology change agents through T&D Deployment Readiness, the groups that drive this change need access to capital equipment and tools to support the knowledge transfer. The capital equipment and tools that prepare SCE for the most effective use of new technology is included in Small-scale Deployments.

Small-scale Deployments supports SCE's broader technology lifecycle management approach. To ensure that SCE deploys technologies that support SCE's corporate objectives and the Commission's policy objectives, SCE manages technology launches through a

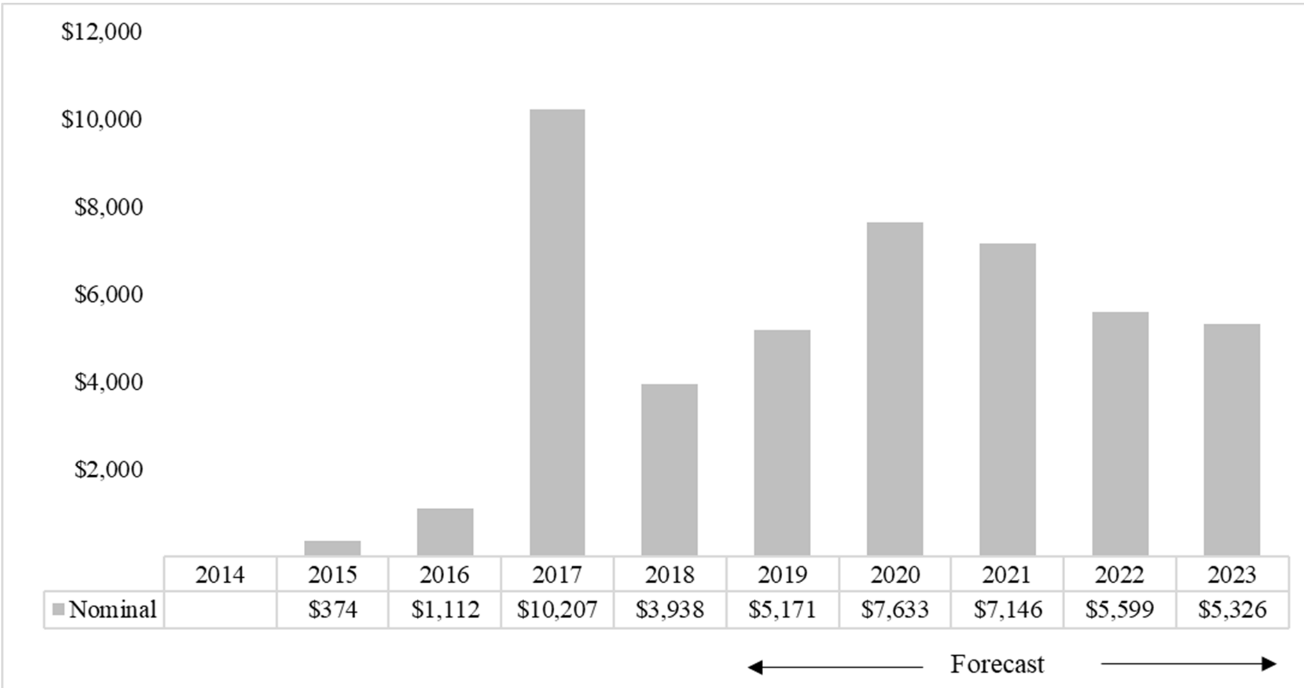
[198] Please refer to WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A - pp. 188 – 190 – DER-driven Distribution Automation Forecasts.

technology lifecycle process that includes five high-level stages. Stage 1 identifies the initial technology and assesses its alignment with SCE's business needs. Stage 2 involves detailed technology launch planning and any necessary initial studies to validate the technology concept. Stage 3 consists of the technology evaluation, including lab and field demonstrations and any necessary pilot activities (including small-scale deployments). Stage 4 includes activities to help ensure the technology transitions from evaluation to deployment as seamlessly as possible. This includes completing OCM activities such as stakeholder communications and engagement, training and deployment preparations. Stage 5 represents wide-scale deployment.

The T&D Deployment Readiness team supports Stage 3, beginning with the lab demonstration. However, due to limited funding, technologies are typically only demonstrated and piloted in a single distribution region. Since a crucial part of field personnel training includes hands-on use and familiarity with the technology, SCE has included Small-scale Deployments in Stage 3 of its technology lifecycle management process. This helps ensure that the technologies operate as intended—enabling the desired capabilities and realizing the associated benefits—when deployed through one of SCE's capital programs.

Figure II-27 summarizes the 2014–2018 recorded and 2019–2023 forecast capital expenditures for Small-scale Deployments.

Figure II-27
2019-2023 Forecasted Capital Expenditures for
Small-scale Deployments[199]
CWBS Element CET-PD-GM-IS
(Total Company - Nominal $000)



(2) <u>Basis for Capital Expenditure Forecast</u>

SCE demonstrates pre-commercial technologies through the Electric Program Investment Charge (EPIC) balancing account. Many distribution automation technologies would benefit from small-scale deployments, provided that the technologies advance successfully through SCE's technology lifecycle management process. These technologies include various types of intelligent automated switches and grid sensors. Since the sensors and switches expected to complete small-scale deployments are similar to the existing classes of devices used today, SCE used the unit costs of existing devices for the capital forecast.[200]

[199] Please refer to WP SCE-02, Vol. 2, Pt. 1, Ch. II – Book A - pp. 191 – 192 – Capital Details by WBS for Small-scale Deployments.

[200] Please refer to WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A - pp. 193 – 195 – Small-scale Deployments Capital Workpaper.

h) Reliability-Driven Substation Automation

Substation automation systems such as SA-1—and, to a lesser extent, distribution automation devices—have enabled service restoration following faults. Upgrading the substation systems to SA-3 will provide additional reliability and safety features while creating a flexible and adaptable substation that can more easily integrate DERs. This workstream's primary near-term benefit is improved reliability. This differs from SCE's other substation equipment replacement programs in that it proactively replaces all relay equipment in the substation to prepare for DERs. It also bundles the CSP deployment scope to provide cybersecurity for communications to and from the substation.

(1) Program Description

SCE's SA-3 design complies with the IEC 61850 standard, which enables interoperability between vendor devices.[201] SCE constructed its previous substation automation systems' remote terminal unit/[202] programmable logic controller[203] (RTU/PLC) and SA-1 components using a propriety design. The manufacturers of SA-1 and many older RTU/PLC substation components no longer support many of those hardware components and as a result, replacement parts are difficult to procure. RTU/PLCs are sometimes upgraded to replace outdated and obsolete systems, but the integration of DERs and cyber-secure communications require a new platform. SA-3 provides this new platform. SA-3 can be integrated with various vendor solutions for intelligent electronic devices already deployed at a substation. SA-3 can also integrate with the CSP, which runs cybersecurity applications to protect the SA-3 components.

Figure II-28 summarizes the 2014–2018 recorded and 2019–2023 forecast capital expenditures for Reliability-driven Substation Automation.

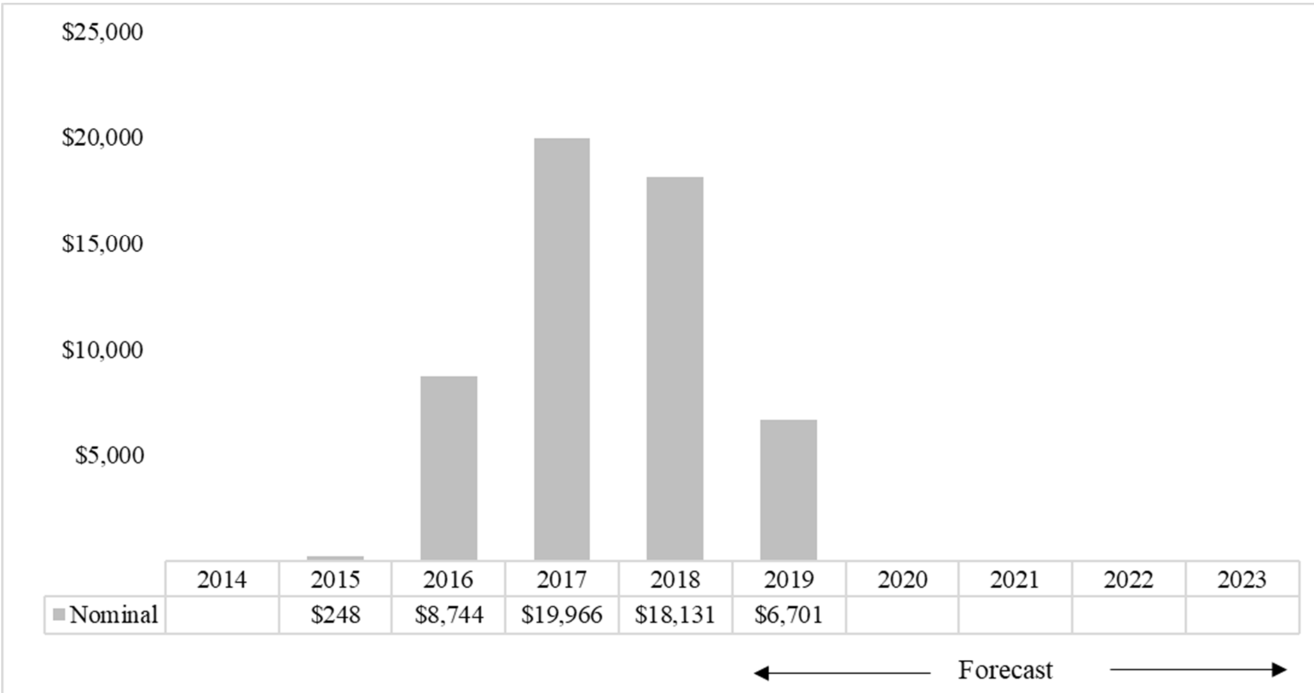
---

[201] Interoperability is an important affordability feature of digital systems of devices that ensures that as technologies evolve, industry standards are updated, and/or vendors discontinue support for various pieces of hardware that it is not necessary to do full overhauls of the complete substation automation system but rather afford SCE opportunity to replace discrete components as they become obsolete or fail. Using interoperable components also encourages vendor competition with the hope that this competition makes equipment pricing more reasonable in the future and delivers savings to customers over time.

[202] A Remote Terminal Unit (also sometimes called a Remote Telemetry Unit) Serves as a Supervisory Control and Data Acquisition (SCADA) interface, and is integrated with communications from devices and can relay that information back to a central site.

[203] A Programmable Logic Controller is a digital computer that may be programmed to perform a number of different functions and is suitable for direct control of local devices when communication is limited to a central site or considered unnecessary.

Figure II-28
***2014 – 2018 Recorded/2019-2023 Forecast Capital Expenditures for Reliability-driven Substation Automation*[204]**
CWBS Element CET-ET-GM-SA-781702
(Total Company - Nominal $000)



(2) <u>Basis for Capital Expenditure Forecast</u>

SCE has upgraded 13 substations to SA-3. These substations had already been completed—or were near completion—when the 2018 GRC Decision was released. The total forecast for 2019 is based on the recorded costs associated with five of the six substations near completion at the end of June. SCE will complete the last substation in 2019.[205]

SCE will not initiate work under Reliability-driven Substation Automation beyond 2019. SCE's approach to addressing stations experiencing high relay failure rates in the 2021 GRC period will continue under the SCE's substation construction and maintenance programs discussed

[204] Please refer to WP SCE-02, Vol. 2, Pt. 1, Ch. II – Book A - pp. 196 – 197 – Capital Details by WBS for Reliability-driven Substation Automation.

[205] Please refer to WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A - pp. 198 – 199 – Reliability-driven Substation Automation Forecast.

in SCE-02, Volume 3. Substations that require SA-3 due to DER integration challenges are described in DER-driven Substation Automation below.

i) DER-driven Substation Automation

Substation automation systems such as SA-1—and, to a lesser extent, legacy distribution automation devices—have enabled system recovery from problems such as faults on SCE's distribution system. Upgrading these systems to SA-3 will support additional safety,[206] reliability,[207] and customer empowerment[208] features while creating a flexible and adaptable station that can more easily integrate DERs.

(1) Program Description

SCE's SA-3 design complies with the IEC 61850 standard, which enables interoperability[209] between vendor devices. SCE constructed its previous substation automation systems (SA-1 using RTU/PLC) using a propriety design that provides no interoperability between components made by different vendors. As mentioned earlier, manufacturers no longer support many of the SA-1 hardware components, so replacement parts are difficult to procure. Though RTU/PLCs are sometimes upgraded to replace outdated and obsolete systems, SA-3 provides a new platform that can be integrated with various vendors' solutions for intelligent electronic devices already deployed at a substation. SA-3 can also integrate with the CSP, which runs cybersecurity applications to protect the SA-3 components.

Figure II-29 summarizes the 2014–2018 recorded and 2019–2023 forecast capital expenditures for DER-Driven Substation Automation.

---

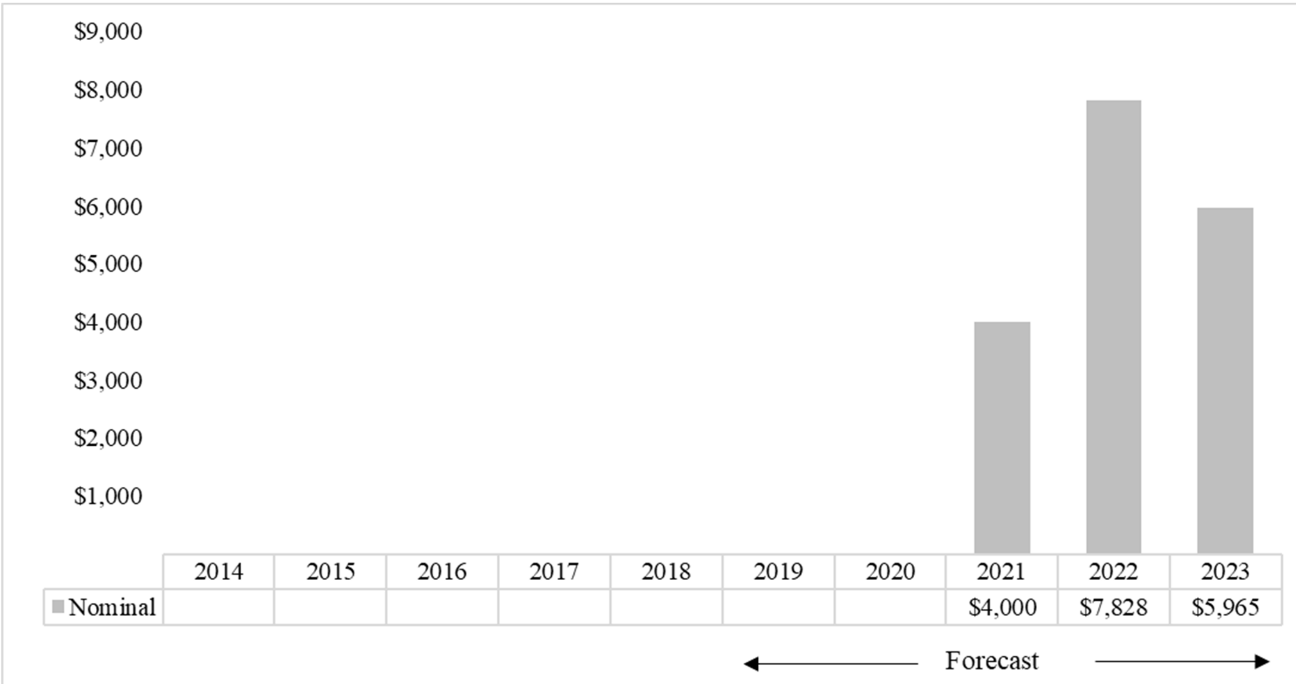
[206] Safety benefit is incremental over older SA-1 relays that historically have failed at high rates in service.

[207] Reliability benefits are gained by accurately monitoring DERs and informing the GMS with quality data such that GMS can perform system operator assisted switching.

[208] Customer empowerment is related to reducing the time and cost to interconnection customer associated with upgrading relays to bi-directional telemetry or updating settings to accommodate DER interconnections.

[209] Using interoperable components encourages vendor competition and this competition makes equipment pricing more reasonable in the future since it can be competitively evaluated.

Figure II-29
2014 – 2018 Recorded/2019-2023 Forecast Capital Expenditures for DER-driven Substation Automation[210]
CWBS Element CET-ET-GM-AD-781700
(Total Company - Nominal $000)



(2) <u>Basis for Capital Expenditure Forecast</u>

The substations selected for DER-driven Substation Automation are those identified by SCE as having high DER penetration.[211] High DER penetration includes several factors, which together point to severe operational impacts at a given substation due to DER driven congestion on the lines, circuit breakers, and other apparatus connected to the substation. Upgrading these substations will address the adverse operational limitations and asset management issues. The forecasted expenditures were developed using costs developed from recently completed full SA-3 conversion

[210] Please refer to WP SCE-02, Vol. 2, Pt. 1, Ch. II – Book A - pp. 200 – 201 – Capital Details by WBS for DER-driven Substation Automation.

[211] Please refer to WP SCE-02, Vol. 4, Pt. 2, Ch. II – Book A - pp. 14 – 29 – High Distributed Energy Resources Planning Assumptions.

projects under Grid Modernization Reliability-driven SA-3 and are detailed in the supporting workpapers.[212]

5. Capital Expenditures for DER Hosting Capacity Reinforcement

Capital expenditures DER Hosting Capacity Reinforcement include the subset of projects that SCE has identified for reliability and technology pilot purposes. SCE's load growth planning process and its related DER studies have identified Grid Reinforcement projects driven by immediate capacity and other planning criteria needs. These projects are therefore included in the Load Growth section of this volume.[213]

a) Subtransmission Relay Upgrade Program

(1) High-level Program Description

SCE has routinely replaced aging electromechanical subtransmission line protective relays within the IR program, as discussed in SCE-02, Volume 03 - Substation Protection and Control Relay Replacements. While the work in Grid Modernization's Subtransmission Relay Upgrade Program is similar, it is driven by DER penetration, which is not considered in the Substation Protection and Control Relay Replacement program. In 2016, SCE determined that some of the electromechanical relays installed prior to the 1990s may limit subtransmission system reliability in a high-DER environment. SCE requested funds to replace these relays in its 2018 GRC request. SCE has since decelerated the DER-driven Subtransmission Relay Upgrade Program to a pilot project.

The Subtransmission Relay Upgrade Program replaces 66kV and 115 kV line protection relay devices in the Viejo system as part of the pilot. Although SCE scaled down this program, SCE still recognizes the value of telemetry to measure power flow direction on its subtransmission system. This telemetry may be useful in optimizing the configuration of the subtransmission and distribution networks to deliver energy savings to customers.[214] SCE expects to use the learnings from this pilot to inform future GRC requests.

Table II-19 summarizes the high-level capability that SCE expects the Subtransmission Relay Upgrade Program to support.

---

[212] Please refer to WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A - pp. 169 – 175 – Reliability-driven Substation Automation Workpaper and WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A - pp. 202 - 206 – DER-driven Substation Automation Workpaper.

[213] Please refer to SCE-02 Volume 4, Pt. 2, Ch. II - DER Driven Grid Reinforcement.

[214] Optimizing the grid configuration could result in lower voltage across the system and improve the power factor, which would reduce customer energy consumption without requiring a change in customer behavior.

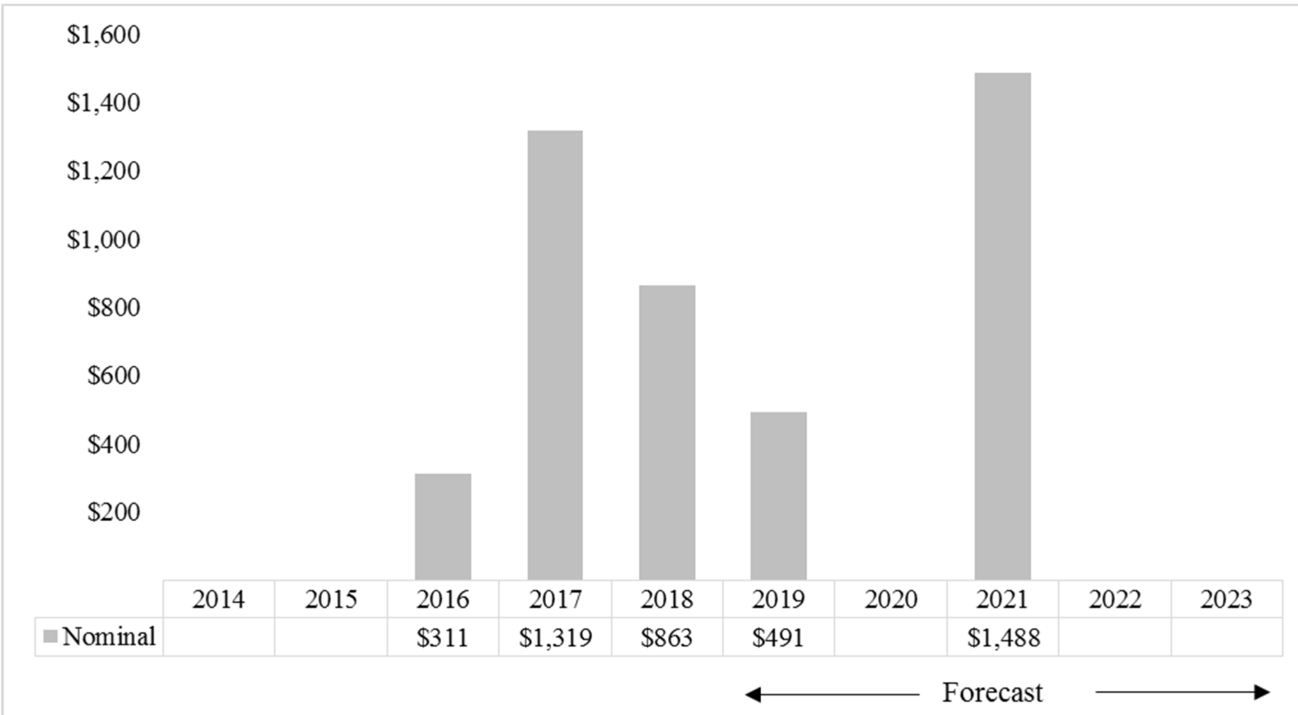
Table II-19
Subtransmission Relay Upgrade Program-supported Capability

Capability Categories	High-level Capabilities
DER Integration Capacity Provides sufficient DER integration capacity to avoid circuit or equipment overloads due to DERs	a. Expanded DER integration capacity

(2) Summary of Cost Forecast

Figure II-30 summarizes the 2014–2018 recorded and 2019–2023 forecast capital expenditures for the Subtransmission Relay Upgrade Program.

Figure II-30
2014 – 2018 Recorded/2019-2023 Forecast Capital Expenditures for Subtransmission Relay Upgrade Program[215]
CWBS Element CET-ET-GM-SA-781700
(Total Company - Nominal $000)

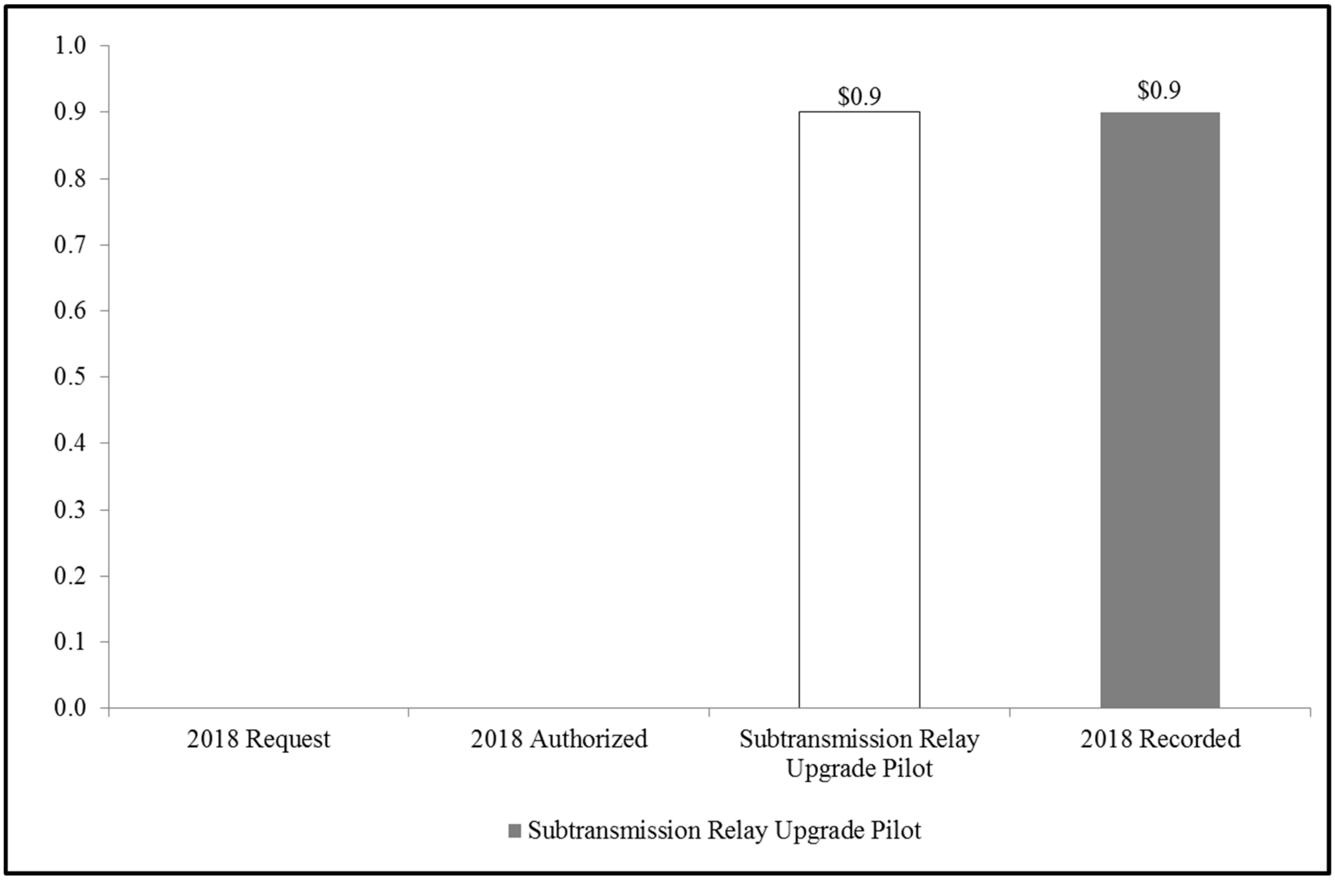


(3) <u>Comparison of Authorized 2018 to Recorded</u>

The 2018 GRC Decision requires SCE to compare the 2018 authorized amounts to the recorded amounts; Figure II-31 compares these amounts for Subtransmission Relay Upgrade Program capital expenditures.

215 Please refer to WP SCE-02, Vol. 2, Pt. 1, Ch. II – Book A - pp. 207 – 208 – Capital Details by WBS for Subtransmission Relay Upgrade Program.

Figure II-31
Subtransmission Relay Upgrade Program
2018 GRC Authorized Variance Summary 2018 Capital
(Total Company - Constant 2018 $Millions)



SCE received no authorized funding for this program in the 2018 GRC Decision. However, expenditures began on the pilot prior to the 2018 GRC filing and, due to multiple project dependencies associated with the upgrade including the completion of a CSP at the Viejo Substation, are expected to continue until 2021. SCE's rationale for the pilot has evolved since 2018, and we respectfully request that the Commission consider the potential customer benefits of this pilot in the 2021 GRC. The ability to measure power flow direction at the subtransmission relays provides an opportunity for SCE's GMS to co-optimize the subtransmission and distribution systems using Conservation Voltage Reduction principles like SCE's current DVVC.[216] This pilot could allow SCE to

[216] Please refer to SCE-02 Vol. 4 Pt.2 - Distribution Volt VAR Control (DVVC).

reduce customer energy costs by reducing energy losses in its system without requiring a change in customer behavior. The installed equipment will be used and useful in providing advanced system protection capabilities to SCE's Viejo subtransmission system.

(4) Need for Capital Program

Market and technology factors drive SCE's need for the capabilities supported by the Subtransmission Relay Upgrade Program. The specific investment drivers and customer benefits SCE expects to result from these capabilities are summarized below.

(a) Drivers

(i) Market Drivers

A wider array of DER choices and financing options, and declining costs continue to drive increasing customer adoption of solar PV, electric vehicles and other DERs. This higher pace of customer adoption, which is driven by market forces as well as California and federal policies, is driving SCE's need to augment its capabilities in areas forecasted to have high-DER penetration. Upgrading subtransmission relays in areas with high DER adoption could arrest potential safety and reliability issues in these areas.

(ii) Technology Drivers

Most legacy protective relaying devices are electromechanical and have no provision for modern relaying methods. They are typically set to monitor one system condition (e.g., current, voltage, or frequency). In addition, many of these legacy relays do not include telemetry. The majority of subtransmission substations channel networked power flow from major bulk transmission substations to networked and radial subtransmission substations. When the direction of the current changes frequently due to intermittent DER generation, more sensitive and secure telemetry from protective relays is required to maintain system stability. SCE did not account for DER generation when developing its subtransmission substations. The subtransmission substations are therefore not equipped with the protective relaying equipment required to detect two-way power flows. As the number of DERs continues to increase on the distribution system, two-way power flows and intermittency impacts will also increase. The legacy protective relays at the substation cannot react accurately to system conditions in the presence of DER-driven voltage fluctuation and reverse power. This introduces challenges to system safety, reliability, power system planning, and real-time load flow estimation.

(b) Benefits

(i) Safety

Upgrading legacy protective relays at substations with modern relays would allow SCE to react accurately to system conditions in the presence of DER driven reverse power. This would resolve potential safety challenges associated with the legacy subtransmission relays.

(ii) Reliability

Upgrading legacy protective relays at substations with modern relays would also resolve potential reliability challenges associated with the legacy subtransmission relays, potentially helping to avoid circuit outages that result from misoperation of the subtransmission relays.

(iii) Decarbonization

Upgrading legacy protective relays at substations forecasted to experience high DER penetration will increase the ability of the substation to integrate higher amounts of DERs. Interconnecting additional DERs would reduce the need for incremental GHG-emitting generation resources.

(iv) Customer Empowerment

Upgrading legacy protective relays at substations forecasted to experience high DER penetration will increase the ability of the substation to integrate higher amounts of DERs. This would empower customers with a greater number of clean energy choices.

(v) Economic Efficiency

The pilot will familiarize SCE with modern subtransmission system operation and control to learn how to optimize operations across the subtransmission and radial distribution systems to reduce overall system voltage levels, thereby reducing the total energy delivered without requiring any change in customer behavior—also referred to as Conservation Voltage Reduction.

(5) Basis for Capital Expenditure Forecast

In its 2018 GRC rebuttal, SCE agreed with TURN that there was no need for a large Subtransmission Relay Replacement Program in the 2018 GRC cycle since SCE's engineering analysis concluded that SCE's systems are capable of managing load encroachment conditions on the subtransmission network. However, one project, the Viejo Subtransmission Relay upgrade project had already progressed to the execution stage and SCE continued it as a technology pilot. Construction will be completed in the [217]2021 GRC period. SCE seeks recovery of the pilot costs based on the following: (1) the equipment is expected to be used and useful in the 2021 GRC period and enhances equipment safety and reliability on the subtransmission network, (2) SCE will need to train personnel and update procedures to include the modern subtransmission relaying equipment in the future, and (3) the pilot will familiarize SCE with modern subtransmission system operation and control, which will provide valuable lessons about how to optimize operations across the subtransmission and radial distribution systems to reduce overall system voltage levels to achieve Conservation Voltage Reduction benefits.

[217] Please refer to WP SCE-02, Vol. 2, Pt. 1, Ch. II – Book A - pp. 209 – 210 – Subtransmission Relay Upgrade Program Capital Workpaper.

III.

GRID TECHNOLOGY ASSESSMENTS, PILOTS & ADOPTION

A. Overview

Since the Grid Technology organization (previously "Advanced Technology") was formed in 2009, SCE has taken measured and prudent steps to identify and assess promising technologies. We test the technology's performance under controlled conditions where service reliability and safety are not affected. We then pilot the technology in a real, integrated grid environment prior to deploying or connecting the technology across our power grid. As public policy goals and technological capabilities continue to evolve, our technology-related efforts continue to increase in importance. Our work here helps SCE use technology to deliver safety, reliability, wildfire resiliency, decarbonization, customer empowerment and affordability benefits.

The State's policies[218] are dramatically changing the way electricity is produced and consumed. These policies include reducing greenhouse gas emissions, increasing the use of renewable energy, offering customers greater choices and control over their energy use, reducing the utility's environmental footprint, and addressing climate change impacts (including wildfire). Meanwhile, customers are accelerating the adoption of technologies such as photovoltaic (PV) solar generation[219] and electric vehicles.[220] In addition, California is already experiencing the negative impacts of climate change with the increasing threat posed by wildfires to public safety and economy. Supporting these important public policies and meeting our customers' changing needs has affected how SCE must build and operate the grid. New and better technologies are a key part of our efforts.

SCE's Grid Technology organization provides technology solutions to serve our customers' changing needs and comply with many ambitious federal and state energy policy targets while maintaining grid safety and reliability. New technologies are identified, assessed for their maturity and performance, and tested for their intended purposes and integration implications. These new technology solutions must be prudently verified and validated before SCE makes large-scale investment and

---

[218] These policies include SB 1078 (2002), SB 107 (2006), SB X1-2 (2011), Executive Order S-3-05 (2005), AB 32 (2006), SB 350 (2015), SB 32 (2016), AB398 (2017) and the CARB Proposed Scoping Plan (2017).

[219] Behind-the-meter PV capacity in California was forecast to reach approximately 8,000 MW at the end of 2018, climbing from less than 3,000 MW in 2014 ("Behind-the-Meter PV Forecast" presented at the IEPR Workshop December 6, 2018).

[220] EV market share in California has climbed from 1.6% in 2014 to 4.1% in 2018 YTD ("2018 IEPR Update Light Duty PEV Forecast" presented at IEPR Workshop December 6, 2018).

deployment decisions, including whether and to what degree to deploy or to prepare its grid and operations to incorporate such technologies. After SCE applies its rigorous process, the right technologies can be safely and predictably integrated into SCE's grid. If we "bolt" newer technologies onto our grid without following the careful process outlined above, adverse grid performance and system conditions can result.

Under California's recently expanded Renewables Portfolio Standard (RPS), SCE must deliver 50 percent of bundled service customers' energy from renewable resources by 2030. Intermittent sun and wind conditions cause renewable power generation to fluctuate significantly. These power fluctuations, left unaddressed, can result in serious problems to electric distribution equipment, and can even adversely affect customers' electrical devices. The increasing number of distributed energy resources (DERs) on customer homes and businesses has increased the complexity of grid operations; these new configurations present challenges and opportunities for the distribution grid.

Grid Technology identifies and assesses promising technologies, tests their performance in a controlled environment where system conditions can be studied without affecting safety and reliability, and demonstrates and pilots chosen technologies on the grid. In this way, SCE prudently examines and tests out technologies before deploying them across the power grid.

Our work in Grid Technology also supports the electrification of transportation in California. By the end of Q1 2019, SCE reserved funding for a total of 1,321 charge port commitments under the Charge Ready Pilot,[221] and the Commission has authorized bridge funding to continue the pilot while the Commission considers SCE's Charge Ready 2 application supporting 50,000 charge ports.[222] SCE has launched its Charge Ready Transport program to provide infrastructure supporting 8,490 ports for truck and bus charging.[223] The California Air Resources Board (CARB) has set a statewide goal for public transit agencies to transition to 100 percent zero-emission bus fleets by 2040, an estimate of 12,000

[221] *See* Southern California Edison Company's Charge Ready Program Pilot Quarterly Report (filed on May 31, 2019), p. 5.

[222] *See* D.18-12-006 (granting SCE's bridge funding request) and Application 18-06-015 of Southern California Edison Company (U 338-E) for Approval of its Charge Ready 2 Infrastructure and Market Education Programs.

[223] *See* sce.com/chargereadytransport.

buses.[224] The proliferation of electric vehicles can overload distribution circuits, and if not managed properly, will lead to grid instability or outages.

The growth of transportation electrification has been profound, and growth efforts are only increasing. According to the Electric Power Research Institute (EPRI), 183,376 electric light-duty vehicles were registered in SCE's service territory by the end of May 2019. EV sales were around eight percent of new car sales in California in 2018 as compared to 2017, when EV sales made up five percent of new car sales.[225] Grid Technology, through its test facilities, collaborative projects and engineering staff, supports SCE's Charge Ready programs to qualify charging systems and evaluate other supporting elements that customers may want to incorporate, such as energy management systems and energy storage.

Despite California's progressive energy and environmental policies and objectives, California is beginning to experience negative impacts of climate change. Higher temperatures, prolonged droughts, dry fuels and dead/dying trees create conditions that increase the potential for catastrophic wildfire events occurring. After the devastating 2017 and 2018 wildfire seasons, the California Legislature responded to the dramatic change in the California landscape with Senate Bill 901, which among other things, requires all electrical corporations in the state to submit an annual regulatory filing outlining their respective Wildfire Mitigation Plans (WMP). SCE's 2019 WMP describes "strategies, programs and activities that are in place, being implemented, or are under consideration to address and mitigate the threat of electrical infrastructure-associated ignitions that could lead to wildfires, further harden the electric system against wildfires and enhance wildfire suppression and response efforts."[226]

In 2018, SCE also filed its Grid Safety & Resiliency Program Application (A.18-09-002), seeking approval and funding to deploy a variety of wildfire- and emergency-response related strategies and technologies. The market has responded with multiple potential solutions for more effectively identifying and mitigating wildfire risks. Grid Technology plays a pivotal role in screening potential technological solutions and accelerating the use of beneficial technologies that require some level of validation before they can be safely deployed.

---

224 Innovative Clean Transit regulation approved by the California Air Resources Board (CARB) on December 14, 2018.

225 As of May 2019, data from the Electric Power Research Institute (EPRI) on annual light-duty vehicle sales, based on third-party registration data.

226 *See* R.18-10-007, Southern California Edison Company's (U 338-E) 2019 Wildfire Mitigation Plan (February 6, 2019), at p. 7.

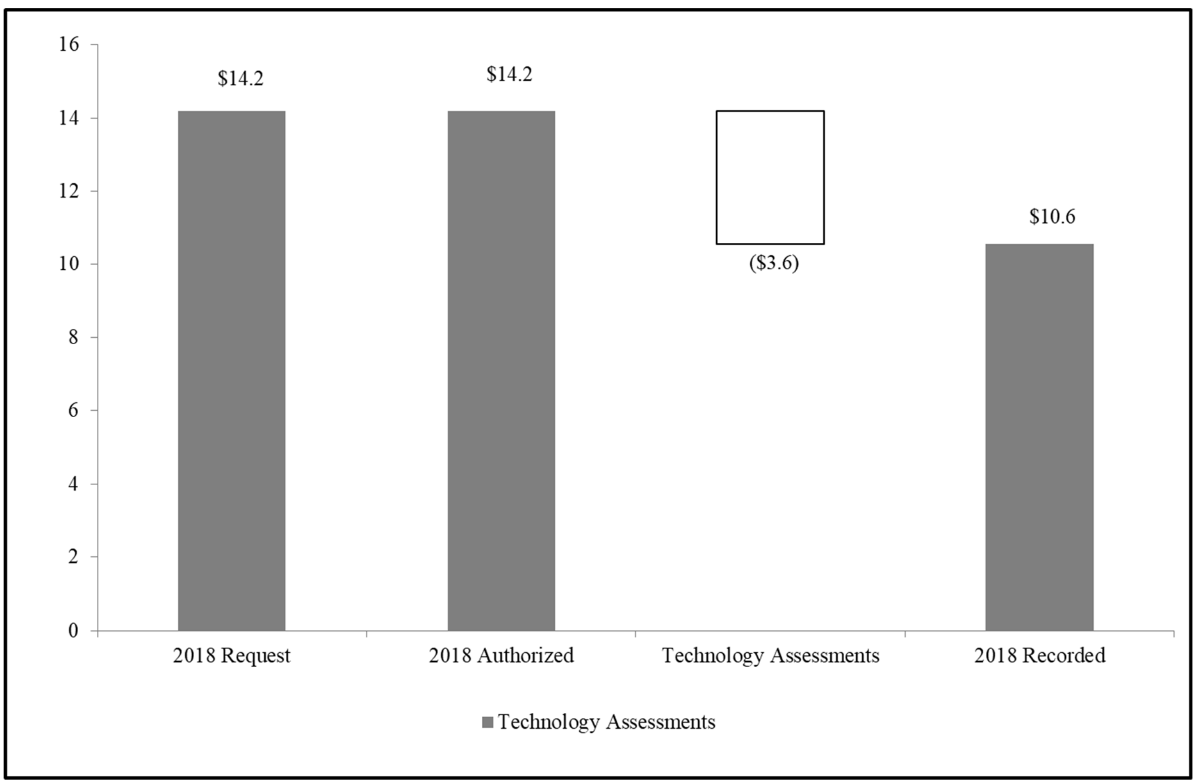
SCE forecasts $12.954 million in O&M expenses in Test Year 2021 and $17.0 in capital expenditures from 2019 – 2023 to manage Grid Technology Assessments, Pilots and Adoption.

B. 2018 Decision

1. Comparison of Authorized 2018 to Recorded

The 2018 GRC Decision requires that SCE compare the 2018 authorized amounts to the recorded amounts;[227] Figure III-32 and Figure III-33 below compare amounts for O&M expenses and capital expenditures.

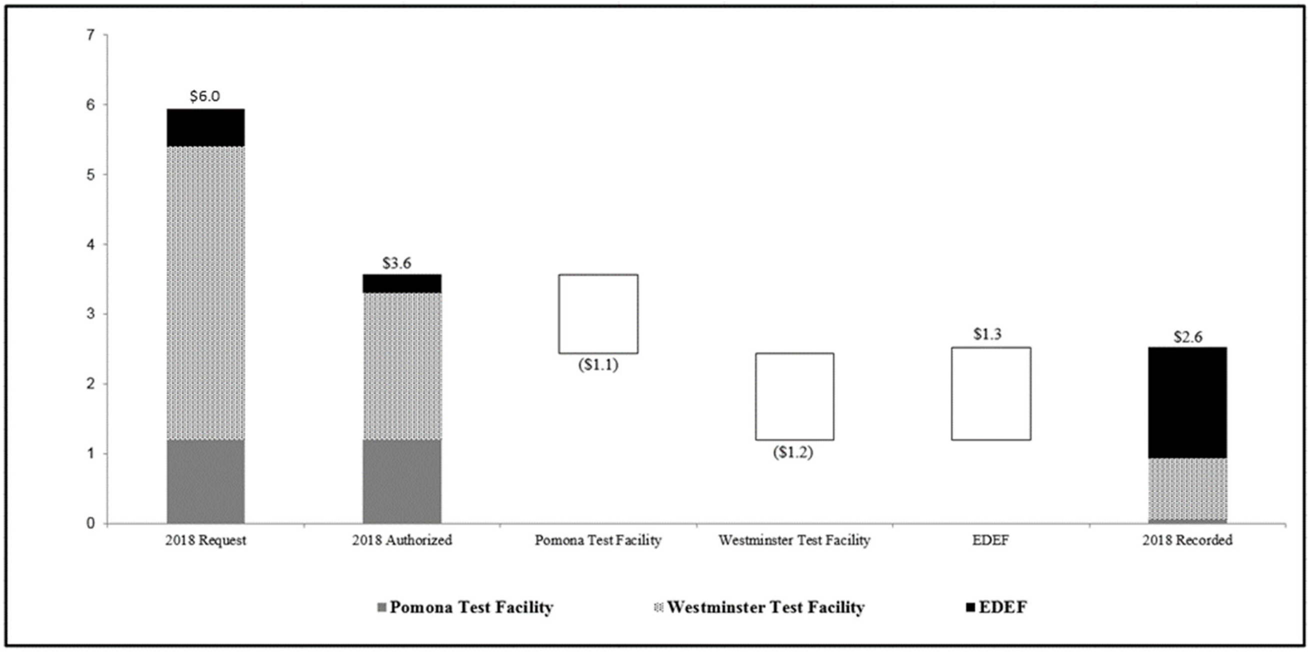
Figure III-32
Grid Technology Assessments, Pilots & Adoption
2018 GRC Authorized Variance Summary 2018 O&M[228]
(Constant 2018 $Millions)



[227] D.19-05-020, Ordering Paragraph 22, pp. 441-442.

[228] Please refer to WP SCE-07, Vol. 1 – O&M Authorized to Recorded.

Figure III-33
Grid Technology Assessments, Pilots & Adoption
2018 GRC Authorized Variance Summary 2018 Capital[229]
(Total Company - Nominal 2018 $Millions)



The Commission's authorized forecast for its Pomona Labs facility was $1.205 million. SCE's recorded 2018 expense was $0.065 million, which was $1.140 million less than authorized. This difference in spending is due to the shifting direction of testing and evaluating activities at the Pomona Labs. The focus for testing and evaluating Transportation Electrification (TE) products is now less on evaluating the performance of electric vehicles themselves, but rather on the grid-tied devices that provide power to electric vehicles and the associated impact of those devices on vehicles and on the distribution grid. This reduced the spending on mobile data acquisition devices, such as emissions testing equipment, fuel flow meters, and other automotive-type equipment.

Additionally, our stationary energy storage (ES) evaluation and testing is now no longer focused on variable direct current (DC) evaluation, but rather on alternating current (AC) integration of the systems. This change in focus in ES has also led to reduced spending on data acquisition devices and test apparatus, such as environmental chambers and DC power cyclers. The focus moving forward for

[229] Please refer to WP SCE-07, Vol. 1 – Capital Authorized to Recorded.

TE and ES testing and evaluating will be on high-power applications that will leverage a high voltage interconnection at a minimum of 12 kV. Later in this testimony, we provide further details.

The Commission's authorized forecast for the Westminster Labs Test Facility was $2.098 million. SCE's recorded 2018 expense was $0.861 million, which was $1.237 million less than authorized. This difference in spending was driven by our decision to defer spending on certain prudent projects and improvements we had proposed in our Test Year 2018 GRC. We deferred these items in 2018 due to the absence of Commission guidance throughout 2018 on what we were authorized to spend in that year.

The Commission's authorized forecast for the Equipment Demonstration and Evaluation Facility (EDEF) was $0.264 million. SCE's recorded 2018 expense was $1.634 million, which was $1.370 million greater than authorized. This difference in spending is due to additional work necessary to address safety and environmental concerns raised by the City of Westminster and Orange County Fire Authority (OCFA), as well as seismic safety concerns identified in the EDEF control building. The City of Westminster required a more robust physical security wall, egress to enter a nearby flood control channel, and property storm drains to address approved storm water runoff. The OCFA required a redesign of the site's fire suppression system and first responder ingress plan. Finally, the project engineer identified safety issues with the EDEF control building seismic footing requirements for large equipment being installed in the indoor test facility. If not properly addressed, this large equipment could potentially fall on engineers during an earthquake.

Despite all of these issues, SCE could not completely stop work on EDEF as the site was needed to support the evaluation of wildfire mitigation technologies (some examples are covered conductor, high impedance detection, and Intelligent Modern Pole).[230]

C. O&M Forecast

Table III-20 below summarizes the 2014–2018 recorded and 2019–2021 forecast O&M expenditures for the Grid Technology Assessments, Pilots and Adoption BPE.

---

[230] The concept of an Intelligent Modern Pole was created by SCE Grid Technology and Modernization. This device is a fiberglass/steel hybrid pole outfitted with several sensors that can measure temperature, strain, impact, and GPS in order to give real time telemetry of the state of the pole. This pole can lead to real-time detection of pole overloading, wire down, and wildfire. Once fully developed, this product can aid in SCE's grid resiliency efforts.

Table III-20
Technology Assessment
Recorded and Adjusted 2014-2018/Forecast 2018-2021
(Constant 2018 $000)

	Recorded					Forecast		
	2014	2015	2016	2017	2018	2019	2020	2021
Technology Assessment	$14,810	$14,243	$10,716	$14,428	$10,570	$12,954	$12,954	$12,954
Totals	**$14,810**	**$14,243**	**$10,716**	**$14,428**	**$10,570**	**$12,954**	**$12,954**	**$12,954**

1. Technology Assessment

a) Work Description

Grid Technology Assessments, Pilots & Adoptions activities include:

- Using technology to perform advanced systems studies and develop models to better understand grid operations in an ever-changing environment;
- Operating and maintaining integrated test facilities with capabilities to develop operational solutions, and safely testing and evaluating those solutions prior to deploying them in the field;
- Supporting the development of industry standards that promote equipment interoperability, vendor diversity, and prudent long-term asset deployment strategies; and
- Supporting the Distribution Resources Plan (DRP) as well as supporting the Commission's Energy Storage Mandate (the Energy Storage Mandate requires that SCE procure or build 580 MW by 2020 and bring it online by 2024);[231]

The labor expenses for these activities include payroll for engineers and management working on the activities described above. Non-labor costs include allocated overheads, small tools, equipment, and test facility operation/maintenance costs. Test facility operation/maintenance costs include activities related to the calibration, maintenance, and repair of test assets and test infrastructure, as well as costs associated with the daily operations of the test facilities. Additionally, supplemental contract personnel are also used when efforts are shorter in duration, or when unique subject expertise is required. Expenses for contract personnel are recorded as non-labor.

---

[231] D.13-10-040.

b) <u>Need for Activity</u>

SCE's distribution grid is becoming more complex, with new challenges, but also with new opportunities to use new technologies to foster clean, distributed generation resources for our customers. SCE's Grid Technology efforts play a vital role in evaluating these promising technologies in a test facility setting.

Grid Technology prioritizes its program with input from other SCE operating groups and through extensive external engagement with other entities, such as U.S. Department of Energy (DOE) National Labs, other utilities, industry research organizations, academia, and the vendor community. For each effort, we determine whether SCE's role will be to lead, participate in, or monitor testing activities. Typically, SCE leads on high-priority projects where it has the expertise and facilities capable of testing the technologies against SCE-specific operating protocols and where systems integration is potentially complex and unique to SCE's operating systems (*e.g.,* EDEF in Westminster, California).

SCE has worked with many public, private, and commercial entities in studying new technologies in order to understand integration implications and the potential ability to meet future needs of operating the grid. An example is SCE's work with the California Energy Commission (CEC), California Public Utility Commission, California Independent System Operator (CAISO), California Air Resources Board (CARB), and the Governor's Business Office to create the first California Vehicle Grid Integration (VGI) Roadmap. This effort is still ongoing, as SCE is involved in continued Roadmap revisions by participating in the California VGI Working Group to evaluate new vehicle-grid communication, control, and integration aspects. This new working group is comprised of major automakers and charging system suppliers to evaluate and pilot the promising technologies identified.

SCE also collaborates in multidisciplinary teams to address challenges associated with DER integration, modeling, and evaluation. Efforts in this area include a CEC-sponsored project involving Gridworks, Hitachi, Stanford Linear Accelerator Center (SLAC), Pacific Northwest National Lab (PNNL), Pacific Gas and Electric Company, and other members to enhance power systems analysis tools, facilitate modeling and data transfer, and enable parallel computing. This collaboration will help address problems such as hosting capacity and renewable integration. Similarly, a DOE-funded project led by Lawrence Berkeley National Lab (LBNL) and in partnership with the National Rural Electric Cooperative Association (NRECA), Packetized Energy, Vermont Electric Coop, Tesla, University of California at Berkeley, Stanford University, and the University of Vermont is expected to improve grid resilience. This project will develop a simulation tool and digital platform using artificial intelligence, machine learning, and optimization and communications methods to anticipate, withstand, and rapidly recover from potentially disruptive grid events (particularly climate or cybersecurity-related events).

Through its memberships and associations, SCE monitors the efforts of other organizations to help ensure that its methods, requirements, and processes move toward standardization, to learn from the experiences of others, and to leverage the efforts of third parties. This gives our customers much of the benefits of technology evaluation at a fraction of the cost. As an example, SCE's membership in the Electric Power Research Institute's (EPRI) Electric Transportation Program leverages the investment of more than 40 members and has helped assess technologies and study the effects of deploying certain technologies. Through our membership in EPRI's Electric Energy Storage and Distributed Generation Program, SCE continues to monitor industry best practices, standards, and guidelines for planning, procurement, deployment, operation, maintenance, and decommissioning of energy storage projects. This program is beginning to add additional value in the area of microgrids, and SCE expects over time the program should play a similar role in this area as it has for energy storage.

Additionally, in order to have the ability to complete assessments, the Grid Technology Test Facility's non-labor expenses are critical for operating the testing facility. These expenses represent:

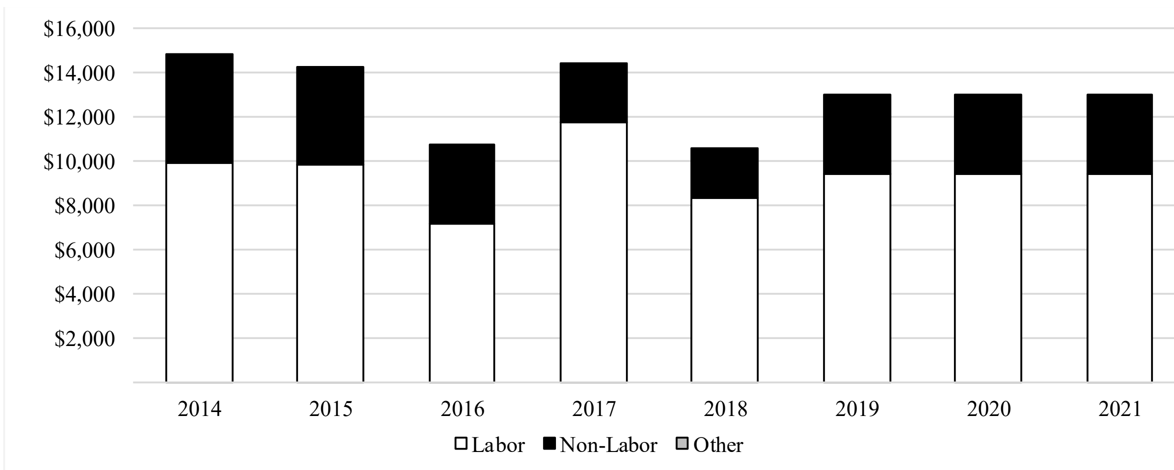
- Upkeep of the test facility test infrastructure;
- Asset maintenance (including preventative maintenance, calibration, and repairs);
- Engineering software (new and renewal of existing engineering software licenses);
- Supplies for performing the work (such as wires, fuses, and enclosure materials for tests);
- Materials handling for deploying large project assets onto testing sites; and
- Engineering design documentation and permit fees associated with integrating equipment being tested into the test infrastructure.

These expenses contribute to the facilities' ability to quickly intake and integrate projects onto the test infrastructure.

c) **Scope and Forecast Analysis**

The recorded and forecast O&M expenses for Technology Assessments are shown below in Figure III-34.

Figure III-34
Technology Assessments[232]
Recorded and Adjusted 2014-2018/Forecast 2018-2021
(Constant 2018 $000)



	Recorded					Forecast		
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Labor	$9,929	$9,789	$7,180	$11,727	$8,277	$9,381	$9,381	$9,381
Non-Labor	$4,881	$4,454	$3,537	$2,701	$2,293	$3,573	$3,573	$3,573
Other								
Total Expenses	**$14,810**	**$14,243**	**$10,716**	**$14,428**	**$10,570**	**$12,954**	**$12,954**	**$12,954**

(1) **Historical Variance Analysis**

(a) **Labor**

From 2014 to 2015, labor expenses remained relatively flat. From 2015 to 2016, there was a decrease of $2.609 million. This decrease was primarily due to labor resources being temporarily reprioritized to activities that do not record to this activity. From 2016-2017, labor expenses increased by $4.547 million due to labor resources charging to this account supporting vehicle electrification, data analytics, and grid modernization. From 2017-2018 labor expenses temporarily decreased by $3.450 million, as SCE restructured its technology-related activities in an effort to more effectively address changing and competing priorities (e.g., regulatory, legislative and technical). In

[232] Please refer to: WP SCE-02, Vol. 4, Part 1, Ch. III, Book B, pp. 1-7 - O&M Details for Technology Assessments.

anticipation of the reorganization, attrition increased above normal levels. These vacant positions along with other labor resources were allocated to other purposes as SCE awaited a final decision in its 2018 General Rate Case.

(b) <u>Non-Labor</u>

From 2014 to 2015, non-labor decreased by $427,000 as a result of resources being diverted to technology demonstration projects (that do not record to this activity) focused on identifying the technologies and controls necessary to integrate DERs. From 2015 to 2016, a decrease of $917,000 occurred as a result of a combination of company-wide Operational Excellence (OpEx) O&M cost reduction activities. This included reductions in contract work, small tools, and equipment. Additionally, non-labor resources were diverted to technology demonstration projects (that do not record to this activity) focused on proving distribution automation technologies and grid control architecture necessary to inform SCE's Grid Modernization efforts. These efforts continued in 2017, which resulted in a further $836,000 decrease from 2016 to 2017. From 2017 to 2018, a decrease of $408,000 was driven by further reductions in contract work, small tools and equipment.

(2) <u>Forecast</u>

(a) <u>Labor</u>

From 2019 to 2021, the labor forecast remains flat at $9.381 million for each year. As explained below, we utilized a five-year average of recorded 2014-2018 expenses as the basis for our technology assessments forecast.

(b) <u>Non-Labor</u>

From 2019 to 2021, the labor forecast remains flat at $3.573 million for each year. We used a five-year average of recorded 2014-2018 as the basis for our technology assessments forecast.

d) <u>Basis for O&M Cost Forecast</u>

In D.89-12-057, and subsequently in D.04.07-022, the Commission stated that if recorded expenses have significant fluctuations from year to year, an average of recorded expenses is appropriate. Here, the O&M expenses have varied from year to year. For example, the O&M expenses from 2014 to 2018 varied from a high of approximately $15.0 million to a low of approximately $10.6 million. Moreover, there was no reliable trend. From 2015 to 2016, recorded costs dropped sharply. Then, from 2016 to 2017, the costs rose sharply. From 2017 to 2018, the costs again fell sharply. The five-year average results in a reasonable 2021 Test Year forecast of $12.95 million.

D. Capital Expenditures for Test Facility Operations

1. Summary of Cost Forecast

Table III-21 below summarizes the 2014–2018 recorded and 2019–2023 forecast capital expenditures for the Grid Technologies Laboratories.

Table III-21
Grid Technologies Laboratories
2014-2018 Recorded/2019-2023 Forecast
(Total Company - Nominal $000)

	Recorded					Forecast				
Grid Technology Laboratories	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Pomona Labs	$8,819	$4,477	$2,066	$304	$899					
Westminster Labs	$1,901	$1,201	$1,013	$1,122	$65	$4,455	$6,177	$1,223	$1,126	$1,366
EDEF		$3,770	$820	$8,103	$1,634	$272	$281	$951	$1,301	$400
Vehicles			$42	$276	$46					
Total	$10,720	$9,448	$3,941	$9,805	$2,645	$4,727	$6,458	$2,174	$2,427	$1,766

2. Grid Technology Test Facility Work Description

The Grid Technology Laboratories allow us to safely evaluate, test, and pilot new and emerging technologies to deliver safety, reliability, wildfire resiliency, decarbonization, customer empowerment and affordability benefits. The facilities also provide a means to test newer versions of existing technologies to support increased operating capabilities when we are replacing equipment that has reached the end of its lifecycle. SCE maintains and operates test facilities at three locations: the Westminster Test Facility in Westminster;[233] the Pomona Test Facility[234] in Pomona; and the EDEF, also located in Westminster.

The Westminster Test Facility supports technology evaluation, proof-of-concept validations, and pre-deployment testing. This testing includes evaluating grid communications and cyber-security hardware and software, next-generation substation and distribution automation, and

[233] Formerly known as the Fenwick Labs.

[234] Formerly known as the Electric Vehicle Technical Center (EVTC), which has been continuously operated by SCE since 1993. The name change is due to the expansion of testing in the field of energy storage and electric transportation. The EVTC is approved by the U.S. Department of Energy to evaluate electric vehicle baseline performance and fleet operations. As a result of the EVTC's prominence in the industry and the importance of its work, President Obama made an extended visit to the facility in 2009.

protection equipment. Our Pomona facility tests and evaluates alternative fuel and electric vehicles, fleet vocational equipment (auxiliary support equipment our utility crews utilize once deployed to a jobsite, such as gas/diesel generators, hydraulic tools, bucket-lifts/cranes and electric power tools), and electric charging infrastructure. The Pomona facility also tests and evaluates battery storage components and their integration into grid-ready energy storage systems. EDEF performs evaluations of largely unproven emerging technologies in a high-voltage grid environment, and helps address immediate operational concerns, such as integrating intelligent sensors, communication devices, solar inverters, and energy storage.[235]

Grid Technology recently completed an examination of the Pomona Test Facility to compare its capabilities and infrastructure against what we prudently anticipate we will need in the future. As a result of this review, and in an effort to increase testing synergies and reduce costs, we will be developing an Energy Storage and Transportation Electrification (ES&TE) Test Facility at the Westminster Combined Facility (WCF) and integrating it with the Westminster Test Facility. The Pomona Test Facility will be decommissioned at the completion of the Westminster ES&TE expansion. At that point, all future testing that requires the current capabilities found at the Pomona Test Facility will take place in Westminster.

SCE compared the costs of, on the one hand, expanding the WCF by adding new ES&TE capabilities to existing high-voltage infrastructure versus, on the other hand, updating the Pomona facility with similar high-voltage testing capabilities (i.e., 12kV interconnection). SCE found that expanding the WCF is more cost-effective. By leveraging existing high-voltage test infrastructure at the WCF, utilizing existing WCF buildings, and discontinuing the maintenance and expansion of the outdated and no longer needed Pomona Test Facility equipment, SCE finds the expansion of WCF to be the more financially prudent decision.

SCE has a growing need to expand TE testing capabilities to support future unidirectional managed charging, bidirectional vehicle-to-grid, and new fast charging standards. The Grid Technology organization is nearing the start of a large TE project that will require a 12 or 16 kV distribution grid voltage interconnection. The initial plan was to expand and develop these testing capabilities at the Pomona test facilities as referenced in the 2018 GRC. An alternate to this is to utilize existing

235 Converts the variable direct current output of a photovoltaic (PV) solar panel into a utility frequency alternating current that can be fed into the grid.

infrastructure at the Large Energy Storage Test Apparatus (LESTA) facility located at the WCF, along with the new ES&TE Test Facility. LESTA cost $2.670 million (adjusted for inflation)[236] to construct and commission, and meets the majority of required TE testing capabilities. Focusing on minor reconfigurations to LESTA instead of developing a new 12 or 16kV distribution grid voltage interconnection in Pomona will be more cost-effective by $1.170 million and will better utilize our existing asset in LESTA.

Building the new ES&TE Test Facility is also advantageous as it should cost less to maintain and upgrade the space over the coming years compared to Pomona. Newly renovated and constructed spaces are less likely to require major repairs as opposed to older buildings. With the Pomona Labs operating for over 25 years, there are likely to be costly facility and test infrastructure issues that will need to be addressed. Examples of items that are currently being assessed for repair are the HVAC systems to support the test facility's heat loads, upgrading the fire suppression system due to changes with the energy storage building fire code, and building electrical upgrades because the building was constructed in the 1950s. Additionally, the new test facility's indoor test space footprint will be much more compact due to consolidating test assets and infrastructure in comparison to the existing Pomona site; this should contribute to avoided expenses in facility maintenance.

The new ES&TE Test Facility will require fewer capital improvements over the next five years as the facility will be built from the beginning with the estimated test capabilities needed during this time period. Also, since the facility will be new, there will be less need to refresh test hardware and assets. As a result, SCE estimates that the authorized 2018 GRC $1.2 million[237] average annual capital budget for the Pomona site for TE&ES testing capabilities can be reduced by $950,000 annually.

Currently there are Grid Tech personnel assigned to the Pomona Test Facility. In order to leverage their time to support other projects that require site testing in Westminster, these employees must spend significant time traveling between the various sites. This also applies to staff based in Westminster who need to utilize the Pomona Test Facility infrastructure. Consolidating test infrastructure in Westminster will allow Grid Tech to better optimize employees' time to support Grid Tech's project portfolio. Locating all employees in Westminster will also enable cross-training between

---

[236] Please refer to workpaper: WP SCE-02, Vol. 4, Pt. 1, Ch. III, Book B, pp. 8-20 – Westminster Test Facility Capital Forecast, Table 6.

[237] *See* D.19-05-020, p. 332.

former Pomona assigned staff in areas beyond ES&TE activities, as well as currently assigned Westminster staff in ES&TE activities, improving the knowledge base all around.

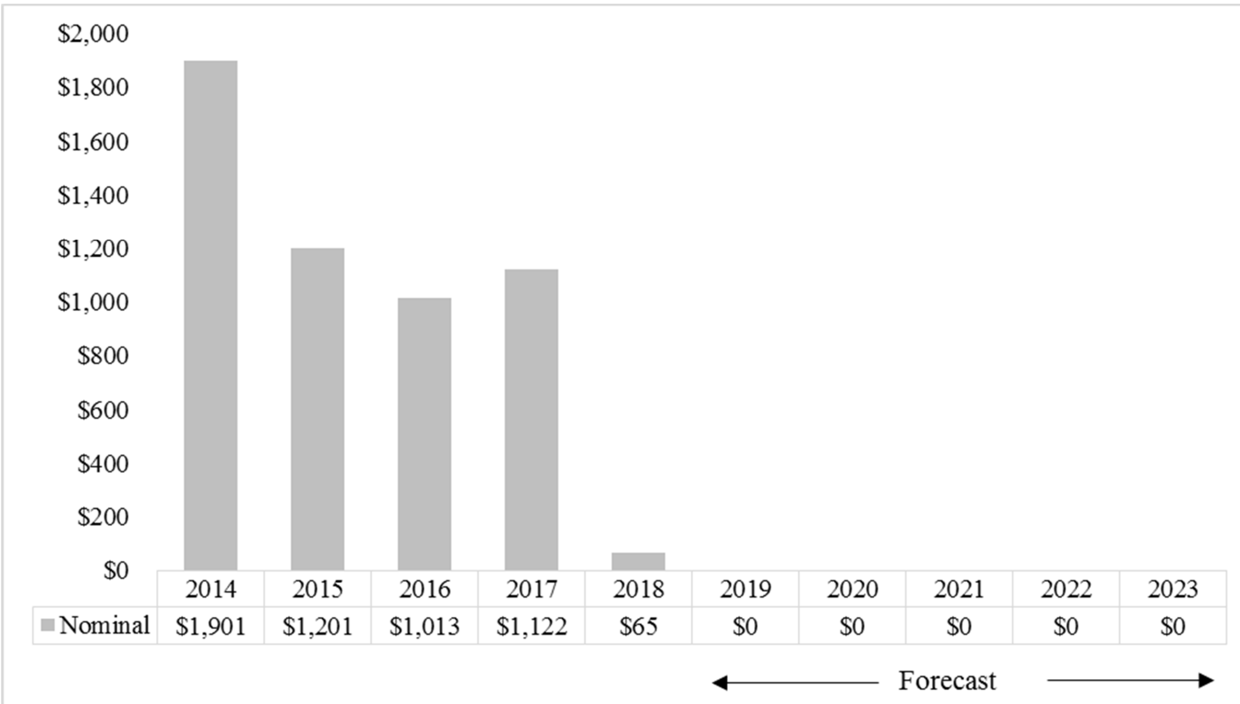
Table III-22
Cost Comparison of Expanding Pomona Test Facility vs. Upgrading WCF
(Nominal $000)

Required Capability	Pomona Test Facility	Westminster Combined Facility (WCF)	Forecasted Savings by Utilizing WCF
High voltage transportation electrification test infrastructure expansion	$2,670	$1,500	$1,170
Expansion of test infrastructure and assets to accommodate emergent technologies	$1,200	$250	$950
		Total Forecasted Savings	**$2,120**

a) <u>Pomona Test Facility Upgrades</u>

Figure III-35 summarizes the 2014–2018 recorded and 2019–2023 forecast capital expenditures for Pomona Test Facility upgrades.

Figure III-35
2014 – 2018 Recorded/2019-2023 Forecast Capital Expenditures for
Pomona Test Facility Upgrades
CWBS Element CET-OT-OT-AT-642404
(Nominal $000)



(1) **Program Description**

Since 1993, SCE has operated the Pomona Test Facility to test, evaluate, and validate the performance reliability and safety of emerging electric and hybrid vehicles and their energy storage battery technologies. The capabilities that the Pomona Test Facility provide are collectively referred to as Energy Storage and Transportation Electrification (ES&TE) testing capabilities. SCE couples electric and hybrid vehicles with stationary electric storage technologies, due to the commonality of applications. In SCE's 2018 GRC, the Commission approved the amounts SCE requested for the Pomona facility.[238] As stated in this section, SCE plans to build out new essential ES&TE test capabilities at Westminster in order to reduce the cost to deliver, operate and maintain necessary test capabilities.

[238] *See* D.19-05-020, p. 332, fn. 777.

(2) Need for Capital Program

Grid Technology assessed the Pomona Test Facility to identify the testing capabilities and infrastructure that will be required in the future. As a result of this assessment, and in an effort to increase testing synergies and reduce costs,[239] we will be expanding WCF with an ES&TE Test Facility that will be integrated with the existing Westminster test spaces.[240]

(3) Basis for Capital Expenditure Forecast

As shown in Figure III-35 above, SCE forecasts the total cost of the Pomona capital request will be $0 from 2019-2023, as forecast costs for Pomona upgrades have been integrated into the Westminster Test Facility upgrades.

b) Westminster Test Facility Upgrades

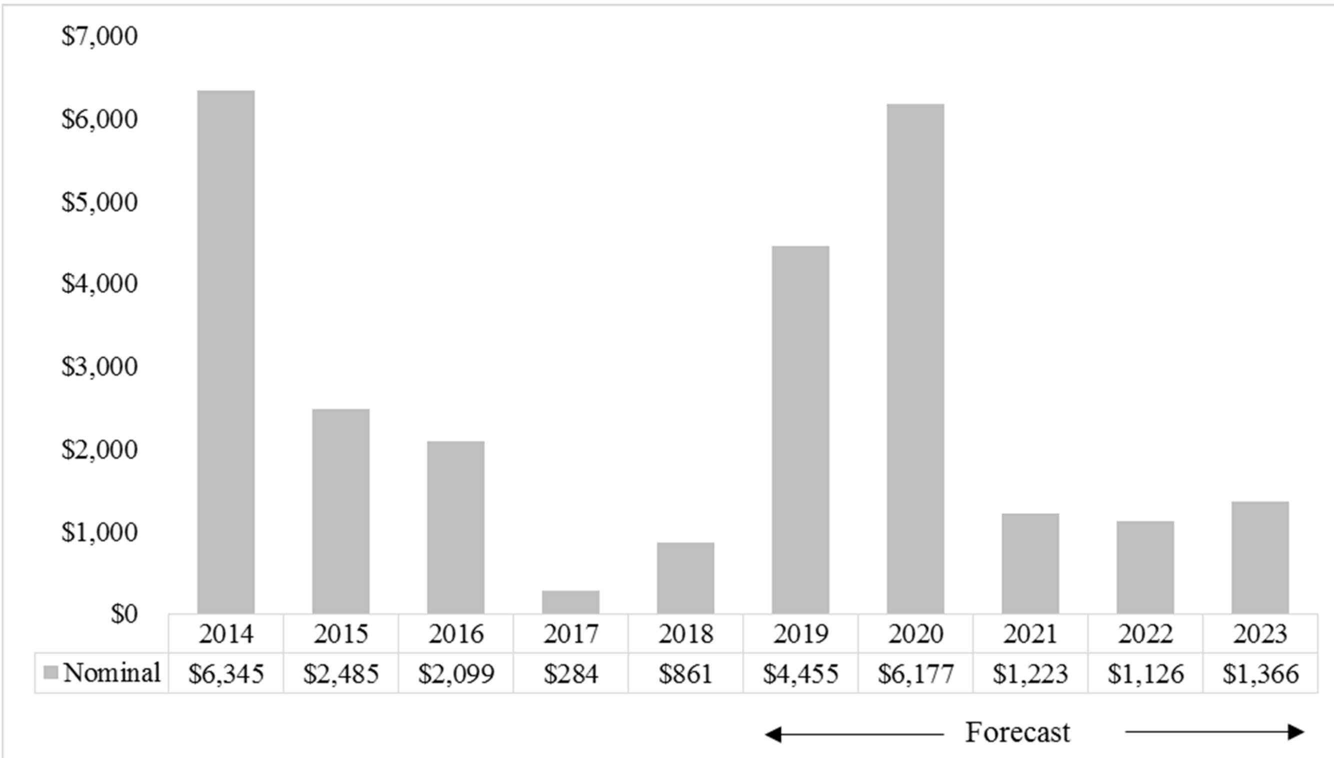
Figure III-36 below summarizes the 2014–2018 recorded and 2019–2023 forecast capital expenditures for Westminster Test Facility upgrades.

---

[239] Please refer to workpaper: WP SCE-02, Vol. 4, Pt. 1, Ch. III, Book B, pp. 8-20 - Westminster Test Facility Capital Forecast, Table 5.

[240] Please refer to workpaper: WP SCE-02, Vol. 4, Pt. 1, Ch. III, Book B, pp. 8-20 – Westminster Test Facility Capital Forecast, Table 4, “Energy Storage and Transportation Electrification Test Facility Expansion.”

Figure III-36
2014 – 2018 Recorded/2019-2023 Forecast Capital Expenditures for Westminster Test Facility Upgrades[241]
CWBS Element CET-OT-OT-AT-642400
(Nominal $000)



(1) <u>Program Description</u>

The Grid Technology Westminster Test Facility gives our engineers various test capabilities and assets to safely evaluate and test emerging technologies in fully integrated grid environments. To identify and determine which technological solutions will help advance the power grid with clean resources, while maintaining safety and reliability, SCE will continue to:

- Evaluate the business need for new technologies;
- Test the technology components in the laboratories to determine whether they can withstand the requirements of grid operations;

[241] Please refer to: WP SCE-02 Vol. 4 Part 1, Ch. III, Book B, pp. 21-22 - Capital Details by WBS for Westminster Test Facility Upgrades.

- Determine the broader equipment capabilities in a controlled environment without affecting service to our customers;
- Pilot the combined systems on SCE's grid to determine their ability to perform under actual conditions; and
- Deploy technological integration solutions.

The Westminster Test Facility was first constructed in 2010. The Westminster Test Facility became fully operational in 2011, and under approval by the Commission[242] has been in continuous operation since then. We plan to test infrastructure expansions and capabilities to prudently address contemporary grid operation complexities.[243] The names of the 11 interconnected test spaces located at the Westminster Test Facility and their descriptions and capabilities can be found in our Grid Technology workpapers.[244]

While each space in the Westminster Test Facility has a testing and evaluation element, the facility is interconnected to allow testing across the entire electric system supply chain – generation, transmission, distribution, and behind-the-meter devices. The Westminster Test Facility continues to support technology evaluation, proof-of-concept validations and pre-deployment testing. This GRC request will allow the Westminster Test Facility to acquire new equipment, refresh older equipment, and expand the capabilities of the test facility.

(2) <u>Need for Capital Program</u>

The 2021 GRC request for the Westminster Test Facility includes expanding select test spaces to include new and updated test infrastructure. The request also encompasses hardware asset expansion, testing, and refresh to make sure that the testing capabilities will continue to meet current and emerging testing needs. This request can be found in our Grid Technology workpapers.[245] As we note in the workpaper, the expansions focus on select test spaces that are due for upgrades, and reconfigurations to support future testing. Our work here includes: (a) adding capabilities and making improvements in test spaces; (b) performing hardware refresh updates; and (c) developing

---

[242] *See* D.15-11-021, p. 50.

[243] Such complexities include meeting customer choice needs with grid-connected generation and other technologies, and addressing wildfire challenges.

[244] Please refer to workpaper: WP SCE-02, Vol. 4, Pt. 1, Ch. III, Book B, pp. 8-20 - Westminster Test Facility Capital Forecast, Table 1.

[245] Please refer to workpaper: WP SCE-02, Vol. 4, Pt. 1, Ch. III, Book B, pp. 8-20 - Westminster Test Facility Capital Forecast, Table 4.

new test infrastructure not yet available in the Westminster Test Facility that will be interconnected with the existing test spaces.

The new infrastructure includes additional power capabilities, conduits, electrical service panels, and new service capabilities to support the additional load triggered by the equipment being tested in the labs. The new infrastructure also adds high sampling and precision data acquisition sensors and devices to the test spaces. This will let us collect even better quality data. Our reconfiguration work encompasses retooling existing lab spaces to provide more testing capabilities and a greater testing "footprint" so that we can interconnect additional equipment-under-test to the test space infrastructure.

Safety is also driving the reconfiguration. The current test spaces are over-encumbered. A larger testing footprint is needed so that we can safely test and evaluate the equipment we plan to assess.

(3) Basis for Capital Expenditure Forecast

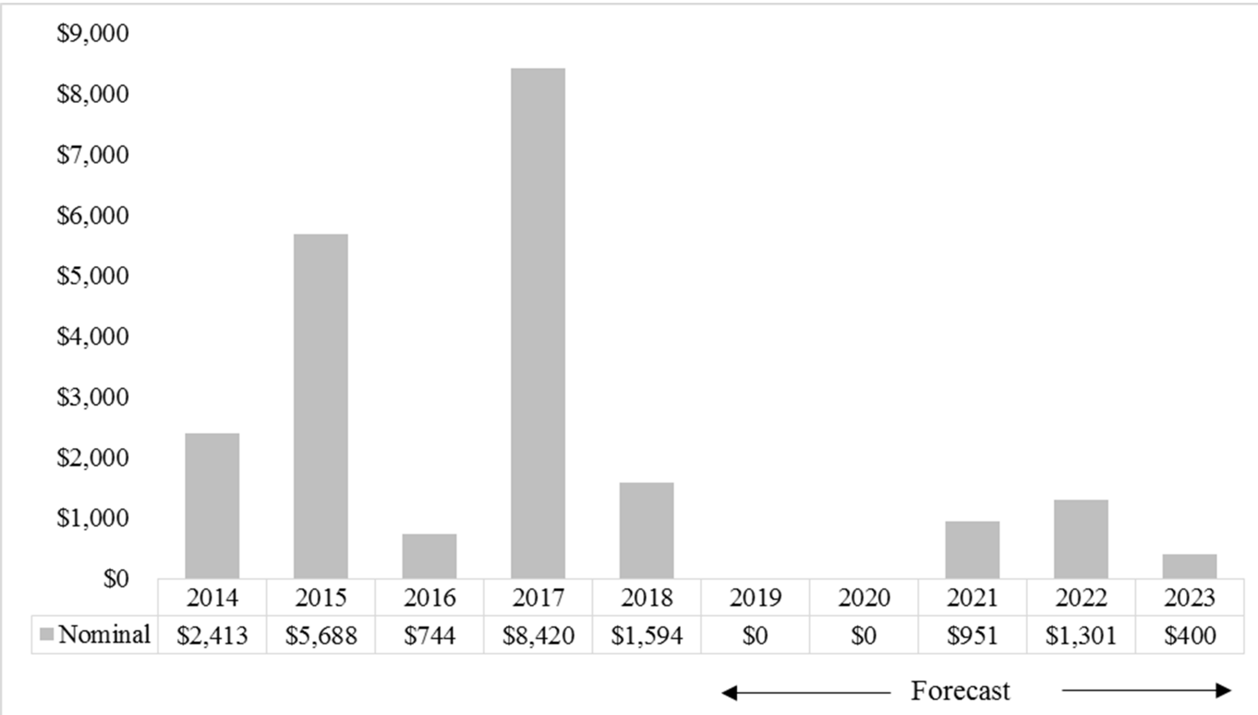
As shown in Figure III-36, SCE forecasts the total cost of enhancements to the Westminster Test Facility to be $14,348 million from 2019-2023. These estimates were developed using existing contracts, recent purchases and accounting/engineering estimates. Each enhancement provides the test infrastructure necessary to evaluate planned and future Grid Modernization and Resiliency technologies. The new test infrastructure will also be used to support EPIC III testing for products designed to be deployed in grid environments to further support safety, reliability, and wildfire mitigation capability. Further details outlining costs at each individual test space and category of enhancement can be found in the Grid Technology Westminster workpapers.[246]

c) EDEF Upgrades

Figure III-37 below summarizes the 2014–2018 recorded and 2019–2023 forecast capital expenditures for EDEF upgrades.

[246] Please refer to workpaper: WP SCE-02, Vol. 4, Pt. 1, Ch. III, Book B, pp. 8-20 - Westminster Test Facility Capital Forecast, Table 3 and Tables 7–17.

Figure III-37
2014 – 2018 Recorded/2019-2023 Forecast Capital Expenditures for EDEF Upgrades[247]
CWBS Element CET-OT-OT-AT-642419
(Nominal $000)



(1) Program Description

EDEF is a high-voltage test facility located adjacent to an existing SCE substation that was built to test a variety of new technologies to support renewables integration, grid modernization, infrastructure replacement, safety enhancements, and grid resiliency. EDEF allows SCE engineers to evaluate largely unproven emerging technologies on energized high-voltage equipment and distribution circuits for rapid deployment without negatively impacting public safety or system reliability. This unique capability gives SCE the benefit of conducting high-voltage evaluations under real-world conditions that mimic observed grid events that are widespread and unique on SCE's distribution grid. Conducting these evaluations are crucial to determining operational successes and failures before we deploy the technologies.

[247] Please refer to: WP SCE-02 Vol. 4 Part 1, Ch. III, Book B, pp. 23-24 - Capital Details by WBS for EDEF Upgrades.

EDEF is what gives SCE the ability to test on a 12 kV circuit. Currently this platform is configured for quick deployment of any 12 kV distribution apparatus and hardware. This has been used in the past to test automation schemes, high impedance fault testing hardware, real-time health diagnostic testing, covered conductor, and overhead and underground fault indicators. Future testing also includes utilizing the 12 kV test circuit to perform Extreme Fast Charging (XFC) to evaluate and mitigate the impact of large-scale heavy-duty vehicle charging on the grid to maintain service reliability, improve situational awareness, and improve public safety.

(2) <u>Need for Capital Program</u>

The 2021 GRC request for the EDEF only includes expansion of capabilities by adding new test asset hardware to meet current and emergent testing needs. This request includes:

Test asset hardware expansion (2021 to 2022):

- Distributed Energy Storage Evaluation Facility Interconnection and Upgrades – SCE plans to upgrade the Shawnee Substation and the Braves 12 kV test circuit in order to be able to dispatch an energy storage system into the EDEF test circuit. These upgrades include adding an energy storage interconnection point at EDEF, and a new transformer at Shawnee Substation. It was recently found that Shawnee Substation was not able to support energy storage dispatching due to limitations of the substation transformer. This planned upgrade to the test infrastructure not only provides EDEF with the ability to dispatch energy storage into the Braves 12 kV EDEF test circuit, but will also facilitate future load growth potential and allow customers connected to Shawnee Substation to install more distributed energy resources.

Test asset hardware expansion (2021 to 2023):

- EDEF High-Voltage Test Circuit Hardware – EDEF's current test capabilities will be expanded from 2021 to 2023 to position SCE for future resiliency and reliability technology testing and evaluation. Our current plans are to build a test platform for what SCE is calling an

Intelligent Modern Pole[248] to complete the evaluation of this new product. Also scheduled are installing new non-standard higher interrupting automatic reclosures for deployment evaluation.

- EDEF Energy Storage System – The EDEF test circuit not only utilizes a real 12 kV distribution circuit, but it also has dedicated energy storage integration capabilities. We currently are in the process of interconnecting a 500 kW, 2 MWh energy storage system in order to be able to inject real energy storage profiles into the test circuit when performing testing on equipment that will be supporting DER capabilities. This system was relocated from a different circuit in order to keep costs down, and requires upgrades to the site electrical service (switchgear, transformers, relays, and protection devices) in order to complete the interconnection to the Braves 12 kV test circuit and safely operate the energy storage system. This system is not for market use and will be solely used as a test apparatus for testing on the EDEF 12 kV test circuit.
- DER Inverter Capability Enhancement – The EDEF DER testing capabilities will be enhanced over the next four years to be able to test advancements in DER technologies, as well as the management of the forecast high rate of DER adoption from our customers. These enhancements will include installing a PV system in order to assess smart DER technologies, such as smart solar PV inverters and smart energy storage solutions on distribution environments.
- Tie-Switch Test Capability Enhancement – The penetration of DER technologies will change distribution circuit impedances that can cause issues on Tie-Switches when they are operated. The performance of these switches will be evaluated when subject to different voltage phase angles across the switch before re-closure. So that we can evaluate the impact of DERs on Tie-Switches, we will install grid

[248] The Intelligent Modern Pole is explained earlier in this testimony.

simulation hardware to simulate loop circuits where they will have different phase angles and Tie-Switches.

- DER Voltage Regulator Enhancement – The rise of DER technologies on the grid will dynamically change the grid power flow during the day, depending on the penetration levels and local load conditions. Bi-directional power flows will need to be properly evaluated on voltage regulators so that proper settings can be implemented when installed in the field. In order to properly assess this issue, we will be installing a voltage regulator and utilize grid simulators to simulate circuit power flow.
- Distribution Micro-Grid Circuit Enhancement – The penetration of micro-grids in SCE service territory is likely to increase. The potential rise in micro-grids may need distribution equipment technologies to be evaluated when a planned micro-grid is established or when an emergency micro-grid condition is needed in order to keep serving customers during abnormal conditions. In order to test and evaluate distribution equipment in these micro-grid conditions, we will be installing distribution switches and protection devices on the EDEF test platform that will integrate with the EDEF to create a distribution micro-grid test platform to assess these conditions and technology.
- Underground Fault Detection Enhancement – Catastrophic faults in underground cables are a high liability for SCE. Safety and customer/utility equipment integrity can be compromised. Underground cable technologies can be evaluated at EDEF to assess their performance. We plan to add an underground fault detection capability that will include installing high fidelity and high sampling data acquisition tools as well as a high voltage potential tester.
- Substation Environment Upgrades – The proximity of EDEF to an active SCE substation makes it ideal to test substation equipment as the environment is closer to that observed in the field. A Process Bus test platform will be installed in order to test Process Bus technology

in an environment that is nearly identical to a substation. This environment will make use of EDEF's 12 kV test circuit so test hardware can be integrated and evaluated with real high-voltage environments.

(3) Basis for Capital Expenditure Forecast

As shown in Figure III-37, SCE forecasts the total cost of EDEF Capital request will be $2.652 million from 2019-2023. These estimates were developed using existing contracts, recent purchases, and accounting/engineering estimates. Each enhancement is based on updating test infrastructure to support testing and evaluating of existing and future Grid Modernization and Grid Resiliency technologies. The new test infrastructure will also be used to support EPIC III testing for products designed to be deployed in grid environments to further support safety, reliability, and wildfire mitigation technologies. Further details outlining costs for each type of upgrade within EDEF can be found in the Grid Technology EDEF workpapers.[249]

SCE accepts the Commission's decision to disallow recovery of the construction costs associated with EDEF in the 2015 and 2018 rate case decisions, but SCE still believes EDEF provides unique and essential testing capabilities more cost-effectively than contracting with vendors or research institutions. To determine the most cost-effective option, SCE conducted a Request for Proposal (RFP),[250] which is a common process used by supply chain management operations to source and procure services. SCE did so to determine the market cost for providing desired EDEF testing capabilities and supporting future projects requiring these capabilities.

SCE's RFP was distributed to 17 vendors who have experience with high-voltage utility distribution grid projects. Only nine of the 17 vendors indicated interest in the RFP by updating their vendor profiles in SCE's vendor management system (ARIBA), and only one of those nine responded with a bid. The other eight vendors stated that they did not have the capabilities that SCE was seeking, were not interested, or dropped out of the process by failing to respond. As discussed below, the one

---

[249] Please refer to workpaper: WP SCE-02, Vol. 4, Pt. 1, Ch. III, Book B, pp. 25-29 - EDEF Capital Forecast, Tables 2–11.

[250] Please refer to workpaper: WP SCE-02, Vol. 4, Pt. 1, Ch. III, Book B, pp. 30-61 - EDEF Test Facility Infrastructure Cost-Comparison, RFP Lab Capabilities – Statement of Work – Confidential (Redacted) / WP SCE-02, Vol. 4, Pt. 1, Ch. IIIC - pp. 1-32.

vendor that did respond was shown to be able to perform most, but not all, of the capabilities that SCE is seeking.

As shown in the workpaper,[251] *the RFP validated that it is more cost-effective for SCE to continue upgrading EDEF and conducting in-house testing rather than contracting the same scope of work to a third party*.

SCE standardized assumptions in order to compare the vendor's proposal versus SCE's EDEF upgrade request in an equal and consistent manner. The first assumption involved matching SCE's project testing schedule with the vendor's proposed three-year testing schedule, even though it may not be feasible or realistic to perform the required tests in this timeline.[252] The second assumption involved test labor needed during the vendor's proposed schedule, as the vendor's response included facility use and labor based on time and material. While SCE's EDEF upgrade request does not reflect test labor since these resources are already included in the Technology Assessment O&M labor request, SCE included internal test labor[253] in the cost comparison analysis and made the following assumptions:

- Grid Technology resources allocating 300 hours per year for EDEF testing then adjusted per quarter to match the vendor's proposal:
    - Senior Engineer
    - Technical Specialist, Senior Advisor
    - Lab Services, Advisor
    - Lab Services, Senior Specialist
- Apparatus and Standards Engineering resource allocating 150 hours per year for EDEF testing then adjusted per quarter to match the vendor's proposal:
    - Senior Engineer

[251] Please refer to workpaper: WP SCE-02, Vol. 4, Pt. 1, Ch. III, Book B, pp. 30-61 - EDEF Test Facility Infrastructure Cost-Comparison, Table 1 – Confidential (Redacted) / WP SCE-02, Vol. 04, Pt. 1, Ch. IIIC - pp. 1-32.

[252] Please refer to workpaper: WP SCE-02, Vol. 4, Pt. 1, Ch. III, Book B, pp. 30-61 - EDEF Test Facility Infrastructure Cost-Comparison, Figures 1-2 and Table 2 – Confidential (Redacted) / WP SCE-02, Vol. 04, Pt. 1, Ch. IIIC - pp. 1-32.

[253] Please refer to workpaper: WP SCE-02, Vol. 4, Pt. 1, Ch. III, Book B, pp. 30-61 - EDEF Test Facility Infrastructure Cost-Comparison, Table 3 – Confidential (Redacted) / WP SCE-02, Vol. 04, Pt. 1, Ch. IIIC - pp. 1-32.

While the vendor included their own test labor in the proposal, SCE will still need to send engineers to the vendor's site to help ensure data integrity and validate testing results.[254] The following cost assumptions were added to the vendor's proposal for the cost comparison analysis:

- Grid Tech Senior Engineer allocating 400 hours for testing and traveling to a vendor's test facility per year, then adjusted per quarter to match the vendor's proposal;
- Apparatus and Standards Engineering Senior Engineer allocating 200 hours for testing and traveling to a vendor's test facility per year, then adjusted per quarter to match the vendor's proposal; and
- Expenses of flights, lodging, meals, and car rental will be required per year, then adjusted per quarter

After standardizing across all of the assumptions, the cost comparison analysis demonstrates that upgrading EDEF and performing in-house testing costs 7.2% less than outsourcing the same scope of work to a technically qualified third-party test facility.

The RFP process also shows that EDEF's capabilities are unique and that only one vendor from the originally identified 17 vendors is even able to meet many, but not all, of SCE's required testing capabilities. The high-voltage underground technical testing capability that EDEF currently possesses, but the responsive vendor is not able to provide, is important for supporting Grid Technology's portfolio of demonstration projects. SCE did not exclude from the cost comparison analysis the $952,000 capital request for further enhancing this capability and the addition of pad-mount equipment testing at EDEF, meaning that the financial analysis could have been even more favorable towards upgrading EDEF and performing the testing in-house.[255] The cost comparison also did not include service taxes, which are estimated at 12% (5% Goods and Service Tax plus 7% Provisional Sales Tax) since the vendor is located in Canada.

---

[254] Please refer to workpaper: WP SCE-02, Vol. 4, Pt. 1, Ch. III, Book B, pp. 30-61 - EDEF Test Facility Infrastructure Cost-Comparison, Table 4 – Confidential (Redacted) / WP SCE-02, Vol. 4, Pt. 1, Ch. IIIC - pp. 1-32.

[255] Please refer to workpaper: WP SCE-02, Vol. 4, Pt. 1, Ch. III, Book B, pp. 30-61 - EDEF Test Facility Infrastructure Cost-Comparison, Table 5 – Confidential (Redacted) / WP SCE-02, Vol. 4, Pt. 1, Ch. IIIC - pp. 1-32.

Since the vendor's test facility is located outside of the United States, additional cybersecurity and information governance data restrictions may be necessary, particularly if NERC, NERC/CIP, CEII, or other confidential data is involved. Utilizing an international test facility would also limit our ability to collaborate with various U.S. government organizations such as the Department of Energy (DOE) and Department of Defense (DOD), as non-U.S. based test facilities and personnel are not allowed to participate. This would result in limited cost-sharing opportunities; such cost-sharing opportunities deliver technology-related benefits to ratepayers at reduced costs.[256] Lastly, utilizing a test facility outside of Southern California would entail customer money being spent in Canada rather than in the Southern California disadvantaged community (DAC) where EDEF is located.[257]

[256] Irvine Smart Grid Demonstration, LA AFB Base V2G Pilot Technical Evaluation, and Electric Access Service Enhancement Project all expanded SCE's knowledge of distributed energy resources such as EV, rooftop solar, community energy storage systems, distributed energy storage, and vehicle-to-grid applications.

[257] Disadvantaged communities map available at https://oehha.ca.gov/calenviroscreen/sb535, test facilities located in Westminster and Pomona as of August 14, 2019.

IV.

ENERGY STORAGE

A. Overview

The activities SCE completes under the Energy Storage BPE should help transform our grid, supporting reliability and enabling more widespread use of renewable resources. The BPE includes (1) the Distributed Energy Storage Integration (DESI) pilot systems that support learning related to the integration of grid-scale storage and (2) the Mira Loma systems deployed in direct response to Commission Resolution E-4791 to support reliability.

SCE is conducting DESI pilots to better understand energy storage use cases, performance, and cost-competitiveness. Across California, integration of energy storage into utility operations is still evolving. The DESI pilots are connected to the distribution grid to determine how these systems can provide support, as the operating environment changes, and potentially increase the value of Distributed Energy Resources (DERs), by mitigating any negative impacts. Such piloting helps SCE safely and reliably integrate energy storage systems, both utility and third-party owned, onto the grid.

SCE continues to operate the Mira Loma energy storage systems built as directed by the Commission in Resolution E-4791,[258] pursuant to Governor Brown's State of Emergency Proclamation,[259] to "take all actions necessary to ensure the continued reliability of natural gas and electricity supplies in the coming months during the moratorium on gas injections into the Aliso Canyon Storage Facility."[260] Resolution E-4791, among other things, deemed it reasonable for SCE to pursue Resource Adequacy (RA) eligible, utility owned, turnkey, in-front-of-the-meter (IFOM) energy storage projects at SCE's substations or on utility-owned or operated sites south of Path 26.[261] Two Tesla battery systems, Mira Loma Battery Energy Storage Systems A & B, also referenced as Mira Loma units 2 and

---

[258] Resolution E-4791 authorized expedited procurement of storage resources to ensure electric reliability in the Los Angeles Basin due to limited operations of the Aliso Canyon Gas Storage Facility.

[259] On January 6, 2016, Governor Jerry Brown issued a Proclamation of a State of Emergency. Paragraph 10 states that the "[CPUC] and the California Energy Commission, in coordination with the California Independent System Operator, shall take all actions necessary to ensure the continued reliability of natural gas and electricity supplies in the coming months during the moratorium on gas injections into the Aliso Canyon Storage Facility."

[260] Resolution E-4791 at p. 3.

[261] Resolution E-4791 at p. 12.e.

3, were sited adjacent to SCE's Mira Loma Peaker Generating Station and Mira Loma substation in Ontario, California and placed in service in December 2016.

1. Regulatory Background/Policies Driving SCE's Request

The Commission's Energy Storage Procurement Framework and Design Program Decision (Decision)[262] set a goal to transform the energy storage market to overcome the barriers that are hindering broader adoption of emerging technologies. This Decision established three guiding principles for the Commission's energy storage procurement policy, which in turn have become guiding principles for the DESI pilots:

1. Optimize the grid, including peak reduction, contribution to reliability needs, or deferment of transmission and distribution upgrade investments;

2. Integrate renewable energy; and

3. Reduce greenhouse gas emissions by year 2050 to 80 percent below 1990 levels.[263]

The guiding principles have resulted in DESI pilots in the categories of: (1) Distribution Reliability, (2) Facilitation of Preferred Resources, (3) Grid Resiliency, Reliability, and Electrification, and (4) Resilience Partnerships through Microgrids. Testimony below further defines the use cases and learning targeted by the DESI pilots.

2. Compliance Requirements

Driven by Governor Brown's Emergency Proclamation and the resulting Commission Resolution E-4791, which directed SCE to procure energy storage, SCE built the Mira Loma Battery Energy Storage Systems A & B. As discussed in SCE-05 Vol. 01, in D. 18-06-009, Decision Granting Cost Recovery for Utility-Owned Energy Storage Projects Pursuant to Resolution E-4791, the Commission granted the application of SCE for authority to recover the recorded and forecast costs of the Mira Loma Battery Energy Storage Systems A & B. SCE was authorized to record the Mira Loma Battery Energy Storage Systems A & B actual revenue requirements in the approved Aliso Canyon Energy Storage Balancing Account (ACESBA). The ACESBA was to be used until the remaining cost recovery was transitioned to SCE's GRC base rates in SCE's 2021 GRC.[264] SCE seeks to transition the

---

[262] Decision (D.)13-10-040.

[263] *Id*. at pp. 9-10.

[264] D.18-06-009, pp. 42 – Conclusion of Law #2.

Mira Loma projects O&M forecast into base rates effective 2021.[265] O&M costs associated with the Mira Loma Battery Energy Storage Systems A & B were originally captured as Energy Storage Initiative spend and later recorded to the ACESBA. There is discussion to reflect the funds being moved in the Historical Variance discussion for the Energy Storage Initiative in a later section of the testimony.

B. 2018 Decision

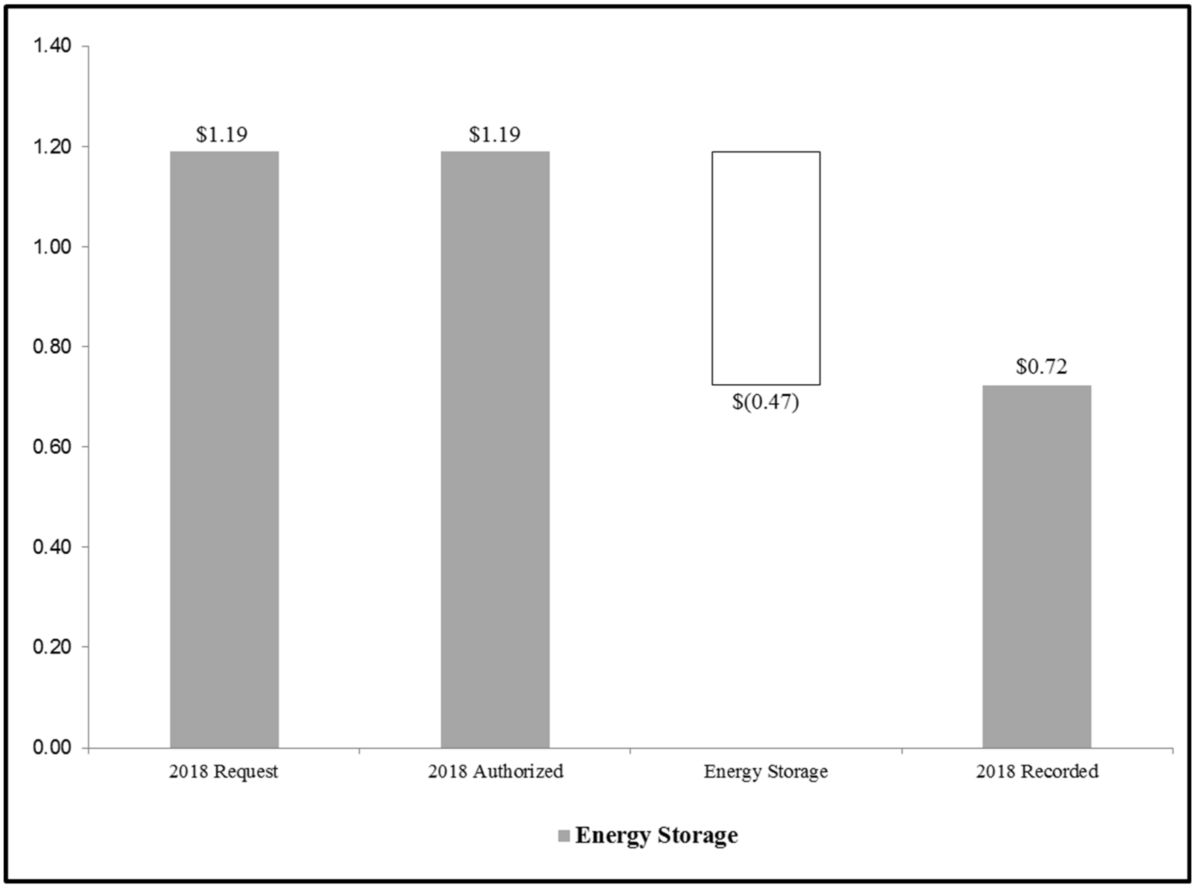
1. Comparison of Authorized 2018 to Recorded

The 2018 GRC Decision requires SCE to compare the 2018 authorized amounts to the recorded amounts;[266] Figure IV-38 and Figure IV-39 below compare amounts for O&M expenses and capital expenditures.

[265] *See* SCE-07 Vol. 1 Pt.1 (Results of Operations) Chapter IV (F) (2b) - Elimination of the Aliso Canyon Energy Storage UOG Balancing Account.

[266] D.19-05-020, Ordering Paragraph 22, pp. 441-442.

Figure IV-38
***Energy Storage*[267]**
***2018 GRC Authorized Variance Summary 2018 O&M*[268]**
(Constant 2018 $Millions)



In 2018, the Energy Storage O&M was underspent by $470,000. Recorded spending deviated from the Authorized amount due to the following reasons:

- The 2018 GRC request assumed three projects (DESI 2, DESI 3, and Horoscope) would be operational in 2017 and would incur O&M expenses in 2018. SCE

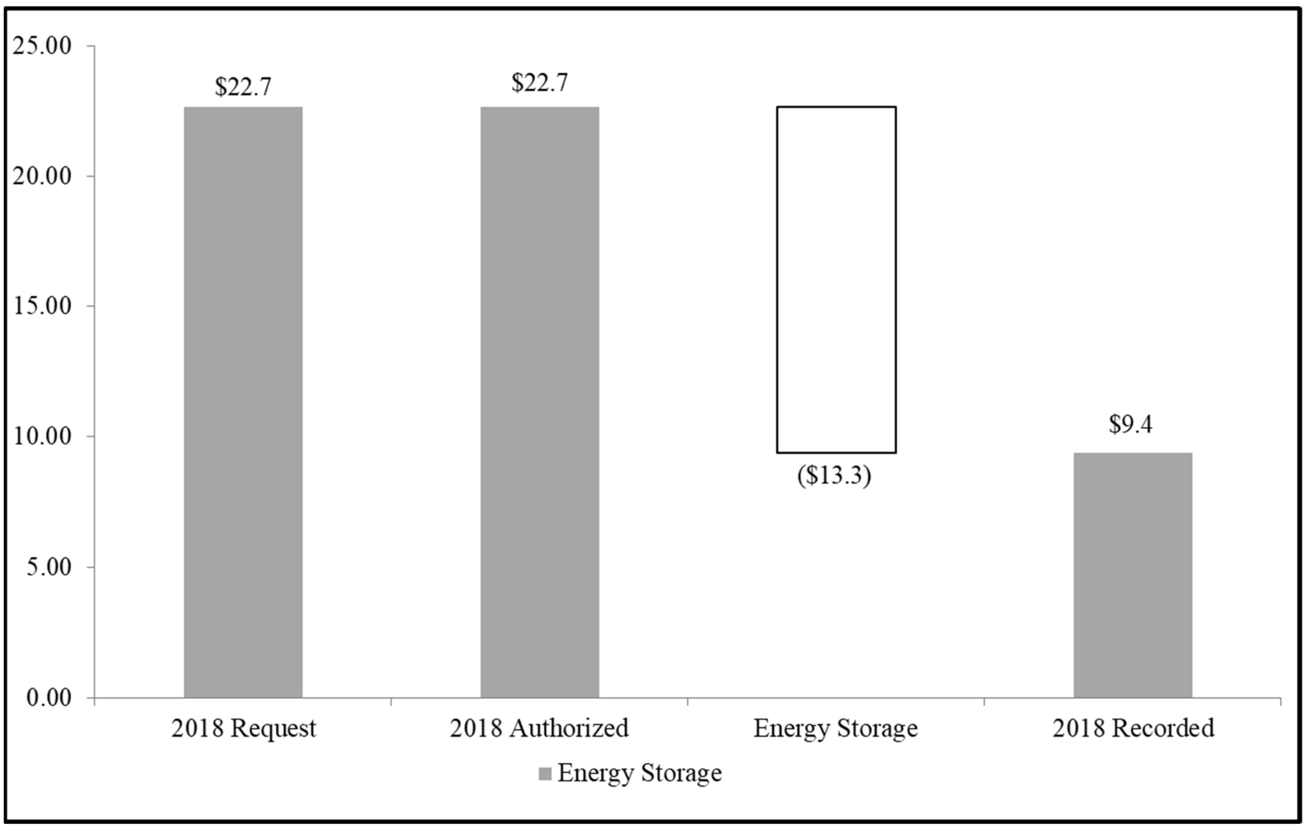
[267] Please refer to workpaper: WP SCE-07, Vol. 01. – O&M Authorized to Recorded.

[268] The 2018 recorded costs excludes $400,000 for the Mira Loma Battery Energy Storage Systems that were recovered in the ACESBA and not authorized in the 2018 GRC. The 2021 Test Year includes these costs as described in SCE-07 Vol 1 - Elimination of the Aliso Canyon Energy Storage UOG Balancing Account (ACESBA).

cancelled DESI 3 due to unavailability of land in the Preferred Resources Pilot (PRP) project area. SCE cancelled Horoscope due to changing need (i.e., there was no longer a forecasted duct bank violation[269] to justify the project). DESI 2 was delayed and went online at the end of 2018.

- Labor resources were focused on project execution in 2018 to get DESI 2 and Mercury 4 online.

Figure IV-39
Energy Storage[270]
2018 GRC Authorized Variance Summary 2018 Capital
(Total Company - Nominal $Millions)



In 2018, the Energy Storage capital was underspent by $13.3 million. Recorded spending deviated from the authorized amount because:

---

[269] A duct bank violation is when the underground cable temperature of a circuit exceeds its rating.

[270] Please refer to workpaper: WP SCE-07, Vol. 1. – Capital Authorized to Recorded

- SCE cancelled DESI 3 and Horoscope. No replacements are proposed because the targeted lessons learned will be achieved via Mercury 1 and Mercury 2.
- In 2016 and 2017, SCE focused labor resources on the expedited deployment of Mira Loma Battery Energy Storage Systems, which delayed planning efforts on DESI pilots.
- In 2017, SCE released an RFP to incorporate lessons learned so far into new contracts with improved technical requirements and balance of plant scope.
- In 2018, new California Fire Code language pertaining specifically to stationary battery energy storage went into effect and the team needed time to determine project impacts and incorporate new design requirements.
- Absent a 2018 GRC Decision, SCE slowed DESI pilot spending, due to uncertainty about whether the Commission would approve 2018 spending for the pilot.

C. O&M Forecast

Table IV-23 summarizes the energy storage recorded and forecast O&M expenses, including DESI and Mira Loma Battery Energy Storage Systems.

Table IV-23
Energy Storage
Recorded and Adjusted 2014-2018/Forecast 2018-2021[271]
(Constant 2018 $000)[272]

	Recorded					Forecast		
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Enegy Storage Initiative		$1,205	$1,881	$1,384	$723	$960	$1,170	$1,413
Mira Loma Tesla A and B Energy Storage				$645	$400	$1,100	$431	$431
Totals		**$1,205**	**$1,881**	**$2,029**	**$1,123**	**$2,060**	**$1,601**	**$1,844**

1. Energy Storage

a) Work Description

The O&M request supports planning and operations of the DESI program, including technology assessment and technology transfer (e.g., documentation and implementation of

[271] Please refer to workpaper: WP SCE-02, Vol. 4, Pt. 1, Ch. IV – Book B - pp. 62 - 68 – O&M details for Energy Storage Initiative.

[272] The Mira Loma Energy Storage O&M historical expenses in 2017 – 2018 and forecast expenditures in 2019 and 2020 still record to the ACESBA as described in SCE-05 Vol. 1. The 2021 Test Year forecast of $431,000 will be included in SCE's 2021 GRC request.

lessons learned). DESI is focused on piloting new capabilities enabled by energy storage technology and validating associated benefit streams. This program facilitates the integration of DERs into the electric system. It also provides a platform for developing tools and methods to identify where (by defining criteria for potential project locations, both from a physical land use and an electrical grid perspective) and specify how energy storage systems can add value for our customers (e.g., by defining the use case and benefits, such as renewables integration and reliability functions). DESI pilots are focused on learning aligned with the Commission's Energy Storage guiding principles. DESI also supports the development of (1) standardized integration processes and procedures and (2) validation of the ability of energy storage to serve grid operations functions, respectively. DESI clarifies how existing interconnection processes apply to a new type of asset (i.e., working through challenges of a process meant for a generating asset when energy storage is both a generator and a consumer) and establishing engineering specifications that will ensure future storage projects are safely and cost-effectively implemented (i.e., through the refinement of processes and specifications for competitive procurement). SCE Grid Operations uses energy storage systems built through DESI to manage distribution circuit loading and voltage in new ways that will be more common in the future.

The O&M request for the Tesla Energy Battery system will support the ongoing standard annual maintenance of the systems performed by Tesla, which includes equipment inspections, parts replacement, and cleaning and five-year maintenance including refilling of fluids and parts replacement. Tesla will augment the systems as needed with additional Powerpacks in order to maintain the available capacity and meet the contract's performance guarantee. Tesla will also perform additional maintenance as needed.

b) <u>Need for Activity</u>

In the 2019-2023 timeframe, SCE forecasts the O&M expense[273] required to properly maintain the DESI pilots; three already in operation and eight more that are planned for installation in 2019-2021 (to achieve the learning discussed in Section IV.D.1.a).

The DESI pilots have and will provide needed data and lessons learned to support the Commission's energy storage policy goals, while helping ensure that integrating energy storage does not diminish safety and reliability for our customers or workers. The pilots achieve these goals by

[273] Please refer to workpaper: WP SCE-02, Vol. 4, Pt. 1, Ch. IV – Book B - pp. 69 - 70 - DESI Pilot Program O&M Workpaper.

providing SCE with hands-on experience in operating energy storage systems with the added flexibility to operate the systems as needed prior to wide-scale deployment.

SCE must own and operate the DESI pilots in order to gain in-depth knowledge and experience needed to integrate such systems into the grid. This in-depth knowledge and experience includes learning related to: (1) the definition of technical requirements depending on the use case, (2) the definition of controls functionality, and (3) the actual application and use of energy storage while connected to the grid. Experience across many projects in various environments serving different applications also helps SCE better understand potential risk and identify mitigation measures (i.e., related to safety, security, climate, third-party maintenance, reliability, and remoteness).

The DESI O&M forecast supports the planning and operation phases of the pilots including: (1) the extraction of lessons learned during the first two years of operation during Measurement & Verification (M&V), (2) normal O&M activities during the post-M&V period for the remaining useful life of the system, and (3) activities related to operationalizing lessons learned through organizational change management, technology transfer, and deployment readiness (i.e., development of processes, standards, specifications to support wide-scale deployment of energy storage as standard utility equipment). O&M expense also includes a small amount for DESI program management (to support the overall program) and pre-capital planning (which includes costs associated with development and site selection that does not result in a capital project, i.e., use case definition, sizing, mapping, property rights checks, and environmental surveys). The O&M expense period covers work related to learning objectives and maintenance outside of the standard warranty.[274] These costs include estimates for retrofit, repair, extended warranty, availability guarantee, post-warranty maintenance, and interconnection maintenance fees.[275] The majority of the O&M expense is associated with operations and is dependent on the number of pilots in operation.

As discussed, in IV.A.2 above, the Tesla Battery Systems will continue to serve to provide for RA eligible, utility-owned, turnkey, IFOM energy storage projects at SCE's substations or on utility-owned or utility-operated sites south of Path 26, consistent with Resolution E-4791.[276]

---

274 The typical standard warranty is two years.

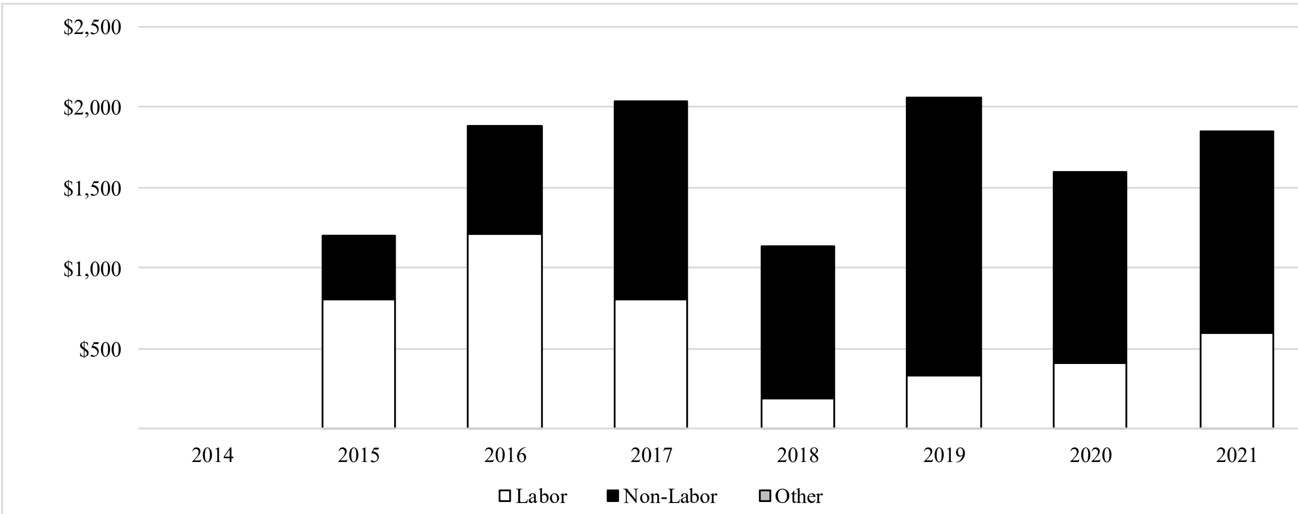
275 Interconnection maintenance fees are standard fees billed by the Distribution Owner (SCE) to the applicant (DESI projects) to maintain interconnection equipment.

276 Resolution E-4791, Finding 42, p. 20.

c) Scope and Forecast Analysis

Figure IV-40 below summarizes the 2014–2018 recorded and 2019–2021 forecast O&M expenditures for the Energy Storage BPE.

Figure IV-40
Energy Storage[277]
Recorded and Adjusted O&M 2014-2018/Forecast 2019-2021
(Constant 2018 $000)[278]



	Recorded					Forecast		
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Labor		$806	$1,216	$800	$193	$330	$408	$592
Non-Labor		$400	$665	$584	$527	$630	$762	$821
Other					$3			
Energy Storage Initiative Total		**$1,205**	**$1,881**	**$1,384**	**$723**	**$960**	**$1,170**	**$1,413**
Labor				$7	$1			
Non-Labor				$638	$399	$1,100	$431	$431
Other								
Mira Loma Tesla A and B Total				**$645**	**$400**	**$1,100**	**$431**	**$431**
Labor		$806	$1,216	$807	$194	$330	$408	$592
Non-Labor		$400	$665	$1,222	$926	$1,730	$1,192	$1,252
Other					$3			
Overall Energy Storage Total		**$1,205**	**$1,881**	**$2,029**	**$1,123**	**$2,060**	**$1,601**	**$1,844**

Basis of Forecast: Itemized Forecast

(1) Historical Variance Analysis

(a) Labor

From 2015 to 2016, labor costs for the Energy Storage Initiative increased by $410,000. Of this amount, SCE incurred $212,000 during the planning process for the

[277] Please refer to: WP SCE-02, Vol. 4, Pt. 1, Ch. IV – Book B - pp. 62 - 68 – O&M details for Energy Storage Initiative.

Aliso Canyon Energy Storage (ACES) RFP.[279] The ACES RFP resulted in the two Tesla Battery projects, but as part of the effort to identify potential project sites, SCE incurred $212,000 in labor related to unsuccessful site development. SCE originally charged the $212,000 to DESI O&M expense, but, in 2018, SCE recorded the charges in the ACES Balancing Account as required by D.18-06-009, the Decision granting cost recovery of ACES costs.[280] Therefore, 2016 labor costs related to DESI were $1.0 million, and the year over year increase was actually $198,000, which was related to ramping up planning efforts for additional DESI pilots. Labor resources dedicated to the DESI program charge to either O&M expense or capital depending on activity prioritization and where the projects are in the project lifecycle (i.e., early project initiation and operations are charged to O&M, and project planning and execution are charged to capital).

From 2016 to 2017, labor costs decreased by $204,000 (after removal of 2016 ACES charges). The decrease resulted from two projects (DESI 2 and Mercury 4) starting to incur capital costs which shifted labor costs from pre-capital planning to capital project execution.[281]

From 2017 to 2018, labor costs decreased by $607,000 because the team effort was capitalized as part of the construction of DESI 2 and Mercury 4, which were operational at the end of 2018. Three other projects entered the project deployment phase (Mercury 1, Mercury 2, and Gemini 1) with labor costs capitalized.

(b) Non-Labor

(i) Energy Storage Initiative

From 2015 to 2016, non-labor costs increased by $265,000 to $665,000. Of this amount, SCE incurred $339,000 in planning for the ACES RFP.[282] So, adjusted

---

278 As discussed in the Compliance Requirements above, SCE was authorized to establish the ACESBA to record the Tesla Projects' actual revenue requirements. The ACESBA was used to record the costs prior to 2021 when the remaining cost recovery would be transitioned to SCE's General Rate Case base rates in SCE's 2021 General Rate Case.

279 *See* discussion related to ACES RFP in Section IV.A.2.

280 D.18-06-009, pp. 42 – Conclusion of Law #2.

281 Pre-capital planning includes activities associated with project initiation, sizing, site selection, and site due diligence associated with projects that do not go forward or for costs not associated with a particular capital project.

282 *See* discussion related to ACES RFP in Section IV.A.2.

2016 non-labor costs related solely to DESI were $326,000, which was a $74,000 decrease from the $400,000 incurred for non-labor costs in 2015. Since resources shifted to ACES planning and execution, fewer resources applied to DESI planning.

From 2016 to 2017, non-labor costs increased by $258,000 (after removal of $339,000 ACES charges in 2016, which resulted in 2016 non-labor costs of $326,000 solely related to DESI). The increase was due to the addition of contract labor for project planning and to assist with additional projects initiating the interconnection application process.[283]

From 2017 to 2018, non-labor costs remained flat.

(ii) Mira Loma Tesla Energy Storage

From 2017 to 2018, non-labor costs decreased by $245,000 to $400,000 resulting from timing of invoices coupled with both sites A and B's failure to meet the contractual threshold established to receive the performance guarantee for 2017, which resulted in an adjustment down of the variable maintenance fee.

(2) Forecast

SCE projects a total O&M cost of $3.9 million for 2019-2021, as summarized in Figure IV-40 and detailed in the DESI Pilot Program O&M Workpaper. The forecast is based on approved purchase orders, quotes and established pricing with two vendors, recent project costs, and accounting/engineering estimates from subject matter experts on potential repairs or upgrades that may be needed during system operations.[284]

The forecast estimate is driven by fixed program management costs and variable system operational costs depending upon the number of pilots online (see DESI Pilot Program O&M Workpaper). Labor costs include program management, operations and maintenance (including the extraction of lessons learned), pre-capital planning activities, and technology transfer. The non-labor cost functions include program expenses, contract labor supporting maintenance and operations (preventive maintenance is performed per equipment manufacturer recommendations and in some cases

---

[283] The DESI projects adhere to the same interconnection process as third party systems would, *i.e.*, even though the DESI projects are owned by SCE, there is no preferential treatment given and the DESI projects are subject to the same rules and fees under SCE's Wholesale Distribution Access Tariff (WDAT) or Rule 21 Exporting Generator Interconnection Request.

[284] Testimony below provides additional discussion regarding the cost forecast methodology and competitive RFP resulting project costs and estimates.

SCE purchases extended warranty and/or availability guarantee services), extraction of lessons learned, and interconnection maintenance costs.

(a) Labor

DESI O&M labor costs support overall program management (including reporting, communications), operations and maintenance, pre-capital planning (pilot development and site selection), and technology transfer.

In 2019, SCE forecasts DESI O&M labor of $330,000 to support program management, operations and maintenance of three pilots, and pre-capital planning for two pilots.

In 2020, SCE forecasts DESI O&M labor of $408,000 to support program management and operations and maintenance of nine pilots. From 2019 to 2020, labor costs are estimated to increase by $78,000. The increase is due to additional projects moving into the operations phase (addition of six systems in operation in 2020).

In 2021, SCE forecasts DESI O&M labor of $592,000 to support program management and operations and maintenance of 11 pilots. From 2020 to 2021, labor costs are estimated to increase by $184,000. The increase is due to all 11 DESI projects being online and additional labor resources that shift from project execution (capital spend) to technology transfer with a focus on operationalizing lessons learned through organizational change management and deployment readiness (i.e., development of processes, standards, specifications, etc. to support wide-scale deployment of energy storage as standard utility equipment).

(b) Non-Labor

(i) Energy Storage Initiative

DESI O&M non-labor costs support program expenses, contract costs for operations and maintenance (including services for program management, preventive maintenance, repairs, extended warranty, and availability guarantee), and interconnection maintenance fees (see DESI Pilot Program O&M Workpaper).

In 2019, SCE forecasts DESI O&M non-labor of $630,000 to support program costs, contracts for program management and system maintenance (three systems in operations), and interconnection maintenance fees (for one system).

In 2020, SCE forecasts DESI O&M non-labor of $762,000 to support program costs, contracts for program management and system maintenance (nine systems in operations), and interconnection maintenance fees (for three systems). From 2019 to 2020, SCE estimates non-labor costs to increase by $132,000. The increase is due to additional projects moving into the operations phase (addition of six systems in operation in 2020).

In 2021, SCE forecasts DESI O&M non-labor of $821,000 to support program costs, contracts for program management and system maintenance (11 systems in operations), and interconnection maintenance fees (for five systems). From 2020 to 2021, SCE estimates non-labor costs to increase by $59,000. The increase is due to all 11 DESI projects being online with the related costs for operations and maintenance and interconnection maintenance fees.

(ii) Mira Loma Tesla Energy Storage

From 2018 to 2019, non-labor costs are forecasted to increase by $700,000 to $1.1 million due to billing cycle timing whereby the 2018 fixed maintenance fees were recorded and paid in 2019. In addition, we expect a true-up of unbilled interconnection fees (2016-2018) of $335,000 from T&D to be processed and charged to the Tesla Energy Storage activity in 2019. As discussed above, O&M expenses are subject to a performance guarantee adjustment to the variable fee upon failure to meet performance thresholds.

The 2021 O&M forecast of $431,000 for the battery systems is comprised of non-labor fixed and variable costs paid to Tesla to provide necessary supervision, labor, materials, tools, and equipment to maintain a fully operational energy storage system. This forecast was based on the 2018 last year recorded fixed and variable contractual maintenance fees which included performance adjusters, escalated to 2021. Further details can be seen in the workpaper.[285]

d) Basis for O&M Cost Forecast

(1) Energy Storage Initiative

The O&M costs are made up of fixed program management costs and variable system operational costs based on the number of pilots online. Further details can be seen in the DESI Pilot Program O&M Workpaper.[286] The cost per project during operations also depends on interconnection maintenance fees (fee is 0.38% per month of project specific interconnection equipment

[285] Please refer to workpaper: WP SCE-02, Vol. 4, Pt. 1, Ch. IV – Book B - pp. 71 - 72 – Tesla Energy Storage O&M Workpaper.

[286] Please refer to workpaper: WP SCE-02, Vol. 4, Pt. 1, Ch. IV – Book B - pp. 69 - 70 - DESI Pilot Program O&M Workpaper.

costs as required in the Wholesale Distribution Access Tariff), vendor quotes for specific projects (based on size and operational year), and the selection of extended warranty or maintenance options (depending on the use case).

SCE assumes that each DESI pilot will have a two year M&V period where the system is operated for the purposes of capturing lessons learned while serving its targeted use case, which includes, for example, distribution reliability or facilitation of preferred resources. After the M&V period, SCE will operate the system through its remaining useful life to continue to serve its reliability and/or market function.

For vendor costs, SCE engaged in a competitive RFP process at the end of 2017 with multiple battery integration vendors responding to the RFP. Based on pricing and technical information provided in vendor RFP responses, SCE conducted a qualitative and quantitative analysis of vendor capabilities. SCE then selected two vendors that demonstrated recent experience in deploying battery energy storage systems and capabilities meeting SCE's requirements, under best value contracted pricing. Each vendor executed two contracts, (1) an Engineering, Procurement, Construction, and Maintenance (EPCM) Agreement to facilitate the delivery of a turnkey energy storage system, and (2) a Master Services Agreement (MSA) for retrofits and post-warranty repairs. The Agreements incorporate lessons learned from the earlier contracts used to procure DESI 1, DESI 2 and Mercury 4. SCE negotiated these service agreements in parallel with supply agreements to maintain SCE's leverage to get the best pricing possible before committing to a given vendor. The Agreements also establish pricing for systems procured in 2018, 2019, and 2020. SCE negotiated extended warranty and maintenance pricing for the first seven operating years of the systems. SCE did this up-front when it had more leverage to negotiate lower cost options.

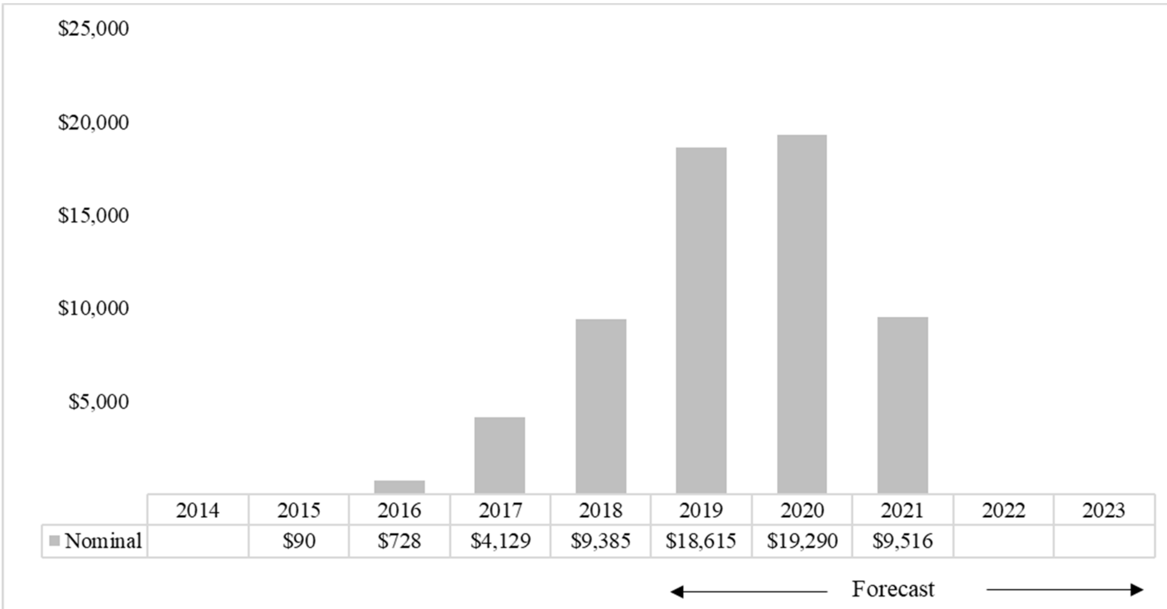
(2) Mira Loma Tesla Energy Storage

The O&M forecast for the Tesla Energy Storage is made up of contractual fixed fees (5 year contract with Tesla), to perform standard annual maintenance of the systems as discussed above, as well as variable fees which are driven by established performance (generation) thresholds. Lastly, the O&M also includes transmission interconnection fees, which are fixed payments paid to T&D for interconnection services to the grid.

D. Capital Expenditures for Implementing Energy Storage

The capital request shown below in Figure IV-41 supports the capital upgrades and project close out of three operational systems and eight additional systems to be deployed through 2021.

Figure IV-41
2014 – 2018 Recorded/2019-2023 Forecast Capital Expenditures for Distributed Energy Storage Integration (DESI) Pilot Program[287]
CWBS Element CET-PD-OT-ES
(Total Company - Nominal $000)



A breakdown of the capital expenditure forecast for the DESI Pilots by project is shown below in Table IV-24.

[287] Please refer to WP SCE-02, Vol. 2, Pt. 1, Ch. IV – Book B - pp. 73 – 74 – Capital Details by WBS for Distributed Energy Storage Integration (DESI) Pilot Program.

Table IV-24
DESI Pilot Breakdown by Project
2019 – 2023 Forecast
(Total Company – Nominal $000)

		Forecast				
DESI Project	**Operational Date**	**2019**	**2020**	**2021**	**2022**	**2023**
DESI 1	2015	$295				
DESI 2	2018	$74				
Mercury 4	2018	$25				
Mercury 2	2020	$2,932	$3,602			
Mercury 1	2020	$3,560	$3,081			
Gemini 1	2020	$2,907	$2,020			
Mercury 3	2020	$3,626	$2,204			
Apollo 2	2020	$4,432	$1,678			
Apollo 1	2020	$764	$4,970			
Gemini 2	2021		$867	$4,758		
Gemini 3	2021		$867	$4,758		
Total (Energy Storage)		$18,615	$19,290	$9,516	$0	$0

1. <u>Energy Storage Pilots</u>

a) <u>Program Description</u>

In the 2018 GRC, DESI proposed $69.2 million in capital spend to build 12 pilots in 2016-2020 (this included the build of DESI 2 & DESI 3, approved in the 2015 GRC, and 10 additional pilots) to bring the DESI program to a total of 13 pilots (including DESI 1). The current forecast for the DESI program is $61.5 million in capital spend on 11 pilots. The change represents a reduction of $7.7 million in capital spend and two fewer pilots; SCE still intends to extract the originally planned lessons learned and value from the 11 pilots. The spend per project is higher than estimated in the 2018 GRC due to larger system sizes to properly address each use case; however, the overall program spend is lower with the same planned lessons learned.

In the 2019-2023 timeframe, SCE forecasts some capital expenditure (through 2021) to complete and properly upgrade the DESI pilots initiated based on the approved 2018 GRC request.

The 2015 GRC Decision approved three DESI pilots to validate, in SCE's production operating environment, the ability of a Battery Energy Storage System (BESS) to provide feeder load relief,[288] give voltage support, and smooth the delivery of energy from renewable distributed generation to the grid. DESI was also intended to establish the aggregation and control of multiple systems and the ability of energy storage systems to integrate to the grid safely and reliably. Specifically, the originally proposed DESI pilot systems were focused on *how to best integrate energy storage onto the grid*.

The 2018 GRC Decision approved expanding the DESI pilot program beyond three pilots to continue to support market transformation and help to safely and reliably integrate energy storage on the grid. The original pilots focused on *how to integrate energy storage onto the grid*. The ten[289] expansion pilots focus on *extracting value from energy storage projects* and translating lessons learned into design standards, processes, and procedures. This will prepare SCE to integrate energy storage as an established planning and operational tool.

In the 2021 GRC cycle, SCE will continue deploying expansion pilots as approved in the 2018 GRC filing but does not propose any additional pilots as part of DESI. In fact, SCE's initial DESI proposal was for a total of 13 pilots (3 original and 10 expansion). SCE's current plan will meet the learning objectives of DESI through 11 pilots (3 original and 8 expansion).

(1) Original DESI Pilots – DESI 1 & 2 (2015 GRC)

SCE's first DESI pilot (DESI 1), a 2.4 MW / 3.9 MWh lithium-ion battery system on the Scarlet 12 kV circuit, became operational in 2015. SCE continues to operate this system to support the circuit during periods of high demand.[290] SCE forecasts capital spend of $295,000 for DESI 1 in 2019 for cybersecurity upgrades.

DESI 2, a 1.4 MW / 3.7 MWh lithium-ion battery system on the Titanium 12 kV circuit, became operational in 2018. DESI 2 incorporated lessons learned from DESI 1. DESI 2 currently serves distribution operations and is completing steps to be available for CAISO market participation (it will be one of the first multi-use systems). Accordingly, it will serve as a valuable

[288] A battery performing feeder load relief is configured to discharge proportionally to prevent the total load on the feeder from exceeding a threshold. For example, if a circuit has a planned load limit (PLL) of 550 amps, the battery will discharge at a dynamic power level to prevent the load from exceeding 550 amps. The battery will later recharge when there is less load on the feeder.

[289] Though ten pilots were approved in the 2018 GRC, SCE will move forward with eight while achieving the same learning objectives.

[290] There are no capital expenditures for DESI 1, other than for cybersecurity upgrades, in the 2021 GRC, as it became used and useful in 2015 and was added to rate base in the 2018 GRC.

platform to develop processes and procedures required to safely and efficiently manage multi-use systems. SCE forecasts capital spend of $74,000 for DESI 2 in 2019 for continued efforts to connect to the CAISO market, permits, and project closeout.

(2) Expansion of DESI Pilots (approved in 2018 GRC)

SCE expanded the DESI Pilot Program to support various capabilities, including but not limited to: enhancing distribution reliability, enhancing transmission substation reliability, integrating DERs, demonstrating multi-use (serving both a grid reliability function and selling energy into the CAISO market), fostering microgrids, and spurring electrification of transportation and buildings. Systems also vary in size based on the power and duration needs of the specific application, and whether the BESS will participate in the wholesale market. SCE will seek diversity of storage across climate zones and rural/urban mix and load patterns to evaluate operating performance. Current capital pilot deployments utilize commercially mature lithium-ion batteries.

SCE continues to assess the benefits of energy storage in particular applications. Identification and quantification of benefits for BESS are being tracked and validated, and DESI pilot results are already contributing to benefit-cost discussions related to the viability of energy storage as an alternative project in multiple licensing project proceedings.[291] Benefits, such as the deferral value of traditional capital upgrades and market participation, may be quantifiable, but need to be validated and accounted for in energy storage cost-benefit analyses. The DESI Pilot Program Expansion also aims to help us (on behalf of our customers) understand whether energy storage can provide benefits such as equipment life extension, voltage optimization, DER integration enhancement, phase balancing, reactive power compensation, enhancing power quality, and/or participating in N-1 contingency[292] scenarios by exercising the energy storage systems during the M&V period.

(a) Distribution Reliability – Mercury 1 & 2

Distribution Reliability pilots are using BESS as a tool to assess how energy storage can help mitigate distribution substation planning criteria violations. In the 2018 GRC, SCE proposed three pilots to learn how BESS could contribute to distribution reliability. However, SCE expects to achieve its objectives in this area through the deployment of two pilots.

---

[291] As part of California Environmental Quality Act (CEQA), SCE has considered energy storage as a potential alternative to traditional projects, such as new substations. DESI lessons learned have informed the cost estimation and evaluation of the alternative projects.

[292] An N-1 condition is an outage or failure of a single line, transformer, or major component at a distribution substation.

SCE is building two co-located, but electrically independent projects in this category, each system connects to circuits fed by the Narrows Substation in the City of Pico Rivera. These systems, which will be operational in 2020, defer traditional capital upgrades related to a Subtransmission N-1 contingency to account for an outage on one of the two lines feeding the substation. Building two systems[293] allows SCE to determine how projects may be phased to cost-effectively add capability as needed and how Grid Operations can optimize the use of multiple assets to manage loading limits and other operational constraints. These systems, like DESI 2, will have multi-use capability. The systems are currently in the engineering phase and have resulted in additional learning associated with the implementation of design changes (i.e., ventilation, fire suppression) needed to comply with new California Fire Code requirements for Stationary Storage Battery Systems.[294]

- Mercury 1 is a 3.0 MW / 9.00 MWh system on the Yorktown 12 kV circuit with a target operational date of 2020.
- Mercury 2 is a 3.5 MW / 8.75 MWh system on the Cadillac 12 kV circuit with a target operational date of 2020.

SCE notes that in 2018, the Commission established Distribution Resources Plan (DRP) Distribution Investment Deferral Framework (DIDF), which provides opportunities for third-party owned DERs to defer or avoid traditional investments in SCE's distribution system. Because these Distribution Reliability pilots described were included and approved as part of SCE's 2018 GRC, are already in execution and will provide learning benefits for SCE to better integrate third party DERs in the future, SCE will not include them in the DIDF.

(b) <u>Facilitation of Preferred Resources – Mercury 3 & 4 and Gemini 1</u>

SCE is piloting energy storage systems to integrate renewable energy and has targeted areas with existing or imminent high penetration of DERs. As the penetration of DERs (such as residential PV arrays) increases on the distribution grid, system upgrades will be required to mitigate the following potential impacts: (1) circuit overload; (2) voltage fluctuation; (3) reverse power flow; (4) system protection; and (5) system reconfiguration.

[293] These projects will provide the lessons learned associated with managing multiple systems that were expected from DESI 3, which was cancelled.

[294] California Fire Code Section 608 defines new requirements and was adopted in Q3 2018. These are the first systems SCE will deploy since the new requirements became effective.

Energy storage can mitigate some of these issues by: (1) *charging* when the generation on the circuit exceeds the load or the circuit capacity; and (2) *discharging* when the load is greater than the generation, or when circuit capacity is available. Energy storage can potentially minimize large generation output variation by smoothing the generation output -- discharging when generation decreases and charging when generation increases. This minimizes voltage fluctuation. In addition, the ability of a BESS to act as a generator or a load can improve a distribution circuit's capacity to support the power needs of customers.

Two systems will be installed in the high desert area where PV penetration is particularly high on certain circuits. Deployment in this region also provides lessons learned related to operations in hot, arid conditions. These projects are helping SCE to develop tools, processes, and procedures for (1) identifying and scoping opportunities to utilize energy storage to enhance PV dependability and increase hosting capacity and (2) managing reverse power flow and providing voltage support with energy storage systems. Executing two projects ensures new processes are sustainable and repeatable and provides an opportunity to compare and contrast product performance and service levels provided by multiple vendors.

Mercury 4 is a 2.8 MW / 5.6 MWh system on the Pronghorn 12kV circuit that became operational in 2018. The BESS will address potential issues caused by over 11.5 MW of connected PV (from both NEM and Rule 21 customers) that can create as much as 8 MW of reverse power flow during the day on this circuit in Lancaster, CA. SCE forecasts capital spend of $25,000 for Mercury 4 in 2019 for project closeout.

Mercury 3 is a 2.5 MW / 4.5 MWh system on the Stealth 12 kV circuit with a target operational date in 2020. The Stealth circuit in Palmdale has approximately 4.3 MW of PV connected causing a high peak load in the early evening and reverse power flow during the day.

Gemini 1 will be installed to support SCE's existing Poole Hydro Plant in the Bishop/Mammoth Region of SCE's service territory. Deployment in this region also provides lessons learned related to cold weather conditions. Gemini 1 is a 3.5 MW / 3.5 MWh system on the Strosneider 16 kV circuit with a target operational date of 2020. This region can be islanded from the rest of the grid to maintain service if the 115 kV line feeding the area is disconnected for any reason. The duration for which the region can be islanded is limited by reservoir levels at the Poole Hydro plant. The hydro plant also has limited ramp rates, which can be challenging to manage in conjunction with fluctuations in area load and customer-owned PV generation. Implementation of the BESS allows SCE to better manage reservoir levels, hydro plant ramping, area load fluctuations, and fluctuations in customer-owned PV generation, thereby improving reliability and resiliency, especially during islanded conditions.

(c) Other Applications

SCE continues to seek opportunities to pilot storage where unique storage characteristics solve planning and operational grid problems. In SCE's 2018 GRC filing, the stated criteria for these types of projects would include: (1) leveraging the fast response of storage systems; (2) increasing grid resiliency for critical and/or remote loads; (3) supporting microgrid developments that provide resources that benefit a region on the grid; and (4) supporting projects that enable electrification and greenhouse gas reduction objectives. SCE has identified project opportunities that address these issues, and often a single project may be able to address multiple issues. The following summarizes current and expected work in this area, in two categories.

(i) Grid Resiliency, Reliability and Electrification Support through Flexible and Accelerated Deployment Capabilities – Apollo 2 and Gemini 2

SCE has planned pilots with systems that can be moved to support reliability, resiliency and electrification, depending on case by case parameters. With the flexibility of relocating equipment, a single investment may support all three areas over time.

Apollo 2 is a transportable 3 MW / 6 MWh system on a circuit out of the Cal City Substation with a target operational date in 2020. A transportable energy storage system is one that has design features and a manufacturer-supported warranty that allow it to be disconnected, moved, and reconnected at a new location, several times over its useful life, with minimal support from the manufacturer. For example, a transportable system requires minimal site improvement, uses either skid or trailer-based equipment, and can be moved from site to site without having to remove battery modules. By comparison, many manufacturers do not warrant a traditional, fixed energy storage system if it is relocated, and such systems usually require significant disassembly, including removal of all battery modules, before being moved. The first deployment of this transportable system will be to address unanticipated, rapid load growth in California City. Once SCE's permanent grid improvements are in place to address the load growth, the transportable BESS will be relocated to address another need. At this time, the second deployment is to be determined, but SCE expects to also utilize the same equipment to facilitate electrification of medium- and/or heavy-duty transportation fleets more rapidly than would otherwise be possible, given how many years it can take to add the tens of MW of capacity required to support associated charging loads. The cycle will be repeated as needed in order to extract as much value from the system as possible. Key lessons learned surround decommissioning and relocation of system elements between deployments.

Gemini 2 is a mobile kW-class energy storage system(s) with a target operational date in 2021. A mobile energy storage system is one that has design features and a manufacturer-supported warranty that allow it to be disconnected, moved, and reconnected at a new location, tens or even hundreds of times over its useful life, with no direct support from the manufacturer. For example, a mobile system requires little to no site improvement, likely uses trailer-based equipment, and can be moved from site to site without having to disconnect individual pieces of equipment or remove battery modules. The mobile system would be used to rapidly address short-duration issues typically caused by unplanned outages, leveraging lessons learned from SCE's EPIC project Versatile Plug-In Auxiliary Power Systems (VAPS), where SCE has demonstrated the feasibility of using lithium-ion battery-based power systems to power off-grid (e.g. job site) electrical loads. The mobile concept's feasibility analysis includes review of both: (1) reliability-driven applications, where energy storage can reduce customer minutes of interruption during typical repair and (2) maintenance work, or resilience-driven applications, where energy storage can reduce the likelihood customers lose access to electric service during major events.

(ii) <u>Resilience Partnerships through Microgrids – Apollo 1 and Gemini 3</u>

Large customers and multiple customers in proximity to each other may more effectively meet their resiliency objectives if they could partner with the utility to implement microgrids, where distribution grid assets and DERs are operated together as a single microgrid. The distribution grid assets would support normal grid operations when the microgrid is connected to the grid, and then would be used to manage the microgrid when islanded. Passage of Senate Bill (SB) 1339[295] and steadily growing interest in microgrids from SCE's Commercial and Industrial (C&I) customers indicate broad support for this concept. Two pilot projects will include:

---

[295] Directed the Commission to develop a standardized interconnection process, as well as appropriate rates and tariffs, for microgrids by December 1, 2020.

Apollo 1 is a pilot with a target operational date of 2020. Sizing and specific location are still being identified. The system will support a microgrid project at a military base to ensure continued operation of critical military loads during an outage event, support voluntary islanding[296] to serve national defense interests, and enable SCE to develop technical requirements, processes and procedures for supporting implementation of energy storage supporting microgrids that are primarily driven by a single large customer.

Gemini 3 is a pilot with a target operational date of 2021. Sizing and specific location are still being identified. This pilot will support a microgrid project connected to multiple critical loads. Examples of these loads could be, but are not limited to, law enforcement agencies and fire departments. The microgrid will help ensure continued operation during an outage event through voluntary islanding. Continued operations of key agencies, such as law enforcement agencies and fire departments, will improve public safety during outage events. The project will support SCE in developing technical requirements, processes and procedures for supporting implementation of energy storage supporting microgrids that are driven by multiple customer needs.

b) Need for Capital Program

The Energy Storage Decision set a goal to transform the energy storage market to overcome the barriers that are hindering broader adoption of emerging technologies.[297] The Energy Storage Decision establishes three guiding principles for the Commission's energy storage procurement policy, which in turn have become guiding principles for the DESI pilots:

1. Optimize the grid, including peak reduction, contribution to reliability needs, or deferment of transmission and distribution upgrade investments;
2. Integrate renewable energy; and
3. Reduce greenhouse gas emissions by year 2050 to 80 percent below 1990 levels.[298]

The Energy Storage Decision also established an energy storage mandate for SCE of 580 MW. The systems must be procured by 2020 and operational by 2024. The MWs installed under the DESI program will count toward the mandate and, more importantly, will support the lessons

---

[296] Islanding refers to the ability for the microgrid to operate independently of the distribution grid.

[297] D.13-10-040, p. 7.

[298] D.13-10-040. at pp. 9-10.

learned needed to transform the energy storage market, advancing storage technology for use as a grid tool by identifying when energy storage can benefit the grid and establishing protocols for how to deploy and operate.

The DESI pilots have and will continue to provide needed data and lessons learned to support the Commission's energy storage policy goals, while helping ensure that integrating energy storage does not diminish safety and reliability for our customers or workers. As SCE prepares energy storage for deployment readiness, we are documenting processes and requirements that are formalized into SCE operating bulletins and standards, respectively. For instance, SCE took various requirements developed in support of DESI and is working to refine these into company adopted standards that can be applied to future third party and/or utility owned storage projects. Examples include technical requirements for the battery, grounding of the battery system in the transmission right of way property, and signage.

Lessons learned have also informed SCE efforts in supporting applications before the Commission for projects requiring a Commission-issued permit including Circle City Substation and Mira Loma-Jefferson 66kV Subtransmission Line Project,[299] and Alberhill System Project.[300] More specifically, SCE has leveraged DESI-developed tools and methods to evaluate energy storage as a solution for specific applications, calculate the system size to serve a specific need or use case, and identify interconnection requirements.

It has been and will continue to be critical for SCE to own and operate the DESI pilots in order to gain the in-depth knowledge and experience needed to capture and apply lessons learned. With each project, SCE revises and refines requirements, procurement, construction, and operations. Experience across many projects in various environments serving different applications also helps SCE better understand potential risk and identify mitigation measures. This experience means SCE will be able to more successfully utilize energy storage to support the grid and minimize potential risk when moving into broad deployment.

---

[299] A.15-12-007.

[300] A.09-09-022.

c) **Basis for Capital Expenditure Forecast**

SCE projects a total capital cost of $47.4 million from 2019-2023, as summarized in Table IV-24 and the DESI Pilot Program Capital Workpaper[301] (also see Section IV.C.1.d)(1).1.a) for explanation of the change in number of pilots from the 2018 GRC proposal). The forecast is based on quotes and established pricing with two vendors, recent project costs, and accounting/engineering estimates from subject matter experts on interconnection and distribution upgrades and designing, constructing, commissioning, and testing the BESS.

The projects typically follow a two-year deployment timeframe. In year one, SCE initiates planning, identifies the use case, and sizes and procures the system. SCE also initiates the interconnection application, which is a long lead item. In year two, SCE completes engineering, procurement, construction, commissioning, and testing activities.

In 2019, SCE intends to make cybersecurity upgrades for DESI 1, close out capital activities for two projects (DESI 2, Mercury 4), complete engineering and civil construction of five projects (Mercury 1, Mercury 2, Mercury 3, Gemini 1, and Apollo 2), and perform planning activities for Apollo 1. The 2019 spend is estimated at $18.6 million.

In 2020, SCE will bring six projects online (Mercury 1, Mercury 2, Mercury 3, Gemini 1, Apollo 1, and Apollo 2) and continue planning for the remaining two projects (Gemini 2 and Gemini 3). The 2020 spend is estimated at $19.3 million.

In 2021, SCE will complete Gemini 2 and Gemini 3 with spend of $9.5 million.

After 2021, the DESI pilots will all be operational. SCE does not have any capital forecast estimated in 2022 and 2023.

[301] Please refer to workpaper: WP SCE-02, Vol. 4, Pt. 1, Ch IV. – Book B - pp. 75 - 89 - DESI Pilot Program Capital Workpaper.

Appendix A

Grid Modernization Plan

Appendix A

Table of Contents

Appendix A

Table Of Contents (Continued)

Section	Page	Witness

Grid Modernization Plan[1]

I.

OVERVIEW

A. 10-Year Vision for Grid Modernization

1. Introduction

As Southern California Edison Company (SCE) moves to a clean energy future increasingly powered by renewables and distributed energy resources (DERs)[2] — including distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies — the systems needed to make the electric grid operate safely and effectively are becoming increasingly complex. Renewables and DERs are redefining the "grid edge"[3] since they can be interconnected to the distribution grid either behind or in front of the customer's meter. Meanwhile, customer demands for reliable power continue to increase.

These changes demand that SCE create the grid of the future — one that supports high levels of carbon-free resources and integrates new technologies and services, while being safe, reliable and resilient. The modernized grid is a foundational element of SCE's 10-year Grid Modernization vision: Over the long term, SCE plans to make significant investments to create a safer, cleaner, more reliable, more resilient, and more efficient grid that integrates new customer technologies and provides opportunities for customers to realize greater value from their investments.

SCE's long-term vision for modernizing its distribution business includes:

1. **Modernized electric system planning and grid operations** that support increasingly complex energy transactions on the electric system;

---

[1] This Appendix presents SCE's Grid Modernization Plan as required by D.18-03-023, Ordering Paragraph (OP) 4, pp. 34-35, for the Order Instituting Rulemaking (OIR) Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans (DRP) pursuant to Public Utilities Code Section 769. OP 4 orders that the GMP be a Chapter in their GRC filings. This Appendix is part of the volume discussing Grid Modernization and will be part of the Test Year 2021 GRC evidentiary record and provides evidentiary support for SCE's request; therefore, it meets the requirements of OP 4.

[2] PUC §769. (a) For purposes of the Grid Modernization Plan, "Distributed Energy Resources" means distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies.

[3] The grid edge refers to the area of the distribution grid between the customer meter and the distribution substation.

2. **Customers empowered to choose to be partners** in making the grid more reliable, efficient and clean; and

3. **Distribution markets** enabled to maximize the value of DERs and efficiently meet SCE's affordability, reliability, and decarbonization goals.

This document is SCE's Grid Modernization Plan (GMP) to implement technologies that will enable SCE to integrate and optimize DERs while maintaining and improving safety and reliability and providing other customer benefits. The GMP illustrates the Grid Modernization investments necessary over a ten-year period and is mindful of the potential impacts of customer and market behavior on SCE's distribution system. The GMP transcends merely integrating DERs—it prepares SCE for the transformation of the entire distribution business, to ensure maximum value for customers and to achieve ambitious environmental goals.

2. Grid Modernization

For most of SCE's 130-year history, the traditional one-way power flow model of the distribution grid (where power flows from large central generation stations over transmission networks and radially to distribution customer loads) has been the norm. Engineering, planning, construction and operations of the distribution system have been centered on principles of one-way power flow, which allowed simplified assumptions about the distribution system. Over the last 10 years, as California implemented public policies to further reduce the environmental impacts of energy consumption, there has been a dramatic shift to renewable resources and decentralized generation, rapid growth in customer adoption of DERs, and increasing bi-directional energy flows from DERs connected either behind or in front of the customer meter. As a result, the traditional one-way power flow model of the distribution system has been disrupted, and existing planning and operating tools do not provide the visibility and operational flexibility necessary to address this new operational complexity.

As power transactions have increased on the distribution system, so has the complexity for SCE's system operators in managing unpredictable bi-directional power flows,[4] masked loads,[5] and reverse power flows.[6] Looking forward, using the 2017 Integrated Energy Policy Report (IEPR) DER

4 Bi-directional power flows can affect voltage control and protection devices.

5 Masked load is when only the net load of generation and consumption is visible, not the actual load.

6 "Reverse power flow" occurs when generation on a distribution circuit exceeds the amount of load on that circuit and causes power to flow into a distribution substation instead of towards customers as originally designed.

forecasts,[7] many of SCE's distribution feeders will experience reverse power flows due to DERs.[8] Though DERs are not yet creating major reliability issues for the majority of SCE's customers, some wholesale DERs are adversely impacted as SCE's system operators manage the system based on the planning and operating tools currently in place. SCE must transform its planning and operations capabilities to address the increase in DER penetration across the distribution grid.

SCE's GMP includes technologies that will better integrate and optimize DERs, improve safety, reliability, and wildfire resiliency, and provide the foundation for a clean energy future. Table 1 summarizes SCE's eight GMP technology categories, each of which are described in detail in this plan.

Table 1
GMP Technology Categories

1. Engineering and Planning Software Tools	5. Grid Management System
2. Automation	6. DER Hosting Capacity Reinforcement
3. Communications	7. Energy Storage
4. Cybersecurity	8. Microgrid Interfaces

Modernizing SCE's grid planning capabilities is the first step to enabling a clean energy future. This includes efforts to: (1) transition from a peak-planning process to an hourly profile-based planning process to help unlock the value of DERs as non-wires alternatives, (2) provide quick and efficient interconnections through a streamlined business process and publish regularly-updated hosting capacity values of the distribution system for transparency, development of automated tools and processes, and more service options, and (3) revise design standards to effectively support new normal operating conditions resulting from DERs (including building and transportation electrification).

Advancing SCE's ability to actively manage the distribution grid will improve operational flexibility. SCE will accomplish this by replacing and automating distribution grid infrastructure (such as switches, sensors, and circuit connections) and introducing the next generation grid management software solutions. This will provide real-time grid data that improves situational awareness and increases operational flexibility to control and configure the grid. As a result, operators will be able to provide faster and more informed responses to grid events and leverage DERs for grid

---

7 Refer to WP SCE-02 Vol.4 Pt. 2, Ch. II – Book A - pp. 14 - 29 – High Distributed Energy Resources Planning Assumptions.

8 Refer to SCE-02 V.4 Pt. 2–Load Growth for more details.

services, which will improve the safety and reliability of the system—despite an ever more complex distribution grid.

SCE needs to upgrade its communication capabilities by expanding its fiber optic network and transitioning to a low-latency, high-speed wireless field area network. SCE will also implement advanced grid management systems that will receive and securely analyze real-time information on customer energy usage, power flows, outages, faults and micro-grid status. The combination of the communications networks and grid management systems will provide vastly expanded amounts of data for managing the grid. To use this data effectively, SCE will integrate the various planning and operations tools to improve planning, operations, outage management, interconnection, and transparency for customers.

By 2028, SCE intends to realize its long-term vision of transforming the grid into a secure, flexible, networked platform that empowers customers with options to be reliability partners, and relies on distribution markets to further the goals of safety, reliability, economic efficiency, and decarbonization. SCE believes a modern utility enables the efficient integration and optimization of DERs, allows customers to participate seamlessly as grid partners, and plans and operates the grid with greater precision through enhanced visibility and control.

3. <u>Customers as Partners</u>

As increasing numbers of Californians adopt DERs, customers are transforming from being consumers of electricity to also supplying it to the grid. As stated earlier, customer adoption of DERs is projected to continue growing rapidly.

As SCE implements its GMP, SCE envisions customers empowered as partners in delivering clean and reliable energy. This will be accomplished by improving customer tools and continuing to support DER adoption. SCE will:

- **Provide more appealing programs and services** that will provide customers with more clean energy choices, enable them to participate in wholesale markets, and contribute to system reliability
- **Enable two-way power flows** and advanced coordination of energy sources that allow customers to seamlessly participate as dynamic partners to provide various grid services to the local system or greater system at times when it is needed

- **Develop and foster partnerships** with DER providers and aggregators to advance the range and quality of services that customers can depend upon by leveraging those companies' areas of expertise and ability to scale quickly

This vision – enabling millions of customers to maximize the value of DERs and provide services to the grid – cannot happen with today's grid technology. Rather, as discussed earlier, it will require new investments and rely on technologies and tools that provide more accurate and granular information about the grid. SCE will need to communicate to customers and their DERs (providing economic signals, need indications, or actual dispatch instructions) in order for customers to respond and become active participants to support the system as a whole, thereby increasing customer choice in how to gain value from their DERs.

4. <u>DER Optimization</u>

DERs can be an important alternative to building additional power plants, substations, and other grid infrastructure. By delivering energy at the right time and the right location, DERs can potentially avoid substantial utility costs associated with traditional infrastructure. To monetize the value of these DERs, SCE is working to create new market opportunities for DERs to provide services to the local grid – and to be compensated for that value. Within the context of the IDER proceeding, SCE has proposed two distinct DER tariff pilots to incentivize deployment and operation of DERs such that they will defer a traditional infrastructure investment.[9] Ultimately, SCE's grid management system (GMS) will enable economic optimization of DERs by allowing SCE to dispatch them at specific times with the most value to the power system. This will expand DER revenue opportunities.[10] Partnering with customers can increase the benefits customers realize from their DERs while also supporting SCE's goals for clean, reliable, and affordable energy.

This vision – to economically optimize utility expenditures and operation of the grid – is again not possible with today's technologies. The ability to perform complex analysis, to possess real-time awareness of grid conditions, and to seamlessly coordinate the performance of millions of devices – including both grid equipment and customer DERs – requires a modernized grid. These investments present new opportunities to achieve SCE's goals with greater economic efficiency, while also ensuring the value of customers' investments is maximized.

---

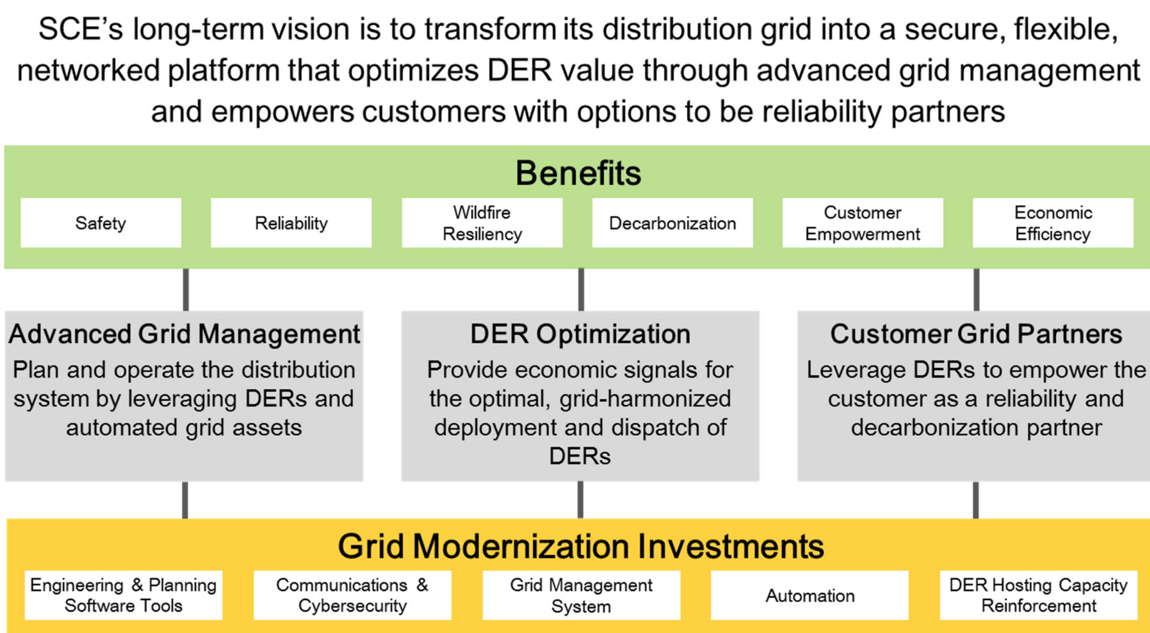
9 *See* Response of Southern California Edison Company (U 338-E) to Administrative Law Judge's Ruling Directing Proposals for Distributed Energy Resources Tariffs, in R.14-10-003, dated February 15, 2019, p. 3.

10 This type of incentive would be an evolution of existing demand side management programs.

5. Summary

A modernized grid is the foundation of SCE's 10-year vison for optimizing DER participation and enabling customers to be reliability partners. Most critically, investments in technologies will ensure the safe and reliable operation of the grid as DER penetration increases dramatically. Beyond the operation of the grid, these technologies will make possible the larger goals of cleaning the power system, enabling customer choice, and maximizing the value of grid and customer resources. SCE's Grid Modernization Vision, and a summary of the benefits and investments are presented in Figure 1.

Figure 1
SCE's 10-year Grid Modernization Vision



B. Changes Necessary to Meet 10-Year DER Growth Forecast

The previous section summarized eight categories of Grid Modernization technologies included in SCE's 10-year Grid Modernization vision. Table 2 identifies the technologies included in SCE's 2021 GRC request for each of the categories and indicates how they align with the technologies in the Grid Modernization Classification Tables.[11]

---

[11] E-4982, Attachment B, pp. 31-37.

Table 2
Mapping of GMP Technologies to Grid Modernization Classification Tables

Technologies in GRC Testimony	Mapping to Grid Modernization Classification Tables
1. Engineering & Planning Software Tools	
Grid Connectivity Model	Grid Connectivity Model
Grid Analytics Application	Grid Analytics Application
Long-term Planning Tool & System Modeling Tool	Short and Long-Term Planning Tools
Grid Interconnection Processing Tool	Interconnection Processing Tool
DRP External Portal	Data Sharing Portal
2. Communications	
Field Area Network	Field Area Network
Distribution System Efficiency Enhancement Project	Field Area Network (legacy system)
Common Substation Platform	Substation Automation and Common Substation Platform
Wide Area Network	Wide Area Network
3. Cybersecurity	Classification Tables identify cybersecurity as a Function of Grid Modernization and Potential System/Integration Challenge, but not as "technology type"
4. Grid Management System	(1) Grid Management System (including ADMS and DERMS), (2) Adaptive Protection System, and (3) Fault Location Isolation System Restoration (software)
5. Automation	
Reliability-driven Distribution Automation	(1) Fault Location Isolation System Restoration (intelligent automated switches), (2) Remote Controlled Switches, (3) Remote Fault Indicators, and (4) Grid Sensors
DER-driven Distribution Automation	Remote Fault Indicators
Small-scale Deployment	(1) Fault Location Isolation System Restoration (intelligent automated switches), and (2) Remote Fault Indicators
Reliability-driven Substation Automation	(1) Substation Automation and Common Substation Platform and (2) Relay Replacement
DER-driven Substation Automation	Substation Automation and Common Substation Platform
Distribution Volt/Var Optimization and Capacitor Automation	Volt/Var Optimization
6. DER Hosting Capacity Reinforcement	
Subtransmission Relay Upgrade Program	DER Hosting Capacity Reinforcement
DER-driven 4 kV Cutovers	
DER-driven Substation Transformer Upgrades	
DER-driven DSP Circuits	
DER-driven Circuit Breaker Upgrades	
DER-driven Distribution Circuit Upgrades	
7. Utility Owned Storage	Utility Owned Storage
8. Microgrid Interfaces (no 2021 GRC request)	Microgrid Interfaces

1. <u>Grid Modernization Upgrade Status</u>

In its 2018 GRC testimony, SCE presented the need, vision, and plan to modernize its system planning processes and tools over the 5-year period 2015-2020. Though there was a significant delay in the 2018 GRC decision,[12] while awaiting this decision, SCE prudently invested in key early-stage implementations of processes and software tools starting in 2016. Consistent with the Commission's subsequent 2018 GRC decision[13] and the 2018 Distribution Resources Plan (DRP) decision,[14] SCE's GMP represents its continued commitment to developing new capabilities to engineer, plan, and operate a modern grid that meets the demands of increasing customer adoption of DERs and California's policy goals while continuing to provide safe, reliable, and resilient electric service.

Each of SCE's Grid Modernization technologies are discussed in detail later in this GMP. The following excerpts provide a brief summary of the status of SCE's completed and current Grid Modernization upgrades.

a) Engineering & Planning Software Tool Deployments

SCE initiated planning, analysis and competitive procurement activities for all five engineering and planning (E&P) software tools in 2015 and 2016, which provided the basis for SCE's 2018 GRC request. These software tools include:

1. **Grid Connectivity Model (GCM):** provides an integrated model of SCE's grid
2. **Grid Analytics Application (GAA)**: provides grid data[15] analytics, visualization, and decision support capabilities required to plan and operate a modern grid
3. **Long-term Planning Tool and System Modeling Tool (LTPT-SMT)**: provides forecasting, power system analysis and work management capabilities that enhance SCE's long term and short term capacity planning and Integration Capacity Analysis (ICA) results
4. **Grid Interconnection Processing Tool (GIPT)**: allows customers and SCE to interconnect generation and load more quickly and efficiently while improving interconnection process transparency

---

[12] A.16-09-001 was filed in 2016 based on a 2018 Test Year; D.19-05-020 was issued on May 24, 2019 after the Test Year period ended.

[13] D.19-05-020, pp. 116-118.

[14] D.18-03-023, Ordering Paragraph 7, p. 36.

[15] Includes historical customer meter data and other field measurements.

5. **DRP External Portal (DRPEP)**: provides the public with detailed, up-to-date information about a circuit's ability to accept DERs, and opportunities for DERs to defer traditional infrastructure investments.[16]

In the fourth quarter of 2016, SCE successfully demonstrated the initial SMT and DRPEP capabilities, which allowed SCE to calculate ICA values for each distribution circuit and publish the results to an external SCE portal—as required by the Commission.[17]

SCE's major accomplishments in 2017 included procuring the LTPT hardware and product vendor licenses and performing development of the GCM to support the initial releases of the other E&P tools.

In 2018, SCE enhanced its ability to perform ICA and publish the monthly results through DRPEP. SCE also enhanced its 10-year system planning and capacity analysis through profile-based forecasting to support the various DRP analysis and reporting requirements related to the Distribution Investment Deferral Framework (DIDF) processes.

b) <u>Communications and Grid Management System</u>

In 2016, SCE built a new lab environment, evaluated several field area network (FAN) vendor products, and completed the common substation platform (CSP) hardware design and prototype testing.

On the grid management side, SCE has defined a comprehensive solution for outage and distribution management system. The GMS is a system of systems consisting of Advanced Distribution Management System (ADMS), DER Management System (DERMS) and advanced application.[18] In 2018, SCE engaged other large utilities[19] to learn from their GMS deployment experience and performed a competitive solicitation for its GMS. SCE also developed and implemented interim control algorithms and DER constraint management functionality until the full DERMS solution is deployed. SCE limited its spending to these activities (instead of the total program proposed in its 2018 GRC) due to the delay in the GRC decision and potential cost recovery concerns.

---

16 This refers to ICA which the values are updated and published monthly, and the annual GNA and DDOR reports.

17 *See* D.18-02-004, OP 2.l through 2.n, p. 85 in R.14-08-013.

18 The advanced applications of the GMS are optimization engine, data historian, device management, adaptive protection system, business rule engine and, short-term forecasting engine.

19 SCE visited Duke Energy, Alabama Power, and Pennsylvania Power & Light (PPL).

c) **<u>Distribution Automation Deployments</u>**

SCE's 2018 GRC proposal included a plan to augment automation capabilities on its worst performing circuits to improve reliability and help integrate higher amounts of DERs. SCE's plan included fully-automating 200 distribution circuits annually. During 2018 until mid-2019, due to the delay in the 2018 GRC decision, SCE moderated the pace of its program. Also, during this time, SCE faced severe labor resource constraints due to the concurrent need for wildfire resiliency engineering, planning and deployment activities. As the wildfire resiliency activity subsides, SCE plans to shift additional labor resources to fully resume the distribution automation deployments.

SCE's automation deployments have focused on (1) upgrading substations with a high risk of relay failures to a modern substation automation design standard (SA-3), and (2) distribution automation deployments on circuits with the worst reliability performance. Table 3 summarizes the substation automation and distribution automation upgrades that have either been completed or initiated to-date.[20]

Table 3
Automation Completed and Initiated To-Date

Category	Upgrades Completed			Planned Completions		
	2016	2017	2018	2019	2020	2021 TY
Substation Automation-3 (Substation Counts)		2	6	6	0	0
Distribution Automation (Cumulative percentage of Distribution Circuits)						
Intelligent Automated Switches	0%	0%	2%	6%	8%	10%
Grid Sensors and RFIs	4%	24%	26%	28%	32%	34%
Upgraded Circuit Ties	0%	0%	0%	0%	2%	4%

2. **<u>Additional Spending Necessary to Achieve GMP Objectives</u>**

Section II. A. provides a ten-year forecast of the capital expenditures necessary to achieve SCE's Grid Modernization vision, including the five-year period (2019-2023) addressed in SCE's 2021 GRC testimony and the subsequent five years (2024-2028). Forecasting the last five years of this 10-year period is based on longer-term projections about the rate of DER adoption, the evolution of wholesale energy markets, system reliability, and other factors that could influence SCE's Grid Modernization needs. SCE therefore has greater confidence in the five-year GRC forecast than the

---

[20] Advanced switches could be either an intelligent automated switch with fault interrupting capability or a remote-controlled switch with telemetry installed at circuit tie locations.

following five years. The following represents an overview of the additional spending SCE anticipates for each GMP technology area through 2028:

1. **E&P Software Tools** – Deploy next generation forecasting, capacity planning, and analytics capabilities to further integrate DERs and Microgrid into SCE's system planning processes, and streamline the generation and load interconnection processes.
2. **Communications** – Initiate and complete deployment of a new field area network, complemented with necessary upgrades to SCE's fiber optic network and deployment of common substation platform at each distribution substation.
3. **GMS** – Complete deployment of advanced grid and DER management applications necessary to support automated switching and DER optimization, including any necessary market functionalities.
4. **Automation** – Deploy modern automation on 25% to 50% of SCE's distribution circuits.
5. **DER Hosting Capacity Reinforcement** – Perform the necessary circuit upgrades to support integration of DERs forecasted in the IEPR DER forecast.
6. **Cybersecurity** – Continue to refine SCE's cybersecurity capabilities to keep pace with evolving cybersecurity threats.
7. **Microgrid Interfaces** – Perform demonstration projects to evaluate the technologies and processes necessary to interact with microgrids safely and efficiently.

3. <u>Status of DER-Related Technology Evaluation Projects</u>

To support SCE's longer term Grid Modernization objective of integrating DERs and creating opportunities for them to provide grid services, SCE evaluates pre-commercial technologies' potential to enhance the integration and management of DERs. The Commission's Electric Program Investment Charge (EPIC), the Department of Energy (DOE), and other collaborations provide SCE with opportunities to perform demonstrations of emerging technologies. These activities allow SCE to test strategies and technologies and provide vendor feedback, prior to full deployment. SCE's Grid Modernization testimony provides additional details on SCE's technology lifecycle management approach.[21] Table 4 provides high-level descriptions and the current status of SCE's DER-related projects.

[21] SCE-02 V.4 Pt. 1, Small-scale Deployments Program Description.

Table 4
DER-Related Technology Evaluations

Project ID	Name	Description	Program	Project Stage
IIM-13-0004	Integrated Grid Project	Demonstrate the next generation grid infrastructure to manage, operate and optimize the distribution system with high penetrations of DERs	EPIC I	Complete
IIM-13-0063	Distributed Optimized Storage (DOS)	Demonstrate end-to-end integration of multiple energy storage devices on a distribution circuit	EPIC I	Complete
IIM-14-0063	Integration of Big Data for Advanced Automated Customer Load Management	Enable 2030.5 server integration requirements with SCE back office systems	EPIC II	Complete
IIM-14-0070	Regulatory Mandates: Submetering Enablement Demonstration Phase 2	Develop electric vehicle submetering protocol	EPIC II	Execution
IIM-14-0080	Dynamic Power Conditioner	Demonstrate new hardware architecture that enables dynamic phase balancing and integrates more DERs	EPIC II	Execution
IIM-14-0086	UCI Microgrid Research, Development, and System Design (DE-FOA-0000997)	Facilitate the deployment of microgrids for greater grid resiliency by reducing the up-front cost and effort of engineering of microgrid controllers and improving the interoperability of components and future enhancements	O&M	Complete
IIM-15-0002	DRP Demo C - DER Integration	Manage DER through an aggregator to eliminate distribution circuit overloading	DRP	Not Advanced
IIM-15-0007	DRP Demo E - Microgrid	Demonstrate the capability of managing and operating multiple DERs within a microgrid system	DRP	Not Advanced
IIM-17-0001	Electric Access System Enhancement (EASE)	Demonstrate technology and rules required to increase solar PV and DER adoption by facilitating information exchange, developing a system of systems control architecture and optimization of resources	DOE	Execution
GT-18-0003	Storage-Based Distribution DC Link	Demonstration proposing architecture allowing energy storage systems to connect to two unique distribution circuits	EPIC III	Initiation
GT-18-0004	Integrated Grid Project Phase 3	This project supports SCE's filed Distribution Resource Plan (DRP) demonstration D	EPIC III	Initiation
GT-18-0005	Smart City Demonstration	Improve planning processes that include understanding customer technology adoption and increased integration with city planning and DER permitting	EPIC III	Planning
GT-18-0006	Next Generation Distribution Automation III	The project objective is to demonstrate future advanced capabilities to manage the grid with higher distributed energy resources	EPIC III	Initiation
GT-18-0010	Distribution Optimal Power Flow	Demonstration of Optimal Power Flow Engine applied to distribution systems to help manage DER that are dispersed and non-inertia driven	EPIC III	Initiation
GT-18-0015	Vehicle-to-Grid Integration Using On-Board Inverter	Evaluate discharging power to the grid from the Vehicle battery. Understand Vehicle to Grid interconnection issues, support integration of resources to SCE's new back office applications, evaluate related technologies and standards (IEEE 2030.5)	EPIC III	Planning
GT-18-0016	Distributed Plug-In Electric Vehicle Charging Resources	Demonstrate plug-in electric vehicle fast charging stations with integrated energy storage that can respond to grid needs	EPIC III	Planning
GT-18-0017	Service and Distribution Centers of the Future	Demonstrate an advanced SCE service center, housing electrified trucks, and workplace charging in a high DER area.	EPIC III	Planning
GT-18-0018	Control and Protection for Microgrids and Virtual Power Plants	Testing SCE distribution systems that include DER used for nested microgrids	EPIC III	Planning
GT-18-0019	Distributed Energy Resources Dynamics Integration Demonstration	Understand dynamics of DERs using real-time hardware-in-the-loop	EPIC III	Planning
GT-18-0020	Distributed Energy Resource Protection and Control of Distribution Networks	Examine impact of high penetrations of DER on SCE's existing protection and control practices	EPIC III	Initiation
GT-18-0021	Predictive Distribution Reliability	Evaluate reliability impacts of DERs through a novel predictive methodology	EPIC III	Initiation
IIM-18-0042	Grid Resilience Intelligence Platform (GRIP)	Develop tools via advanced analytics that help anticipate, absorb and recover from disruptive grid events, and how DERs can absorb grid events and help reduce recovery time.	O&M	Planning

C. **Foundational Technologies**

Grid Modernization is intended to accelerate the adoption and integration of renewables and other sustainable resources on the distribution grid in accordance with California Public Utilities Code §769.[22] The Commission has defined a modern grid as:

> 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 grid 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.[23]

SCE has distilled this definition into three primary Grid Modernization functions. A modern grid should be able to:

1. Integrate DERs into system planning and grid operations
2. Enable DERs to fully utilize their capabilities to realize their value
3. Achieve safety and reliability through technology innovation

SCE defines foundational technologies as system-level technologies that are necessary under all realistic DER-growth scenarios to enable these three functions. The four foundational technologies include the E&P software tools,[24] communications,[25] cybersecurity, and the grid management system (GMS). Table 5 summarizes the foundational attributes of these technologies and describes how they improve upon the capabilities of the traditional solutions.

---

[22] Interpreted by the California Public Utilities Commission (Commission) in Decision No. (D.) 18-03-023 in the Distribution Resources Plan (DRP) proceeding R.14-08-013.

[23] D.18-03-023, p. 7.

[24] E&P software tools include the Grid Connectivity Model, Grid Analytics Application (GAA), Long-term Planning Tool-System Modeling Tool (LTPT-SMT), Grid Interconnection Processing Tool (GIPT), and Distribution Resources Plan External Portal (DRPEP).

[25] Communications includes the Field Area Network (FAN), Common Substation Platform (CSP), and Wide Area Network (WAN).

Table 5
Foundational Technologies

Technology Category	Technology	Foundational Attributes	Improvements over Traditional Solution
E&P Software Tools	GCM	Provides the electrical network hierarchy and connectivity model that underpins the other E&P tools and GMS	Transitions from multiple disconnected models to a single integrated electrical network model
	GAA	Performs analytics on grid data and provides hourly historical load and generation profiles to support the DIDF processes	Enables grid analytics and cleansed profiles to migrate from peak-based annual planning approach to annual hour-based profiles. Also provides aggregated customer/transformer load profiles for capacity planning.
	LTPT-SMT	Performs profile-based forecasting, power system analysis, and grid solution optimization in support of ICA, LNBA, GNA and DDOR	Enables integrated hourly system forecast and power flow analysis to enhance ICA results and identify, prioritize, and track optimal solutions for short- and long-term grid needs
	DRPEP	Publishes the ICA, LNBA, GNA and DDOR reports for external use	Provides interactive customer interface with up-to-date and immediate access to each circuit's capacity to integrate additional DERs
	GIPT	Provides a convenient online tool for customers to request DER interconnection that reduces total processing times	Streamlines, automates and accelerates customer interconnection process, eliminating the current paper-based, manual processes
Communications	FAN	Gathers real-time information from grid devices and transmits securely to centralized IT systems	Provides the advanced cybersecurity, data speed and capacity necessary to support SCE's advanced grid management capabilities (including device-to-device communications) that rely on internet protocol-based communications (as opposed to today's serial communications)
	CSP	Relays communications from the FAN to the WAN, provides decentralized computing capabilities for GMS, and hosts cyber-security at the substation-level	
	WAN	Provides high-speed communications between the CSP and centralized IT systems	
Cybersecurity		Ensures all communications and centralized IT systems are secure from cyber-vulnerabilities	Secures the entire field communications system and centralized IT systems from internet protocol-based cyber-security threats
GMS		Improves real-time situational awareness and grid analysis to support decision making related to avoiding or responding to abnormal conditions and optimizing the use of available grid resources (including DERs)	Improves upon the current distribution management system by integrating real-time data from a multitude of field devices to provide higher resolution situational awareness and by analyzing grid conditions in real-time to assist system operators in avoiding or responding to grid emergencies through assisted and automated switching, and optimizing all grid resources

As discussed earlier in the Grid Modernization Upgrade Status, SCE has deployed several E&P software tools and begun the implementation of cybersecurity tools. SCE will continue deploying these tools, along with communications and GMS technologies, during the 2021 GRC period. Additional details on each of these foundational technologies are provided in the GMP Requirements section.

D. <u>DER-Specific Integration Challenges</u>

In D.18-03-023, the Commission adopted a classification framework "to build a common vocabulary around different grid modernization technologies, the use cases, and the types of issues they resolve in order to frame the decision making questions that GRCs need to evaluate."[26] In response to D.18-03-023, OP 3, the three investor-owned utilities (IOUs) proposed updates to the Grid Modernization Classifications Tables, which the Commission approved in Resolution E-4982. Table 6 lists the DER integration challenges identified in the classification tables.[27]

Table 6
Potential System/Integration Challenges

1. Voltage Fluctuation	7. Fault Location and Service Restoration
2. Steady State Voltage Violations	8. Energy Market Security
3. Masked Load	9. Cybersecurity
4. Thermal	10. DER Aggregation Impacts on the Bulk Grid
5. Protection	11. DER Wholesale Market Participation
6. Operational Limitations	

Table 6 summarizes the integration challenges of each DER type,[28] the associated DER control approach,[29] and the distribution system upgrades necessary to address each challenge. Although this table identifies the integration challenges, the severity of these challenges is heavily impacted by (1) the degree of control that SCE or the market have over the DERs, (2) whether or not the focus of control is location specific (which allows SCE or the market to target specific issues more precisely) or system-wide (which is less precise), and (3) DER penetration levels and growth rates, which may be affected by SCE Tariff Rule 21 requirements, State policy incentives (e.g., California Solar Initiative, Self-Generation Incentive Program, and the Integrated Distributed Energy Resources proceeding), the ability to bid into wholesale markets at the interconnection (subject to CAISO rules), and DER market prices.

---

[26] D.18-03-023, p. 11.

[27] E-4982, Attachment B, pp. 43-45.

[28] Energy Efficiency is excluded since SCE does not foresee it causing any integration challenges.

[29] SCE has identified the three DER control types: (1) "autonomous" controls that are configured by a customer to suit their needs (including NEM customers without smart inverters, and energy storage without constrain management), (2) "global utility control" using signal that SCE sends system-wide to modify customer behavior (such as a save power day), and (3) "local utility control" using a signal that SCE sends to a specific resource or group of resources to modify customer behavior.

The mitigations underlined in bold text indicate differences between Table 7 and the Grid Modernization Classification Tables in Resolution E-4982.[30]

As shown in the table, certain integration challenges may more easily be resolved through direct utility control of the customer resources. One integration challenge, Energy Market Security, is not included in Table 7. To the extent any DERs participate in wholesale energy markets, this would be a potential integration challenge. This challenge would be addressed by the GCM, GMS, SA-3 and CSP, FAN and WAN.

SCE's plan for modernizing the grid will mitigate many of these DER integration challenges. However, SCE's Grid Modernization technologies and capabilities must be complemented by continued evolution of price incentives that engage DER owners as reliability partners with SCE.

[30] SCE's AL 3807-E proposed including these integration-challenge mitigations within the classification tables, but these proposals were not reflected in the classification tables adopted in Resolution E-4982.

Table 7
DER Integration Challenges and Mitigations

<table>
<tr><th>DER Type</th><th>Control Type</th><th>Anticipated DER Integration Challenges</th><th>Distribution System Upgrades Critical to Mitigating Each Challenge</th></tr>
<tr><td rowspan="2">Demand Response</td><td>Utility-controlled – Global</td><td>3. Masked Load
9. Cybersecurity</td><td rowspan="4">1. GCM, GMS, SA-3 and CSP, Volt/Var Optimization, FAN, WAN
2. GCM, GMS, DRPEP, GAA, GIPT, SA-3 and CSP, Volt/Var Optimization, FAN, WAN, Utility Owned Storage, Microgrid Interfaces
3. GCM, GMS, SA-3 and CSP, FAN, WAN <u>Grid Sensors, RFIs</u>
4. GCM, GMS, LTPT-SMT, DRPEP, GAA, GIPT, SA-3 and CSP, FLISR, RFIs, Grid Sensors, FAN, WAN, DER Hosting Capacity Reinforcement, Microgrid Interfaces
5. GCM, GMS (including Adaptive Protection), DRPEP, GAA, GIPT, SA-3 and CSP, FAN, WAN, Relay Replacement
6. GCM, GMS, LTPT-SMT, SA-3 and CSP, FLISR, RFIs, Grid Sensors, FAN, WAN, RCSs, Utility Owned Storage, Microgrid Interfaces
7. GCM, GMS, SA-3 and CSP, FLISR, FAN, WAN, Grid Sensors, <u>RFIs</u>
9. GMS, SA-3 and CSP, FLISR, RFIs, Grid Sensors, FAN, WAN
10. GMS, SA-3 and CSP, FLISR, RFIs, Grid Sensors, FAN, WAN, Utility Owned Storage, Microgrid Interfaces
11. GMS</td></tr>
<tr><td>Utility-controlled – Local</td><td>6. Operational Limitations
9. Cybersecurity</td></tr>
<tr><td>Photovoltaic</td><td>Autonomous or Utility-controlled</td><td>1. Voltage Fluctuation
2. Steady State Voltage Violations
3. Masked Load
4. Thermal
5. Protection
6. Operational Limitations
7. Fault Location and Service Restoration
9. Cybersecurity
10. DER Aggregation Impacts on Bulk Grid
11. DER Wholesale Market Participation</td></tr>
<tr><td>Photovoltaic with Energy Storage</td><td>Autonomous or Utility-controlled</td><td>1. Voltage Fluctuation
2. Steady State Voltage Violations
3. Masked Load
4. Thermal
5. Protection
6. Operational Limitations
7. Fault Location and Service Restoration
9. Cybersecurity
10. DER Aggregation Impacts on Bulk Grid
11. DER Wholesale Market Participation</td></tr>
</table>

Table 7 (cont'd)
DER Integration Challenges and Mitigations

<table>
<tr><th>DER Type</th><th>Control Type</th><th>Anticipated DER Integration Challenges</th><th>Distribution System Upgrades Critical to Mitigating Each Challenge</th></tr>
<tr><td>Energy Storage</td><td>Autonomous
Utility Controlled
(Global & Local)</td><td>1. Voltage Fluctuation
2. Steady State Voltage Violations
3. Masked Load
4. Thermal
5. Protection
6. Operational Limitations
7. Fault Location and Service Restoration
9. Cybersecurity
10. DER Aggregation Impacts on Bulk Grid
11. DER Wholesale Market Participation</td><td rowspan="4">3. GCM, GMS, SA-3 and CSP, FAN, WAN Grid Sensors, RFIs
4. GCM, GMS, LTPT-SMT, DRPEP, GAA, GIPT, SA-3 and CSP, FLISR, RFIs, Grid Sensors, FAN, WAN, DER Hosting Capacity Reinforcement, Microgrid Interfaces
5. GCM, GMS (including Adaptive Protection), DRPEP, GAA, GIPT, SA-3 and CSP, FAN, WAN, Relay Replacement
6. GCM, GMS, LTPT-SMT, SA-3 and CSP, FLISR, RFIs, Grid Sensors, FAN, WAN, RCSs, Utility Owned Storage, Microgrid Interfaces
7. GCM, GMS, SA-3 and CSP, FLISR, FAN, WAN, Grid Sensors, RFIs
9. GMS, SA-3 and CSP, FLISR, RFIs, Grid Sensors, FAN, WAN
10. GMS, SA-3 and CSP, FLISR, RFIs, Grid Sensors, FAN, WAN, Utility Owned Storage, Microgrid Interfaces
11. GMS</td></tr>
<tr><td rowspan="3">Electric Vehicles</td><td>Autonomous</td><td>1. Voltage Fluctuation
2. Steady State Voltage Violations
4. Thermal
5. Protection</td></tr>
<tr><td>Autonomous or Utility-controlled
(with Vehicle to Grid)</td><td>1. Voltage Fluctuation
2. Steady State Voltage Violations
3. Masked Load
4. Thermal
5. Protection
6. Operational Limitations
7. Fault Location and Service Restoration
9. Cybersecurity
10. DER Aggregation Impacts on Bulk Grid
11. DER Wholesale Market Participation</td></tr>
<tr><td>Utility Controlled – Global & Local
(for Demand Response)</td><td>3. Masked Load
6. Operational Limitations
9. Cybersecurity</td></tr>
</table>

E. Two-Way Power Flow Challenges

SCE's GMP addresses current and anticipated two-way power flow challenges on the distribution system. The following summarizes the technologies focused on two-way power flows:

- **Deploying modern distribution automation devices** to provide more granular situational awareness, sensing, and visualization of two-way power flows to anticipate and prevent safety and reliability issues resulting from equipment overloads and over-voltage.
- **Using advanced grid analytics and controls** to improve SCE's understanding of two-way power flows, anticipate potential grid events, and take preemptive action. This approach relies on Advanced Metering Infrastructure (AMI)-informed machine learning based predictive analytics, which also enhances situational awareness in areas with limited telemetry data.

- **Implementing fault location identification and service restoration (FLISR)** schemes that rely on high speed, device-to-device communications to provide faster outage detection, response, and recovery. This is particularly important for supporting two-way power flows, since the operational complexities they create could lead to longer outage durations without FLISR.
- **Ensuring that all DER interactions (within a grid with two-way power flows) are cyber-secure** to protect the confidentiality, integrity, and availability of utility and customer information and systems.
- **Deploying new grid planning and operations tools** that reduce the challenges two-way power flows create for system planners, operations engineers and system operators. The GIPT and DERMS will register, track and manage the DERs while GAA creates the load and generation profiles to distinguish load from generation.[31] The LTPT-SMT will use these profiles to perform annual load-profile based analysis to ensure the distribution system can support the forecasted two-way power flows. The GMS will also introduce advanced applications to optimize and control the distribution system.

F. DERs as Grid Services Providers

SCE's GMP identifies DER integration challenges, approaches to mitigating the challenges through distribution system upgrades, and the foundational technologies necessary for DERs to provide grid services. SCE's analysis of DER alternatives to mitigate DER-integration challenges concluded that either (1) there are no DER alternatives available or (2) that the distribution system upgrades are also necessary. Table 8 summarizes the distribution system upgrades and potential DER alternatives necessary to mitigate each DER-integration challenge. As with Table 7 above, the mitigations underlined in bold text indicate differences between Table 8 and the Grid Modernization Classification Tables in Resolution E-4982.[32]

---

[31] SCE recognizes that existing tariffs do not allow SCE to control DERs in this manner.

[32] SCE's AL 3807-E proposed including these integration-challenge mitigations within the classification tables, but these proposals were not reflected in the classification tables adopted in Resolution E-4982.

Table 8
Approaches to Mitigating DER-integration Challenges

DER Integration Challenge	Distribution System Upgrades Critical to Mitigating DER Integration Challenges	DER Alternatives *(upgrades needed to enable DER alternatives)*
1. Voltage Fluctuation	GCM, GMS, SA-3 and CSP, Volt/Var Optimization, FAN, WAN	No DER alternatives
2. Steady State Voltage Violation	GCM, GMS, DRPEP, GAA, GIPT, SA-3 and CSP, Volt/Var Optimization, FAN, WAN, Utility Owned Storage, Microgrid Interfaces	Multiple DERs (of all types) as part of a managed portfolio could provide this service. (DERMS required)
3. Masked Load	GCM, GMS, SA-3 and CSP, FAN, WAN, **Grid Sensors, RFIs**	No DER alternatives
4. Thermal	GCM, GMS, LTPT-SMT, DRPEP, GAA, GIPT, SA-3 and CSP, FLISR, RFIs, Grid Sensors, FAN, WAN, DER Hosting Capacity Reinforcement, Microgrid Interfaces	Multiple DERs (of all types) as part of a managed portfolio could provide this service. (DERMS required)
5. Protection	GCM, GMS (including Adaptive Protection), DRPEP, GAA, GIPT, SA-3 and CSP, FAN, WAN, Relay Replacement	No DER alternatives
6. Operational Limitations	GCM, GMS, LTPT-SMT, SA-3 and CSP, FLISR, RFIs, Grid Sensors, FAN, WAN, RCSs, Utility Owned Storage, Microgrid Interfaces	
7. Fault Location and Service Restoration	GCM, GMS, SA-3 and CSP, FLISR, FAN, WAN, Grid Sensors, **RFIs**	Multiple DERs (of all types) as part of a managed portfolio could provide this service. (DERMS and FLISR required to support; Microgrid Interfaces could also support)
8. Energy Market Security	GCM, GMS, SA-3 and CSP, FAN, WAN	No DER alternatives
9. Cybersecurity	GMS, SA-3 and CSP, FLISR, RFIs, Grid Sensors, FAN, WAN	
10. DER Aggregation Impacts on the Bulk Grid	GMS, SA-3 and CSP, FLISR, RFIs, Grid Sensors, FAN, WAN, Utility Owned Storage, Microgrid Interfaces	
11. DER Wholesale Market Participation	GMS	

G. Role of Existing and Customer Technologies in Achieving Objectives

SCE recognizes the importance of leveraging existing utility and 3rd party infrastructure to achieve its Grid Modernization objectives when it is possible and reasonable. SCE can leverage existing AMI, 3rd party communications networks, and smart inverters to improve the economic efficiency of the modernized electric grid.

The GAA will use SCE's AMI data to perform asset analytics[33] and system connectivity model analytics. The GAA will also use AMI data to improve the accuracy and granularity of load profiles. The LTPT-SMT will use these load profiles to generate annual hour-based load forecasts, as required for

33 This includes distribution asset health analytics.

the modernized annual distribution planning process.[34] LTPT-SMT also will use the AMI data to develop forecasts for distribution transformer loading. The GMS will use AMI data for short-term forecasting, to automatically detect wire-down and high impedance system faults[35], to improve the outage restoration process,[36] and to inform Distribution System State Estimation (DSSE).[37]

SCE will have the ability to interface with 3rd party communication networks to transact with DER aggregators. The IEEE 2030.5 communication protocol[38] will facilitate SCE communication with smart inverters and DER aggregators through the GMS. During the DER interconnection process, the GIPT will register smart inverters and provide this information to the GMS, which will improve SCE's ability to monitor and control DERs with smart inverters.

H. Overview of 2021 GRC Grid Modernization Request

Achieving SCE's Grid Modernization vision will require SCE to augment its grid planning and operations capabilities by deploying an integrated cyber-secure suite of automation, communications infrastructure, Grid Management System, and electric system forecasting and analytics applications, and ensuring available capacity to integrate DERs into the electric grid.

SCE's recent Grid Modernization efforts and accomplishments have focused on compliance with DRP decisions that require complex modifications to distribution grid planning and operations. The DRP proceeding includes three Tracks, of which Track 3 Policy, Sub-track 2 covers Grid Modernization, and Sub-track 3 covers Distribution Investment Deferral[39] as shown in Figure 2.

---

[34] D.17-09-026, Ordering Paragraph 5, pp. 59-60.

[35] A high-impedance fault results when an energized primary conductor comes in contact with a quasi-insulating object such as a tree, structure or equipment, or falls to the ground. These types of faults generally are not detected by conventional protective devices (i.e. circuit breakers, circuit automatic reclosers and branch line fuses).

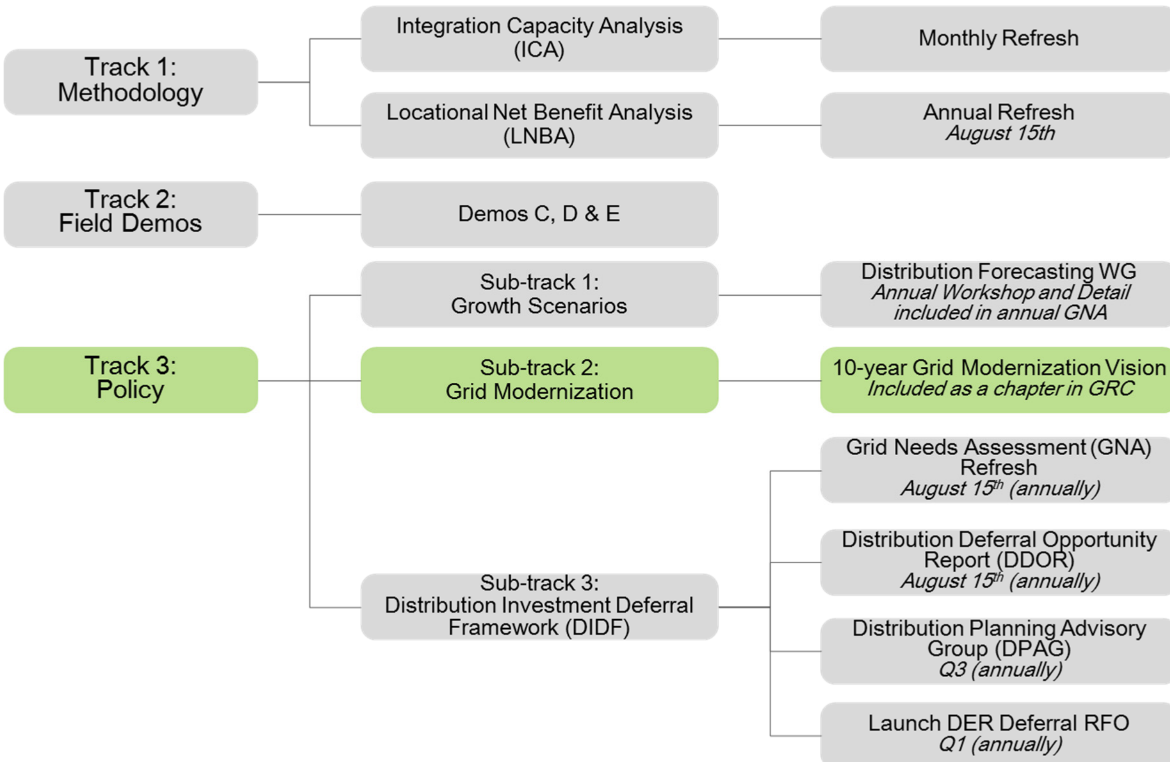
[36] This is to confirm that all customer load has been restored after a system fault.

[37] DSSE uses real-time grid data to estimate load and generation on the distribution system for real-time monitoring and analysis.

[38] IEEE 2030.5 defines the standard protocol used for interacting with smart inverters.

[39] D.18-03-023, for the Order Instituting Rulemaking (OIR) Regarding Policies, Procedures and Rules for the Development of Distribution Resources Plans (DRP) pursuant to Public Utilities Code Section 769.

Figure 2
Distribution Resources Plan (DRP) Structure and Deliverables



As discussed earlier in this GMP, SCE has developed and implemented short-term software enhancements and process improvements to satisfy the Sub-track 3 reporting requirements of the Grid Needs Assessment (GNA) and Distribution Deferral Opportunity Report (DDOR). SCE continues to investigate the appropriate methodologies to identify location-specific needs across the system. For example, D.18-02-004 requires SCE to provide more grid data publicly to facilitate opportunities for DERs to defer the need for traditional distribution infrastructure expenditures.[40] In compliance with Public Utilities Code Section 769 and commission decisions implementing Section 769 in R.14-08-013 and acting as a distribution grid operator, SCE will continue transforming its system planning process to support expansion of DERs while addressing system reliability and providing net customer benefits.[41]

---

[40] D.18-02-004, OP 2, pp. 83-89.

[41] *See* D.17-0-026, D.18-02-004, and D.18-03-023.

This includes developing planning tools that enable profile-based analysis[42] of all distribution grid assets, risk-based distribution portfolio management,[43] and locational net-benefits analysis.[44]

SCE is focused on addressing obsolescence of key software and communications technologies, which includes updating these systems with modern cyber-secure solutions. SCE will replace its aging Distribution Management System (DMS) and Outage Management System (OMS) that have limited functionalities with the GMS. The three primary components of the GMS include an Advanced Distribution Management System (ADMS), a Distributed Energy Resources Management System (DERMS) and advanced grid applications. The GMS will receive real-time information from field devices and DERs and analyze it to support grid operations in responding to (or preparing for) planned and unplanned outages and load/generation transfers. The GMS may evolve into a platform for a distribution system market in which DERs will be able to operate in a manner that is beneficial to distribution system operations and possibly meet wholesale energy needs in the California Independent System Operator (CAISO) market.

SCE's existing wireless field area network (FAN) is vulnerable to evolving cybersecurity threats and does not support SCE's planned automation capabilities. By replacing the FAN, expanding the fiber optic cable (wide area network or WAN), and adopting internet-based protocols, SCE will update the telecommunications vital to its automated grid functions, enhance cybersecurity, and implement automation that helps reduce or avoid customer outages. Expanding the WAN is necessary to provide connectivity between the FAN and GMS.

---

42 SCE's traditional forecasting approach consists of identifying a single point-in-time during the year when system load is highest, and then forecasting the growth in peak load over the forecasting period. Under the profile-based forecasting approach, annual load profiles with 8,760 data points (one for each hour in the year) are generated using historical grid data.

43 SCE is enhancing its annual grid planning processes to identify the grid need projects and consider DERs as potential alternatives for traditional grid infrastructure upgrades. This includes augmenting its project identification and scenario analysis capabilities so that SCE pursues projects that are risk-informed and benefit customers. The modified process helps to ensure sufficient resources are available to support projects from initiation to completion.

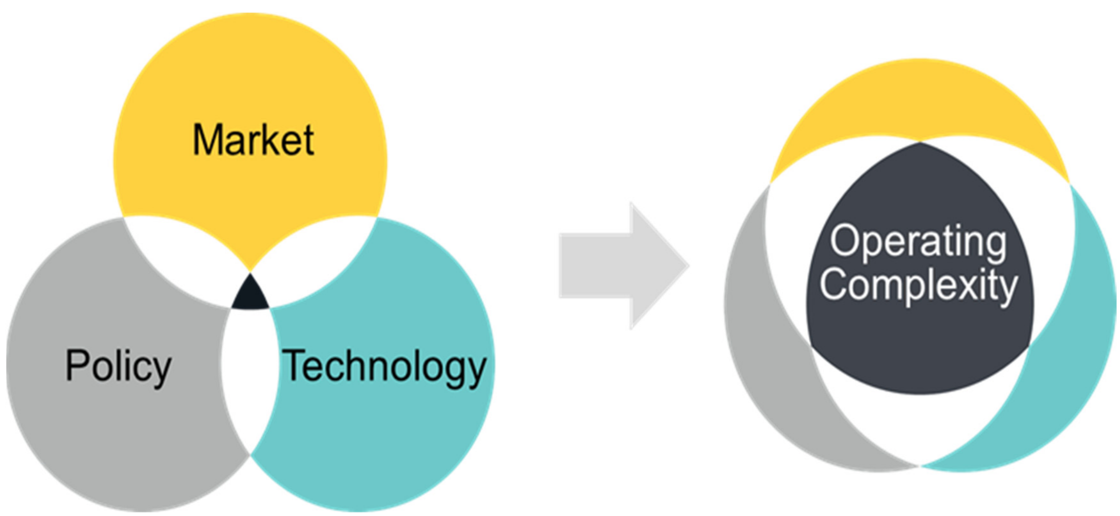
44 Assembly Bill (AB) 327 of 2013 added section 769 to the California Public Utilities Code, requiring each California Investor Owned Utility (IOU) to submit a DRP proposal "to identify optimal locations for the deployment of distributed resources…" using an evaluation of "locational benefits and costs of distributed resources located on the distribution system" based on savings distributed energy resources provide to the electric grid or costs to utility customers. Locational Net Benefits Analysis (LNBA), which evaluates DERs' benefits at specific locations is one of several new analytical methods needed to achieve the future envisioned in the DRP - one where DERs are deployed at optimal locations, times, and quantities so that their benefits to the grid are maximized and utility customer costs are reduced.

SCE forecasts $7.272 million in O&M in Test Year 2021 to manage all Grid Modernization deployment activities. SCE forecasts $821.8 million in capital expenditures in 2019 - 2023. This includes $120.3 million in engineering and planning software tool investments, $229.5 million in automation investments, $278.1 million in communications investments, $192.0 million in GMS investments, and $2.0 million in DER hosting capacity reinforcement investments.

1. Drivers

Three factors are driving the transformation of the electricity industry: market developments, state and federal policies, and technology considerations (illustrated in Figure 3). The acceleration and convergence of these factors is increasing the complexity and difficulty of planning and operating the distribution grid infrastructure.

Figure 3
Convergence of Industry Change Drivers



a) Market Drivers

A wider array of DER choices and financing options, and declining DER costs continue to drive increasing customer adoption of solar photovoltaic (PV), electric vehicles (EV), and other DERs.

b) **Policy Drivers**

Customer adoption of DERs is also being driven by state and federal policies and incentives, including California's Zero-Emission Vehicle (ZEV) program,[45] tax incentives, and upcoming changes to the Title 24 building standard.[46] The Commission's DRP proceeding has also introduced new requirements for integrating DERs into the California investor-owned utilities' (IOUs')[47] distribution planning processes.[48]

c) **Technology Drivers**

There are three key technology factors driving SCE's grid modernization: newly available technologies that will improve safety, reliability and wildfire resiliency; enhanced cybersecurity technologies will address evolving cybersecurity threats; and some existing SCE systems (such as DMS and NetComm) have become obsolete and require wholesale replacement.

d) **Operating Complexity**

New requirements for integrating DERs and technological improvements increase the complexity and difficulty of planning and operating the grid infrastructure. Challenges can include: (1) mismatches between peak generation and peak load; (2) masked load, reverse power flows, and power output fluctuations[49] that challenge grid operators in performing their primary role of maintaining grid safety and reliability; and (3) exceeding thermal, voltage, and other operating issues on specific circuit segments—which is often not visible to system operators using existing telemetry and operating tools.

---

45 The ZEV program is part of the California Air Resources Board's (CARB's) Advanced Clean Cars package of coordinated standards that controls smog-causing pollutants and GHG emissions of passenger vehicles in California. This program requires auto manufacturers to offer specific numbers of battery-electric, hydrogen fuel cell, and plug-in hybrid electric vehicles, calculated as a function of their total vehicle sales and vehicle types; the more electric driving range a vehicle has, the more credit it receives.

46 Title 24 building energy efficiency standards are designed to reduce wasteful, uneconomic, inefficient or unnecessary consumption of energy, and enhance outdoor and indoor environmental quality. These standards are updated every three years. The 2019 standards, which take effect January 1, 2020, require that all new homes include solar PV systems. The systems shall be sized to meet the home's annual electricity needs.

47 The IOUs include SCE, Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E).

48 *See* D.17-09-026, D.18-02-004, and D.18-03-023 in R.14-08-013.

49 D.18-03-023, Appendix C, Section E. pg. 7 "Distributed generation resources may be randomly intermittent, such as a cloud covering a solar panel. This intermittency causes voltage fluctuations and as a consequence, potential flicker."

2. Cost Summary of GRC Grid Modernization Plan

Table 9 summarizes SCE's 2021 GRC request for Grid Modernization, including all proposed investments that are identified within the Grid Modernization Classification Table. Table 9 also includes investments from multiple chapters within the T&D volume, and other volumes.

Table 9
Grid Modernization Capital Expenditure Summary
Recorded 2014-2018/Forecast 2019-2023, Nominal $000

		Recorded							Forecast		
	GRC Testimony Location	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Engineering and Planning Software Tools											
Grid Connectivity Model		$0	$485	$2,173	$4,911	$3,827	$8,417	$6,631	$8,174	$6,193	$4,843
Grid Analytics Applications		$0	$2,705	$5,000	$2,254	$7,853	$6,599	$5,684	$5,827	$6,129	$4,435
Long Term Planning Tool and System Modeling Tool	SCE-02 Vol. 4 Pt. 1 - Grid Modernization	$0	$978	$4,850	$18,169	$7,813	$7,790	$6,091	$5,650	$2,626	$2,195
Grid Interconnection Processing Tool		$0	$476	$1,172	$1,558	$3,016	$11,489	$5,424	$6,124	$0	$0
DRP External Portal		$0	$478	$1,082	$981	$1,980	$2,057	$1,315	$1,438	$2,780	$2,410
Engineering and Planning Software Tools Total		**$0**	**$5,121**	**$14,276**	**$27,873**	**$24,490**	**$36,352**	**$25,145**	**$27,213**	**$17,727**	**$13,883**
Communications											
Field Area Network		$0	$0	$478	$6,032	$11,823	$6,673	$8,638	$59,128	$72,377	$81,233
Distribution System Efficiency Enhancement Project	SCE-02 Vol. 4 Pt. 1 - Grid Modernization	$4,518	$4,309	$4,293	$4,846	$5,221	$5,412	$5,532	$5,532	$5,532	$5,532
Common Substation Platform		$0	$0	$180	$1,362	$2,467	$691	$629	$422	$4,149	$4,086
Wide Area Network		$0	$0	$513	$1,241	$1,982	$669	$659	$7,289	$1,983	$1,915
Communications Total		**$4,518**	**$4,309**	**$5,464**	**$13,481**	**$21,493**	**$13,445**	**$15,458**	**$72,371**	**$84,040**	**$92,766**
Grid Management System Total	SCE-02 Vol. 4 Pt. 1 - Grid Modernization	**$0**	**$0**	**$2,274**	**$7,851**	**$18,726**	**$33,064**	**$35,724**	**$47,611**	**$44,864**	**$30,682**
Automation											
Reliability-driven Distribution Automation	SCE-02 Vol. 4 Pt. 1 - Grid Modernization	$6,090	$7,141	$10,465	$17,817	$42,011	$61,526	$34,809	$23,872	$25,141	$25,356
DER-driven Distribution Automation		$0	$0	$0	$0	$0	$0	$590	$1,026	$843	$970
Small-scale Deployment		$0	$374	$1,112	$10,207	$3,938	$5,171	$7,633	$7,146	$5,599	$5,326
Reliability-driven Substation Automation*		$0	$248	$8,744	$19,966	$18,131	$6,701	$0	$0	$0	$0
DER-driven Substation Automation		$0	$0	$0	$0	$0	$0	$0	$4,000	$7,828	$5,965
Distribution Volt VAR Control*	Not included in the 2021 GRC	SCE has implemented DVVC, which will be migrated to GMS									
Automation Total		**$6,090**	**$7,763**	**$20,321**	**$47,990**	**$64,081**	**$73,398**	**$43,032**	**$36,044**	**$39,411**	**$37,617**
DER Hosting Capacity Reinforcement											
Subtransmission Relay Upgrade Program*	SCE-02 Vol. 4 Pt. 1 - Grid Modernization	$0	$0	$311	$1,319	$863	$491	$0	$1,488	$0	$0
DER-driven 4 kV Cutovers		$0	$0	$0	$0	$0	$0	$0	$9,058	$4,830	$8,390
DER-driven Substation Transformer Upgrades		$0	$0	$0	$0	$0	$0	$57	$843	$1,093	$0
DER-driven DSP Circuits	SCE-02 Vol. 4 Pt. 2 - Load Growth	$0	$0	$0	$0	$0	$0	$0	$17,138	$12,410	$13,445
DER-driven Circuit Breaker Upgrades		$0	$0	$0	$0	$0	$0	$455	$1,608	$2,409	$2,538
DER-driven Distribution Circuit Upgrades		$0	$0	$0	$0	$0	$0	$0	$13,876	$2,046	$3,303
DER Hosting Capacity Reinforcement Total		**$0**	**$0**	**$311**	**$1,319**	**$863**	**$491**	**$512**	**$44,011**	**$22,788**	**$27,676**
Cybersecurity	SCE-04 Vol. 3 - Cybersecurity	**$0**	**$0**	**$2,901**	**$14,499**	**$21,267**	**$25,702**	**$24,949**	**$45,145**	**$28,934**	**$36,426**
Energy Storage	SCE-02 Vol. 4 Pt. 1 - Energy Storage	**$3,743**	**$3,304**	**$733**	**$4,125**	**$9,270**	**$18,615**	**$19,290**	**$9,516**	**$0**	**$0**
Microgrid Interfaces	Not included in the 2021 GRC	There are no recorded or forecasted expenditures within this GRC period									

* SCE performs failure-based equipment replacements in each of these programs, and associated capital funding is requested in other volumes outside of Grid Modernization.

3. Grid Modernization Classification Tables

Table 10 reflects the Classification Tables as submitted in Advice 3996-E, with column I updated to reflect the 2021 GRC.

Table 10
Grid Modernization Classification Tables

A. Technology Category	B. Use Cases	C. Function	D. System wide or Local Deployment	E. Distribution System Management Activities and Responsibilities	F. System/ Integration Challenges Addressed	G. Relevant DERs	H. Applicable Grid Mod Technologies Related to DER Integration	I. Utility GRC Application Volume and Category
1. Grid Connectivity Model	HDA, S&R, GDS	Circuit modeling, Data Used for Forecasting and DER Value and Solution Analysis	System wide	Distribution Planning, Grid Operations, Market Operations	Items 1 - 8 of list of challenges	EV, DG, ES, EE, DR	Base data layer for ICA, Load and DER forecasting, state estimation, ArcGIS, EDGIS	SCE-2, Volume 4, Pt. 1, Ch. II, Section D, 1
2. Grid Management Systems (GMS)	HDA, GDS, S&R	All functions in the definitions, except for DER Value and Solutions Analysis	System wide	Distribution Grid Operations	All items	PEV, DG, ES, DR	Distributed Energy Resource Management System (DERMS), Advanced Distribution Management System (ADMS), Demand Response Management System (DRMS), DER Head-End, and VVO	SCE-2, Volume 4, Pt. 1, Ch. II, Section D, 3
3. Long and Short-term Planning Tools	HDA, S&R, GDS	DER Forecasting, DER Valuation Solution Analysis, Circuit Modeling	System wide	Distribution Planning	Thermal, Operational Limitations	EE, DR, EV, DG, ES	Integrated Load and DER forecasting, solution analysis for capacity/reliability, LoadSEER, Power flow modeling and analysis of distribution feeders (CYME) System Modeling Toolset (SMT); Long- Term Planning Tools (LTPT); Integration Capacity Analysis (ICA), Locational Net Benefit Analysis Tool (LNBA)	SCE-2, Volume 4, Pt. 1, Ch. II, Section D, 1
4. Data Sharing Portals	HDA, S&R, GDS	DER Valuation, Solution Analysis, Circuit Modeling	System wide	Distribution Planning	Sustained voltage violations, thermal, protection	EE, DR, EV, DG, ES	Data Sharing Portal (web interface) to publish Distribution Resources Plan data; Distribution Resource Plan External Portal (DRPEP)	SCE-2, Volume 4, Pt. 1, Ch. II, Section D, 1
5. Grid Analytics Application	HDA, S&R, GDS	Circuit/System Modeling	System wide	Distribution Planning Grid Operations	Sustained voltage violations, thermal, protection, asset management	EV, DG, ES, DR	Asset management, sensing and measurement (data), improves quality of asset data to improve distribution planning inputs and operational decisions	SCE-2, Volume 4, Pt. 1, Ch. II, Section D, 1
6. Interconnection Processing Tool	HDA, S&R, GDS	Application Assessment and Processing	System wide	Service Planning and Customer Engagement	Indirect impact on sustain voltage violations, thermal, protection interconnection process)	EV, DG, ES	Customer facing application to support streamlining the interconnection process, improve d distribution planning, Integration Capacity Analysis (ICA)	SCE-2, Volume 4, Pt. 1, Ch. II, Section D, 1

Table 10 (cont'd)
Grid Modernization Classification Tables

A. Technology Category	B. Use Cases	C. Function	D. System wide or Local Deployment	E. Distribution System Management Activities and Responsibilities	F. System/ Integration Challenges Addressed	G. Relevant DERs	H. Applicable Grid Mod Technologies Related to DER Integration	I. Utility GRC Application Volume and Category
7. Adaptive Protection System	S&R, HDA, GDS	Sensing & Measurement, Data & Device Communications, Control & Feedback Systems, Reliability Management,	Local & System wide	Grid Operations	Protection	All	This is typically incorporated as part of the Common Substation Platform (CSP) at the substation level. In the future, it may be incorporated into ADMS. (Capability in GMS for SCE)	SCE-2, Volume 4, Pt. 1, Ch. II, Section D, 3
8. Substation Automation and Common Substation Platform (CSP)	HDA, S&R, GDS	Sensing & Measurement, Data & Device Communications, Control & Feedback Systems, Reliability Management, Cybersecurity	Local & System Wide	Distribution Planning, Grid Operations, Market Operations	Items 1 - 10 of list of challenges	EV, DG, ES	SCADA, coordinated distribution device control with DERs, protection, cybersecurity	SCE-2, Volume 4, Pt. 1, Ch. II, Section D, 2 (CSP) and 4 (SA-3)
9. Volt/Var Optimization	HDA, S&R, GDS	Sensing & Measurement, Data & Device, Communications Control & Feedback Systems	Local	Distribution Planning, Grid Operations, Market Operations	Voltage fluctuation, sustained voltage violations, Low (Secondary) Voltage Controllers, Conservation Voltage Reduction	EV, DG, ES, DR	Substation Load Tap Changers, Voltage Regulators, Automated programmable capacitor controls, integration with GMS and/or DMS and EMS, future integration with smart inverters	SCE-2, Volume 4, Pt. 2, Ch. II, Section D, 4 (DVVC and PCC Replacement Program)
10. Fault Location, Isolation and Service Restoration (FLISR)	HDA, S&R, GDS	Sensing & Measurement, Data & Device Communications, Control & Feedback Systems, Reliability Management	Local	Distribution Planning, Grid Operations, Market Operations	Thermal, Operational Limitations, Fault Location & Service Restoration, Cybersecurity	EV, DG, ES, DR	Remote Intelligent Switches, Augmented Remote Control Switches, Automatic Reclosers, RCS retrofits	SCE-2, Volume 4, Pt. 1, Ch. II, Section D, 3 (software) and Section D, 4 (switches)
11. Remote Fault Indicators	S&R, HDA, GDS	Sensing & Measurement, Data & Device Comms.	Local	Distribution Planning, Grid Operations, Market Operations	Thermal, Operational Limitations, Cybersecurity	EV, DG, ES	Wireless bidirectional fault indicators, providing real time power flow characteristics	SCE-2, Volume 4, Pt. 1, Ch. II, Section D, 4
12. Field Area Network	S&R, HDA, GDS	Sensing and Measurement, Data & Device Communications, Cybersecurity	Large Local Areas, eventually system wide	Distribution Planning, Grid Operations, Market Operations	Items 1 - 10 of list of challenges	EV, DG, ES	Wireless radios, Routers	SCE-2, Volume 4, Pt. 1, Ch. II, Section D, 2
13. Wide Area Network	S&R, HDA, GDS	Sensing and Measurement, Data & Device Communications, Cybersecurity	Large Local Areas, eventually system wide	Distribution Planning, Grid Operations, Market Operations	Items 1 - 10 of list of challenges	EV, DG, ES	Fiber optic and IP connectivity	SCE-2, Volume 4, Pt. 1, Ch. II, Section D, 2
14. Grid Sensors	HDA, S&R, GDS	Sensing & Measurement, Data & Device Comms.	Local	Distribution Planning, Grid Operations, Market Operations	Thermal, Operational Limitations, Fault Location & Service Restoration, Cybersecurity	EV, DG, ES	Typically, incorporated with other devices/systems such as SCADA reclosers, and FLISR schemes. Telemetry included with the RFIs, RCS retrofits and RISs. This could also include Phasor Measurement Units (PMUs)	SCE-2, Volume 4, Pt. 1, Ch. II, Section D, 4

Table 10 (cont'd)
Grid Modernization Classification Tables

A. Technology Category	B. Use Cases	C. Function	D. System wide or Local Deployment	E. Distribution System Management Activities and Responsibilities	F. System/ Integration Challenges Addressed	G. Relevant DERs	H. Applicable Grid Mod Technologies Related to DER Integration	I. Utility GRC Application Volume and Category
15. Remote Controlled Switches	HDA, S&R	Control & Feedback Systems	Local	Distribution Planning, Grid Operations,	Operational Limitations	All	Typically, incorporated with other devices/ systems such as SCADA reclosers, and FLISR schemes.	SCE-2, Volume 4, Pt. 1, Ch. II, Section D, 4 ; SCE included retrofits of existing RCSs with enhanced telemetry
16. DER Hosting Capacity Reinforcement	HDA, GDS, S&R	Control & Feedback Systems	Local	Grid Operations	Thermal	All	Installing new manual switches, upgrading sections of cable/ conductor, extending feeder lines to create new ties	SCE-2, Volume 4, Pt. 1, Ch. II, Section D, 5 (Subtransmission Relay Upgrades) and SCE-2, Volume 4, Pt. 2, Ch. II, Section D, 2 (DER-driven load growth projects)
17. Relay Replacement	HDA, S&R	Control & Feedback Systems	Local	System Planning, Grid Operations	Protection	All	Upgrading legacy protection relays on as-needed basis	SCE-2, Volume 4, Pt. 1, Ch. II, Section D, 2 (SA-3)
18. Utility-Owned Storage	HDA, S&R	Sensing & Measurement, Control & Feedback, Reliability Management	Local	System Planning and Grid Operations	Voltage Violations, Thermal, Operational Limitations, DER Aggregation Impacts	DR, EV, DG, ES	Energy storage systems installed on the distribution systems to buffer DER output and load (PEV)	SCE-2, Volume 4, Pt. 1, Ch. IV, Section D, 1
19. Microgrid Interfaces	HDA, S&R	Sensing & Measurement, Control & Feedback, Reliability Management	Local	System Planning and Grid Operations	Voltage Violations, Thermal, Operational Limitations, DER Aggregation Impacts	DR, EV, DG, ES	"Trayer" switches and other hardware and software which allow DER powered microgrids to operate in islanded mode	N/A

I. Capital Budget

Table 11 summarizes SCE's ten-year capital expenditure forecast for Grid Modernization, including all proposed investments that are identified within the Grid Modernization Classification Tables. The first five years of the forecast (2019-2023) represent SCE's 2021 GRC forecast and the five-year forecast beyond the 2021 GRC period was prepared as a range. Due to the ten-year time horizon of this forecast, SCE is less certain about the last five years (2024-2028) since the cost estimation is based on longer-term projections about the rate of DER adoption, the evolution of wholesale energy markets, system reliability, and other factors that could influence SCE's Grid Modernization needs. The ranges in SCE's forecast are driven by the following key factors:

- **Requirement Uncertainty** for the E&P software tool enhancements and GMS in the later stage of the 10-year deployment.
- **Contract Timing** for the FAN. Given the timing of the 2018 GRC decision and the continuing evolution of communications technologies, SCE is continuing to evaluate its communications options to validate its current deployment approach.
- **Dynamic Drivers** of automation needs based on reliability performance of individual circuits, DER adoption rates, and other factors that influence SCE's automation needs on a circuit-specific basis. The lower range represents a continuation of adding one midpoint switch and one tie switch to 75 circuits per year (and only deploying RFIs on the DER-driven distribution automation circuits), while the higher range includes three midpoint switches and three tie switches to 75-180 circuits per year (and full automation on the DER-driven circuits).
- **DER Adoption Rates** above the 2017 IEPR forecast could trigger the need for additional DER hosting capacity reinforcement investments. The upper range assumes DER adoption is above the 2017 IEPR forecast, which would trigger a disproportionately larger need for additional DER hosting capacity. The forecast applies an additional 35% to account for this uncertainty.

Table 11
Grid Modernization 10 Year Capital Expenditure Summary
Recorded 2014-2018/Forecast 2019-2023 (Nominal $000)

	GRC Testimony Location	Forecast 2019	2020	2021	2022	2023	GMP Lower Range 2024 -2028	GMP Upper Range 2024 -2028
Engineering and Planning Software Tools								
Grid Connectivity Model	SCE-02 Vol. 4 Pt. 1 - Grid Modernization	$8,417	$6,631	$8,174	$6,193	$4,843	$2,000	$4,000
Grid Analytics Applications		$6,599	$5,684	$5,827	$6,129	$4,435	$8,000	$13,000
Long Term Planning Tool and System Modeling Tool		$7,790	$6,091	$5,650	$2,626	$2,195	$7,000	$11,000
Grid Interconnection Processing Tool		$11,489	$5,424	$6,124	$0	$0	$5,000	$7,000
DRP External Portal		$2,057	$1,315	$1,438	$2,780	$2,410	$2,000	$3,000
Engineering and Planning Software Tools Total		**$36,352**	**$25,145**	**$27,213**	**$17,727**	**$13,883**	**$24,000**	**$38,000**
Communications								
Field Area Network	SCE-02 Vol. 4 Pt. 1 - Grid Modernization	$6,673	$8,638	$59,128	$72,377	$81,233	$200,000	$300,000
Distribution System Efficiency Enhancement Project		$5,412	$5,532	$5,532	$5,532	$5,532	$5,000	$7,000
Common Substation Platform		$691	$629	$422	$4,149	$4,086	$16,000	$24,000
Wide Area Network		$669	$659	$7,289	$1,983	$1,915	$5,000	$8,000
Communications Total		**$13,445**	**$15,458**	**$72,371**	**$84,040**	**$92,766**	**$226,000**	**$339,000**
Grid Management System Total	SCE-02 Vol. 4 Pt. 1 - Grid Modernization	**$33,064**	**$35,724**	**$47,611**	**$44,864**	**$30,682**	**$54,000**	**$81,000**
Automation								
Reliability-driven Distribution Automation	SCE-02 Vol. 4 Pt. 1 - Grid Modernization	$61,526	$34,809	$23,872	$25,141	$25,356	$200,000	$800,000
DER-driven Distribution Automation		$0	$590	$1,026	$843	$970	$5,000	$100,000
Small-scale Deployment		$5,171	$7,633	$7,146	$5,599	$5,326		$35,000
Reliability-driven Substation Automation		$6,701	$0	$0	$0	$0		$0
DER-driven Substation Automation		$0	$0	$4,000	$7,828	$5,965	$5,000	$35,000
Distribution Volt VAR Control	Not included in the 2021 GRC	SCE has implemented DVVC, which will be migrated to GMS						
Automation Total		**$73,398**	**$43,032**	**$36,044**	**$39,411**	**$37,617**	**$245,000**	**$970,000**
DER Hosting Capacity Reinforcement								
Subtransmission Relay Upgrade Program	SCE-02 Vol. 4 Pt. 1 - Grid Modernization	$491	$0	$1,488	$0	$0	$0	$2,000
DER-driven 4 kV Cutovers	SCE-02 Vol. 4 Pt. 2 - Load Growth	$0	$0	$9,058	$4,830	$8,390	$40,000	$55,000
DER-driven Substation Transformer Upgrades		$0	$57	$843	$1,093	$0	$0	$4,000
DER-driven DSP Circuits		$0	$0	$17,138	$12,410		$70,000	$95,000
DER-driven Circuit Breaker Upgrades		$0	$455	$1,608	$2,409	$2,538	$30,000	$40,000
DER-driven Distribution Circuit Upgrades		$0	$0	$13,876	$2,046	$3,303	$20,000	$100,000
DER Hosting Capacity Reinforcement Total		**$491**	**$512**	**$44,011**	**$22,788**	**$14,231**	**$160,000**	**$295,000**
Cybersecurity	SCE-04 Vol. 3 - Cybersecurity	**$25,702**	**$24,949**	**$45,145**	**$28,934**	**$36,426**	**$130,000**	**$194,000**
Energy Storage	SCE-02 Vol. 4 Pt. 1 - Energy Storage	**$18,615**	**$19,290**	**$9,516**	**$0**	**$0**	**$0**	
Microgrid Interfaces	Not included in the 2021 GRC	**$0**	**$0**	**$0**	**$0**	**$0**	$9,000	$28,000

* SCE performs failure-based equipment replacements in each of these programs, and associated capital funding is requested in other volumes outside of Grid Modernization.

J. <u>Investment Capabilities</u>

Achieving SCE's 10-year Grid Modernization vision requires SCE to augment its capabilities for electric system planning and grid operations. Table 12 summarizes these high-level Grid Modernization capabilities and their associated technology investments. SCE's Grid Modernization GRC testimony provides detailed information, including investment requirements, for each capability.[50]

[50] SCE-02 V.4, Capital Expenditures for Grid Modernization section.

Table 12
Grid Modernization Capabilities and Supporting Investments

Capability Categories	High-level Capabilities	Supporting Technologies
Engineering & Planning Integrates DERs into grid planning processes	a. Enhanced analysis of the grid's capacity to integrate DERs and of the DERs' potential locational net benefits	GAA, LTPT-SMT, DRPEP, Cybersecurity
	b. Load and DER forecasting based on annual hour-based profiles	GAA, LTPT-SMT
	c. Grid needs assessment based on annual hour-based profiles	GAA, LTPT-SMT, DRPEP, Cybersecurity
	d. Risk-based distribution project portfolio management	LTPT-SMT
	e. Streamlined DER and load interconnection process	GIPT, Cybersecurity
	f. Electrical modeling and analysis of distribution system connectivity and hierarchy	GCM, GAA
Communications Enables the Grid Management System to communicate securely with DERs and other grid devices	a. Cyber-secure communications between distribution grid devices, substations and operations control centers	FAN, CSP, WAN, Cybersecurity
Grid Management Enables grid operators to monitor grid conditions in real-time and control field devices remotely	a. Advanced distribution and outage management	GMS, Distribution Volt/VAR Optimization and Capacitor Automation, Cybersecurity
	b. Grid reliability issue mitigation analysis	GMS, Cybersecurity
	c. DER state and constraint assessment	GMS, Cybersecurity
	d. DER grid services analysis	GMS, Cybersecurity
Automation Improves grid monitoring and control using real-time telemetry directional power flow data	a. Grid condition data collection and awareness	Distribution Automation, Substation Automation, Cybersecurity
	b. Automatic execution of grid reliability issue mitigations	Distribution Automation, Cybersecurity, Energy Storage, Micro Grid Interfaces
DER Integration Capacity Provides sufficient DER integration capacity to avoid circuit or equipment overloads due to DERs	a. Expanded DER integration capacity	DER Hosting Capacity Reinforcement

SCE's proposed Grid Modernization investments address the DER integration challenges identified in the Grid Modernization Classification Tables[51] while also enabling Grid Modernization functions. Table 13 summarizes the investments, dependencies (other enabling investments must be completed prior to the investments), the potential for SCE's proposed Grid Modernization investments to mitigate system integration challenges, and functions the investments provide.[52] This summary

[51] Resolution E-4982, Approval of Update to Grid Modernization Classification Tables, Attachment A.

[52] Grid services refers to the "Functions of Grid Modernization" included in E-4982, Attachment B, pp. 38-39.

complements the Grid Modernization capabilities in Table 12, which are also discussed in SCE's Grid Modernization testimony.[53]

Table 13
Grid Modernization Investments Addressing Integration Challenges and Grid Modernization Functions

Technology	Dependencies (other enabling investments)	System Integration Challenges Addressed	Grid Modernization Functions Enabled
Engineering & Planning Software Tools			
Grid Connectivity Model	Next generation Geographic Information System (GIS) and GMS	Voltage Fluctuations, Steady State Voltage Violations, Masked Load, Thermal, Protection, Operational Limitations, Fault Location and Service Restoration, Energy Market Security	Circuit Modeling, DER Forecasting, DER Value and Solutions Analysis
Grid Analytics Application	GCM	Steady State Voltage Violations, Thermal, Protection	Circuit Modeling
Long-term Planning Tool & System Modeling Tool	GCM and GAA	Thermal, Operational Limitations	DER Forecasting, DER Value and Solution Analysis, Circuit Modeling
Grid Interconnection Processing Tool	Cybersecurity	Steady State Voltage Violations, Thermal, Protection	Application Assessment and Processing
DRP External Portal	LTPT-SMT, GAA and GCM	Steady State Voltage Violations, Thermal, Protection	DER Value and Solutions Analysis, Circuit Modeling
Communications			
Field Area Network	Cybersecurity, CSP and WAN	All 11 integration challenges, except for DER Wholesale Market Participation	Sensing and Measurement, Data and Device Communications, Cybersecurity
Distribution System Efficiency Enhancement Project	None	Not applicable	Sensing and Measurement, Data and Device Communications
Common Substation Platform	Cybersecurity, FAN and WAN	All 11 integration challenges, except for DER Wholesale Market Participation	Sensing and Measurement, Data and Device Communications, Distribution Grid Control and Feedback, Reliability Management, Cybersecurity
Wide Area Network	Cybersecurity and CSP		Sensing and Measurement, Data and Device Communications, Cybersecurity
Cybersecurity	Grid Data Center Infrastructure, FAN, CSP, and WAN	Cybersecurity	Cybersecurity
Grid Management System	Distribution Automation	All 11 integration challenges	All functions except DER Value and Solutions Analysis

[53] SCE-02 V.4 Pt. 1, Overview section.

Table 13 (cont'd)
Grid Modernization Investments Addressing Integration Challenges and Grid Modernization Functions

Technology	Dependencies (other enabling investments)	System Integration Challenges Addressed	Grid Modernization Functions Enabled
Automation			
Reliability-driven Distribution Automation	GMS	Thermal, Operational Limitations, Fault Location and Service Restoration, Cybersecurity	Sensing and Measurement, Data and Device Communications, Distribution Grid Control and Feedback, Reliability Management
DER-driven Distribution Automation	GMS		
Small-scale Deployment	None		
Reliability-driven Substation Automation	GMS	All 11 integration challenges, except for DER Wholesale Market Participation	Sensing and Measurement, Data and Device Communications, Distribution Grid Control and Feedback, Reliability Management, Cybersecurity
DER-driven Substation Automation	GMS		
Distribution Volt/VAR Optimization and Capacitor Automation	GMS and Programmable Capacitor Controllers	Voltage Fluctuation, Steady State Voltage Violations	Sensing and Measurement, Data and Device Communications, Distribution Grid Control and Feedback
DER Hosting Capacity Reinforcement			
Subtransmission Relay Upgrade Program	None	Thermal	Distribution Grid Control and Feedback
DER-driven 4 kV Cutovers	None		
DER-driven Substation Transformer Upgrades	None		
DER-driven DSP Circuits	None		
DER-driven Circuit Breaker Upgrades	None		
DER-driven Distribution Circuit Upgrades	None		
Utility Owned Storage	GMS (DERMS) and Communications	Steady State Voltage Violations, Thermal, Operational Limitations, and DER Aggregation Impacts	Sensing and Measurement, Distribution Grid Control and Feedback, Reliability Management
Microgrid Interfaces	GMS (DERMS) and Communications		

SCE utilizes a technology lifecycle management approach, which includes testing each technology in a production environment before it is fully deployed to ensure that it will deliver the intended capabilities and benefits. Lab and/or field demonstrations allow SCE to confirm not only that the technologies will operate as intended, but to also gain valuable insight on the most effective deployment approach to minimize operational risks. Though SCE's proposed Grid Modernization technology investments have differing levels of technical maturity and commercialization, each will be tested through a small scale demonstration (or, for information technologies, extensive testing) prior to full deployment. Table 14 summarizes the maturity of each Grid Modernization technology, the expected useful life, and relevant equipment specifications.

Table 14
Grid Modernization Technology Profiles

Technology	Maturity	Expected Useful Life	Capacity, Ratings & Other Specifications
Engineering & Planning Software Tools			
Grid Connectivity Model	GCM is designed to operate as a web service using mature, industry standard development methods. Replacing SCE's legacy geo-spatial and geo-schematic applications.	5-10 years	Not applicable
Grid Analytics Application	While analytics programs are generally considered mature, their offerings to utility planning systems is limited. SCE will perform custom software development and integration. GAA is the first generation of SCE's grid analytics tool and will replace manual analytic routines.	5-10 years	Not applicable
Long-term Planning Tool & System Modeling Tool	Chosen technology is mature and widely used within the industry. Replacing legacy electric system planning tool (MDI).	5-10 years	Not applicable
Grid Interconnection Processing Tool	No commercially-available off-the-shelf product available. SCE will select a business process software platform and perform custom development and software integration. Replacing legacy toolset, including Load Growth Projects, Generation Interconnection Tool, PowerClerk, and the Interconnection Request Database (IReq).	5-10 years	Not applicable
DRP External Portal	Enabled using mature, industry standard, web technologies. Replacing the Distributed Energy Resource Interconnection Maps (DERiM), a temporary solution implemented to meet DRP requirements .	5-10 years	Not applicable
Communications			
Field Area Network	Proposed investment based on mature technology with adopted global standards	> 10 years	Not currently available
Distribution System Efficiency Enhancement Project	DSEEP includes legacy NetComm radios that have been in use for over two decade	5-10 years	Frequency Range – 902-928 MHz RF Baud Rates – 9.6 – 115.2 kbps Data Port RJ-45; 10/100 Mbps
Common Substation Platform	The CSP technology development is based on hardware hardening and redundancy while the software is based on virtualization and segmentation. Both are considered mature and the market has several options. Deployment of such computing platforms has been uncommon in utility substation environments, similar concepts have been deployed for other mission-critical applications such as those commonly found in Department of Defense applications. The CSP will be a net new component in SCE's distribution substation environment.	5-10 years	Available through confidential Cybersecurity briefings

Table 14 (cont'd)
Grid Modernization Technology Profiles

Technology	Maturity	Expected Useful Life	Capacity, Ratings & Other Specifications
Communications (continued)			
Wide Area Network	Fiber-optic wide area communication is a mature and proven technology and SCE already benefits from an approved standard for its planned WAN deployment.	5 years (routers & switches) 7 years (transport equipment) 20 years (fiber optic enclosures)	This data will become available after the FAN selection is finalized
Cybersecurity	The core foundational cybersecurity tools pertain to several technological development areas such as Network Access Control, Vulnerability Management, Threat Detection & Analysis, Certificate Management, and Identity Access Management. Although these areas benefit from mature products, there are ongoing and emerging developments and SCE partners with commercial and government organizations to test and evaluate the advancements made across the overall cybersecurity domain.	5+ years	Available through confidential Cybersecurity briefings
Grid Management System	The GMS includes two primary technological development areas. The first is the Advanced Distribution Management System (ADMS), which combines the Distribution Management System (DMS) and Outage Management System (OMS), which are traditionally split. ADMS products are widely available and have been deployed by many utilities nationwide. The ADMS will also incorporate **Adaptive Protection** capabilities as one of the GMS's advanced applications. The second is the DER Management System (DERMS). Through extensive industry analysis and procurement efforts, SCE has concluded that current DERMS products fall short in providing key DER management capabilities. SCE's strategy is therefore to partner with the selected ADMS vendor and incorporate DER management features within the ADMS platform itself. Once deployed, ADMS will replace SCE's legacy DMS and OMS, while the new DERMS solution will be new to SCE's production environment.	10 years (software) and 5-10 years (hardware)	Will be available once final vendor selections are complete

Table 14 (cont'd)
Grid Modernization Technology Profiles

Technology	Maturity	Expected Useful Life	Capacity, Ratings & Other Specifications
Automation			
Reliability-driven Distribution Automation DER-driven Distribution Automation	**Fault Location and Service Restoration (FLISR)** Implementing FLISR on circuits with high amounts of autonomous DERs requires intelligent automated switches, which are in the early stage of commercial deployment. It also requires additional validation of control logic, integrated with high-speed communications. SCE plans to enable FLISR on circuits with automation in 2022.	15-20 years (switches)	Load Break, Fault Interrupting, Pulse Reclosing
	Remote Controlled Switches (RCSs) RCSs are mature technologies with few application limitations. SCE has been retrofitting existing RCSs with Grid Sensors.	15-20 years	With or Without Grid Sensors and/or Fault Indications
	Remote Fault Indicators (RFIs) RFIs are currently limited to overhead devices and minimum power requirements, but SCE is testing underground and padmount devices, and expect to deploy them in 2020. RFIs are replacing the existing mechanical fault indicators.	10-15 years	Overhead, Underground, Low Current, Optical
Small-scale Deployment	This consists of limited-scale deployments of mostly early-commercial distribution automation technologies.	10-20 years	Not Applicable – Pilot Devices
Reliability-driven Substation Automation DER-driven Substation Automation	SA-3 equipment is in early commercial deployment and devices such as compatible relays are available from several vendors. SA-3 is an interoperable platform that, together with the CSP, can facilitate data exchange over IEC 61850 protocols. Vendor support of IEC 61850 is growing, but is still in the early stage.	10-15 years	Not Applicable – Hundreds of components
Distribution Volt/VAR Optimization and Capacitor Automation	DVVC has been an advanced application within SCE's DMS for about five years. Future advanced include incorporating smart inverter and AMI data to improve its precision and to implement volt/VAR optimizing 3-phase voltage across all capacitors.	7 years (software)	Voltage and VAR Optimization

Table 14 (cont'd)
Grid Modernization Technology Profiles

Technology	Maturity	Expected Useful Life	Capacity, Ratings & Other Specifications
DER Hosting Capacity Reinforcement			
Subtransmission Relay Upgrade Program	DER hosting capacity reinforcement grid upgrades use traditional techniques, although the E&P software tools that providing the methods for identifying violations and potential mitigations are new. The solutions SCE is using to mitigate DER-caused violations have been used in the traditional planning process to mitigate forecasted violations by replacing different pieces of equipment to ensure operations are within hardware limits.	15-30 years (same as traditional infrastructure upgrades)	Same as traditional infrastructure upgrades
DER-driven 4 kV Cutovers			
DER-driven Substation Transformer Upgrades			
DER-driven DSP Circuits			
DER-driven Circuit Breaker Upgrades			
DER-driven Distribution Circuit Upgrades			
Utility Owned Storage	Lithium-ion (Li-ion) battery technology is commercially available and fully supported by several well-established vendors, and therefore has been suitable for capital investment since SCE's 2015 GRC. Energy storage investments through 2023 will continue to be based on Li-ion technology. Many other battery technologies are under development and may be ready for capital deployment after 2023, but as of 2019 it is too soon to predict whether any other technologies may become production ready within the 2021 GRC period.	15 years	Utility-owned storage system capacity, at the distribution level, is sized in terms of MW and MWh on a case-by-case basis, depending on project-specific requirements. System sizes in the DESI program range from 1-4 MW and 3-9 MWh. The two Aliso Canyon systems are each 10MW and 40MWh. Systems are typically connected at 12kV but connection at any primary distribution voltage is possible with appropriate transformation.
Microgorid Interfaces	Microgrid interfaces (involving microgrids visible to utility operations) are currently in the demonstration stage of commercialization. SCE expects to demonstrate new capabilities in this area through its EPIC III demonstration projects.	15-20 years (same as other intelligent switches)	Not currently available

K. <u>Investment Justification</u>

In its 2021 GRC request, SCE describes the three industry change drivers – Market, Policy and Technology – that are transforming the electric industry and driving each of the technology investments included in SCE's Grid Modernization request.[54] Table 15 summarizes the primary investment driver of each Grid Modernization investment (as defined by D.18-03-023[55]), which complement the industry

[54] SCE-02 V.4 Pt. 1, Overview section.

[55] D.18-03-023, Attachment A (Grid Modernization Submission Requirements), footnote 2, pp. 2-3, defines investment drivers as follows "Drivers may include (a) Supporting targeted distribution deferral with DERs; (b) Accommodate autonomous DER growth that has socialized interconnection costs; (c) Ensure system safety; meets outcomes of Safety Model Assessment Proceeding (SMAP) and Risk Assessment Mitigation

change drivers SCE describes in testimony. This table also includes the percentage of the costs attributable directly to DER integration versus safety and reliability, the DERs that the technology integrates, and the alternatives that SCE considered in lieu of the proposed investments. The cost allocations were derived based on a review of the drivers for each workstream.

Phase (RAMP); (d) Maintaining reliability while expanding DER; (e) Increasing reliability for Worst Performing Circuit Rehabilitation (WCR) circuits; (f) Increasing reliability system wide."

Table 15
Investment Drivers and Alternatives Considered

Technology	Primary Investment Driver	Cost Driver Split		DERs Integrated	Alternatives Considered
		DER Integration	Safety & Reliability		
Engineering & Planning Software Tools					
Grid Connectivity Model	Maintaining reliability while expanding DER	20%	80%	All DER types	Legacy geo-spatial and geo-schematic applications
Grid Analytics Application	Maintaining reliability while expanding DER	20%	80%	All DER types	Historical manual processes
Long-term Planning Tool & System Modeling Tool	Targeted distribution deferral with DERs	50%	50%	All DER types	Legacy software tool (MDI or Master Distribution Interface) and various manual processes.
Grid Interconnection Processing Tool	Accommodate autonomous DER growth	100%	0%	DG, ES, DR	Various stand-alone legacy systems
DRP External Portal	Targeted distribution deferral with DERs	100%	0%	DG, ES, DR	Temporary DERiM solution, replaced in December 2018 with DRPEP
Communications					
Field Area Network	Maintaining reliability while expanding DER	10%	90%	EV, DG, ES	Alternatives include continuing to rely on legacy NetComm system and using a public carrier network
Distribution System Efficiency Enhancement Project	Maintaining reliability while expanding DER	0%	100%	EV, DG, ES	No alternatives considered
Common Substation Platform	Maintaining reliability while expanding DER	10%	90%	EV, DG, ES	Multiple different computing devices and firewall appliances
Wide Area Network	Maintaining reliability while expanding DER	10%	90%	EV, DG, ES	Wireless radio solution
Cybersecurity	Maintaining reliability while expanding DER	10%	90%	EV, DG, ES, DR	Available through confidential cybersecurity briefing
Grid Management System	Maintaining reliability while expanding DER	25%	75%	EV, DG, ES, DR	Continue using legacy DMS/OMS
Automation					
Reliability-driven Distribution Automation	Increasing reliability for worst performing circuits	0%	100%	EV, DG, ES, DR	Various other scoping options with more midpoint and circuit tie switches
DER-driven Distribution Automation	Increasing reliability while expanding DER	100%	0%	EV, DG, ES, DR	Various other scope options beyond simply deploying RFIs
Small-scale Deployment	Increasing reliability for worst performing circuits	Not applicable	Not applicable	EV, DG, ES, DR	No alternatives considered
Reliability-driven Substation Automation	Increasing reliability for worst performing circuits	0%	100%	EV, DG, ES, DR	Maintain legacy substation automation systems
DER-driven Substation Automation	Increasing reliability while expanding DER	100%	0%	EV, DG, ES, DR	Maintain legacy substation automation systems

Table 15 (cont'd)
Investment Drivers and Alternatives Considered

Technology	Primary Investment Driver	Cost Driver Split		DERs Integrated	Alternatives Considered
		DER Integration	Safety & Reliability		
Automation (continued)					
Distribution Volt/VAR Optimization and Capacitor Automation	Conservation voltage reduction	0%	100%	EV, DG, ES, DR	Continuing with existing volt/VAR control capabilities that do not leverage AMI or smart inverter data
DER Hosting Capacity Reinforcement					
Subtransmission Relay Upgrade Program	Accommodate autonomous DER growth	100%	0%	All DER types	No realistic alternatives currently available
DER-driven 4 kV Cutovers	Accommodate autonomous DER growth	100%	0%	All DER types	No realistic alternatives currently available
DER-driven Substation Transformer Upgrades	Accommodate autonomous DER growth	100%	0%	All DER types	No realistic alternatives currently available
DER-driven DSP Circuits	Accommodate autonomous DER growth	100%	0%	All DER types	No realistic alternatives currently available
DER-driven Circuit Breaker Upgrades	Accommodate autonomous DER growth	100%	0%	All DER types	No realistic alternatives currently available
DER-driven Distribution Circuit Upgrades	Accommodate autonomous DER growth	100%	0%	All DER types	No realistic alternatives currently available
Utility Owned Storage	Supporting targeted distribution deferral with DERs	100%	0%	EV, DG, ES, DR	Traditional grid infrastructure upgrades
Microgrid Interfaces	Maintaining reliability while expanding DER	100%	0%	EV, DG, ES, DR	Traditional grid infrastructure upgrades

L. <u>Operations and Maintenance (O&M) Expenses</u>

SCE's has forecasted the O&M expenses to support and maintain the respective Grid Modernization technologies as summarized in Table 16.

Table 16
Forecast O&M Expense
(Nominal 2018 $000)

	Forecast					GMP Lower Range	GMP Upper Range
	2019	2020	2021	2022	2023	2024 -2028	
T&D Deployment Readiness	$1,736	$1,540	$1,539	$1,540	$1,539	$8,000	$8,000
T&D Automation Maintenance						$12,000	$49,000
IT Project Support	$3,766	$5,410	$5,734	$5,410	$5,734	$13,000	$20,000
Service Management Office and Operations	$0	$4,300	$9,200	$6,300	$6,100	$23,000	$35,000
Grid Network Solutions			$3,188	$4,501	$8,572	$34,000	$51,000
Totals	**$5,502**	**$11,249**	**$19,660**	**$17,750**	**$21,944**	**$90,000**	**$163,000**

M. Status of Currently Funded Projects

Some of SCE's Grid Modernization investments will be completed within the 2018 GRC period—such as distribution automation upgrades to particular circuits or software releases—while others will span multiple GRC cycles, such as the FAN. The delay in the 2018 GRC decision limited SCE's ability to fully deploy some planned software tools. Table 17 summarizes the deployment status of each Grid Modernization investment, whether it was authorized in the 2018 GRC, and if the authorized deployments are incomplete.

Table 17
Deployment Status of 2018 GRC-authorized Investments

Technology	Authorized in 2018 GRC	Deployment Status	Authorized in 2018 GRC, but Deployment Incomplete
Engineering & Planning Software Tools			
Grid Connectivity Model	✓	Initial release supported ICA with as-build connectivity model, field device setting information for capacitor banks and automatic reclosers, and other key asset data.	✓
Grid Analytics Application	✓	Initial release implemented annual hour-based profile processing platform with automatic cleansing process.	✓
Long-term Planning Tool & System Modeling Tool	✓	Initial releases enabled ICA and publishing results via DRPEP. Also implemented the base functionality for the forecasting engine.	✓
Grid Interconnection Processing Tool	✓	Initial implementations scheduled to occur in 2019 and 2020. Efforts to-date included evaluating vendor solutions and conducting proofs-of-concept.	✓
DRP External Portal	✓	Implemented foundational information sharing capabilities based on Commission guidance in the DRP.	✓
Communications			
Field Area Network	✓	Conducted competitive procurement process and performed lab evaluations of multiple vendor products.	✓
Distribution System Efficiency Enhancement Project	✓	Performed upgrades to legacy NetComm system on an as-needed basis.	
Common Substation Platform	✓	Conducted competitive procurement process and selected a vendor.	✓
Wide Area Network		Deployment deferred to align with FAN and CSP deployments.	
Cybersecurity	✓	Completed architecture assessment and designs based on the need of the overall Grid Mod program; Initiated the procurement of all core foundational cybersecurity tools for implementation at the Grid Data Centers. Supported the requirements definition for various workstreams including FAN, CSP, WAN, and GMS.	✓
Grid Management System	✓	Engaged other large utilities to learn from their ADMS deployments and assess maturity of vendor products, and conducted competitive solicitation.	✓
Automation			
Reliability-driven Distribution Automation	✓	Deployed modern automation on 73 circuits in 2018.	✓
DER-driven Distribution Automation	✓	No deployments.	✓
Small-scale Deployment	Not applicable	Performed small-scale deployments of multiple RFI types.	Not applicable

Table 17 (cont'd)
Deployment Status of 2018 GRC-authorized Investments

Technology	Authorized in 2018 GRC	Deployment Status	Authorized in 2018 GRC, but Deployment Incomplete
Automation (continued)			
Reliability-driven Substation Automation		Completed SA-3 deployments at 13 substations.	
DER-driven Substation Automation		No deployments.	
Distribution Volt/VAR Optimization and Capacitor Automation	✓	Fully deployed on SCE's system.	
DER Hosting Capacity Reinforcement			
Subtransmission Relay Upgrade Program		Initiated upgrade in the Viejo subtransmission system, expected to be complete in 2021 and used as a pilot.	
DER-driven 4 kV Cutovers	✓	Project initiation expected by YE 2019.	✓
DER-driven Substation Transformer Upgrades	✓	Not requested in 2018 GRC, projects not yet initiated. Project initiation expected by YE 2019.	✓
DER-driven DSP Circuits	✓	Project initiation expected by YE 2019.	✓
DER-driven Circuit Breaker Upgrades	✓	Project initiation expected by YE 2019.	✓
DER-driven Distribution Circuit Upgrades	✓	Project initiation expected by YE 2019.	✓
Utility Owned Storage	✓	Three in operation and eight to complete deployment in 2020-2021	✓
Microgrid Interfaces	Not applicable	Not applicable	Not applicable

N. Cost Reasonableness

SCE followed the guidance from the Commission's DRP Track 3, Sub-track 2[56] decision (DRP Decision) to develop the Grid Modernization investments proposed in its 2021 GRC. The DRP decision directed the IOUs to use one of two methods to assess investments that improve safety and reliability: (1) traditional reliability metrics, which the DRP Decision identifies as Option 1; or (2) a lowest cost approach, which the DRP decision identifies as Option 3.[57] To determine the cost-reasonableness of investments driven by DER integration, SCE used Option 3.

Table 18 summarizes the method used to demonstrate the cost-reasonableness of each proposed investment.

[56] D.18-03-023.

[57] D.18-03-023, at pp. 22-27. The DRP decision also included an Option 2, which the Commission concluded was infeasible, and an Option 4, which applies to the Integrated Resource Plan (IRP) proceeding.

Table 18
Cost-Reasonableness Approach for Grid Modernization Investments

Technology	Cost-Reasonableness Approach		Overview
	Option 1	Option 3	
Engineering & Planning Software Tools			
Grid Connectivity Model		✓	Developing in-house with SCE and contract labor with pre-negotiated rates
Grid Analytics Application		✓	Performed competitive solicitations that resulted in preferred vendors
Long-term Planning Tool & System Modeling Tool		✓	Performed competitive solicitations that resulted in preferred vendors
Grid Interconnection Processing Tool		✓	Performed competitive solicitations that resulted in a preferred vendor
DRP External Portal		✓	Performing development and integration internally with SCE and contract labor using a commercially available GIS platform
Communications			
Field Area Network		✓	Performed competitive solicitation that resulted in preferred vendor
Distribution System Efficiency Enhancement Project		✓	Single vendor, no alternative considered
Common Substation Platform		✓	Performed competitive solicitations that resulted in a preferred vendor
Wide Area Network		✓	Considered a wireless option, which was considerably more expensive
Cybersecurity		✓	Available through confidential Cybersecurity briefing
Grid Management System	✓		Benefit-cost analysis that compares the value of reliability improvements to the customer against the cost of deploying and maintaining the GMS

Table 18 (cont'd)
Cost-Reasonableness Approach for Grid Modernization Investments

Technology	Cost-Reasonableness Approach		Overview
	Option 1	Option 3	
Automation			
Reliability-driven Distribution Automation	✓		Benefit-cost analysis that compares the value of reliability improvements to the customer against the cost of deploying and maintaining the automation
DER-driven Distribution Automation		✓	Proposing RFIs for high-DER circuits in lieu of fully automating these circuits with additional midpoint switches
Small-scale Deployment		✓	Alternative is to pursue deployments through Reliability-driven DA program, which could result in additional deployment risks
Reliability-driven Substation Automation		✓	Alternative is to pursue failure-based replacement strategy (i.e., upgrading the substations to SA-3 following a relay failure)
DER-driven Substation Automation		✓	Alternative is to pursue failure-based replacement strategy
Distribution Volt/VAR Optimization and Capacitor Automation			DVVC deployment is complete, so a cost-reasonableness assessment is unnecessary
DER Hosting Capacity Reinforcement			
Subtransmission Relay Upgrade Program		✓	No alternatives considered. SCE is seeking recovery of one pilot-based installation within the Viejo subtransmission system, and seeks no additional funding in 2021 GRC
DER-driven 4 kV Cutovers		✓	An alternative to cutting over to a standard voltage circuit is to perform a 4 kV network upgrade. This alternative is either higher cost or delivers less value over time since 4kV is an aging and obsolete system, as described in SCE.02 V.04 Pt. 2 Section II. Load Growth, Section D (4kV Cutovers-Load Growth Driven).
DER-driven Substation Transformer Upgrades		✓	An alternative is to build new circuits and/or perform circuit upgrades to facilitate transfers between substations. The circuit upgrade and/or new circuit alternative is not selected because they are higher cost, have community impacts, environmental impacts and/or deliver less value over time as described in SCE.02 V.04 Pt. 2 Section II. Load Growth, Section D (Distribution Substation Plan).
DER-driven DSP Circuits		✓	An alternative to constructing a new circuit is to upgrade the capacity of an existing circuit. This alternative is not selected either because the upgrade is uneconomical or because the upgrade fails to meet the need over time as described in in SCE.02 V.04 Pt. 2 Section II. Load Growth, Section C (Distribution & Subtransmission Planning Process).
DER-driven Circuit Breaker Upgrades		✓	No alternatives considered
DER-driven Distribution Circuit Upgrades		✓	An alternative is to construct a new circuit where one is not warranted. This alternative is not selected because the new circuit would be uneconomical.

Table 18 (cont'd)
Cost-Reasonableness Approach for Grid Modernization Investments

Technology	Cost-Reasonableness Approach		Overview
	Option 1	Option 3	
Utility Owned Storage		✓	No alternatives considered. The 2021 GRC funding is for pilot projects that are expected to prepare SCE to use storage as a planning and operational tool
Microgrid Interfaces			No funding requested in the 2021 GRC, so a cost-reasonableness assessment is unnecessary

O. Information for Locational Investment

The DRP defines locational investments as "… hardware that is installed on the distribution system to meet a circuit or location specific grid need."[58] SCE investments that meet this definition include the following numbered items from the DRP's Grid Modernization Classification Tables:[59]

8. Substation Automation and Common Substation Platform
9. Volt/Var Optimization
10. Fault Location, Isolation and Service Restoration
11. Remote Fault Indicators
14. Grid Sensors
15. Remote Controlled Switches
16. DER Hosting Capacity Reinforcement
17. Relay Replacement
18. Utility Owned Storage
19. Microgrid Interfaces

1. Automation

Locational investments are largely performed within Automation and hosting capacity upgrades under DER-driven Grid Reinforcement as described in the 2021 GRC testimony. Each program within Automation is tested to determine where the locational expenditures are most cost effective. The locational investments within automation include the following numbered items from the DRP's Grid Modernization Classification Tables:

8. Substation Automation and Common Substation Platform

[58] D.18-03-023, Appendix C, Section D, p. 6.

[59] E-4983, Attachment A, p. 27.

10. Fault Location, Isolation and Service Restoration

11. Remote Fault Indicators

14. Grid Sensors

15. Remote Controlled Switches

17. Relay Replacement

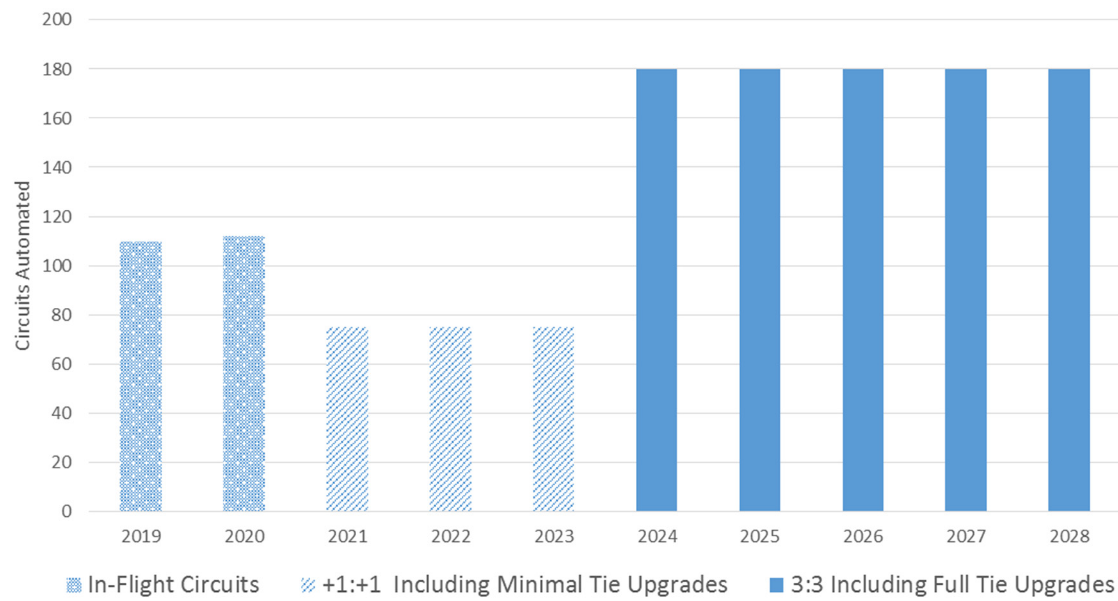
a) <u>Substation Automation and Common Substation Platform (CSP)</u>

DER-driven Substation Automation includes the new SA-3 system and CSP. Each new SA-3 system will include the replacement of 10-20 relays. DER-driven Substation Automation investments that extend beyond the 2021 GRC Test Year are those identified in the DER Grid Reinforcement Study as “high penetration.” “High penetration” includes several factors that, when combined at a particular substation, indicate severe operational impacts due to DER-driven congestion on the breakers, lines, and apparatus connected to the substation. SCE’s proposed investments will address these adverse reliability and asset management issues.

b) <u>Reliability-driven Distribution Automation</u>

Reliability-driven Distribution Automation (R-DA) includes grid sensors, RFIs, RCSs, and intelligent automated switches that facilitate FLISR. These expenditures are driven by the need to improve customer reliability. The locations for these investments are prioritized based on the expected level of reliability benefit, subject to constraints. The 2021 GRC testimony discusses the factors that determine which circuits are selected for R-DA investment, including any Infrastructure Replacement work that is being considered for Worst Circuit Rehabilitation. The modern automated circuits that result from these investments will have enhanced reliability and safety and will be able to host more DERs safely and reliably. SCE plans to deploy one additional midpoint switch and one additional tie switch on approximately 75 circuits annually through the 2023. SCE will then increase the scope to include three midpoint switches and three tie switches on 180 circuits annually through 2028, as show in Figure 4.

Figure 4
Reliability-driven Distribution Automation

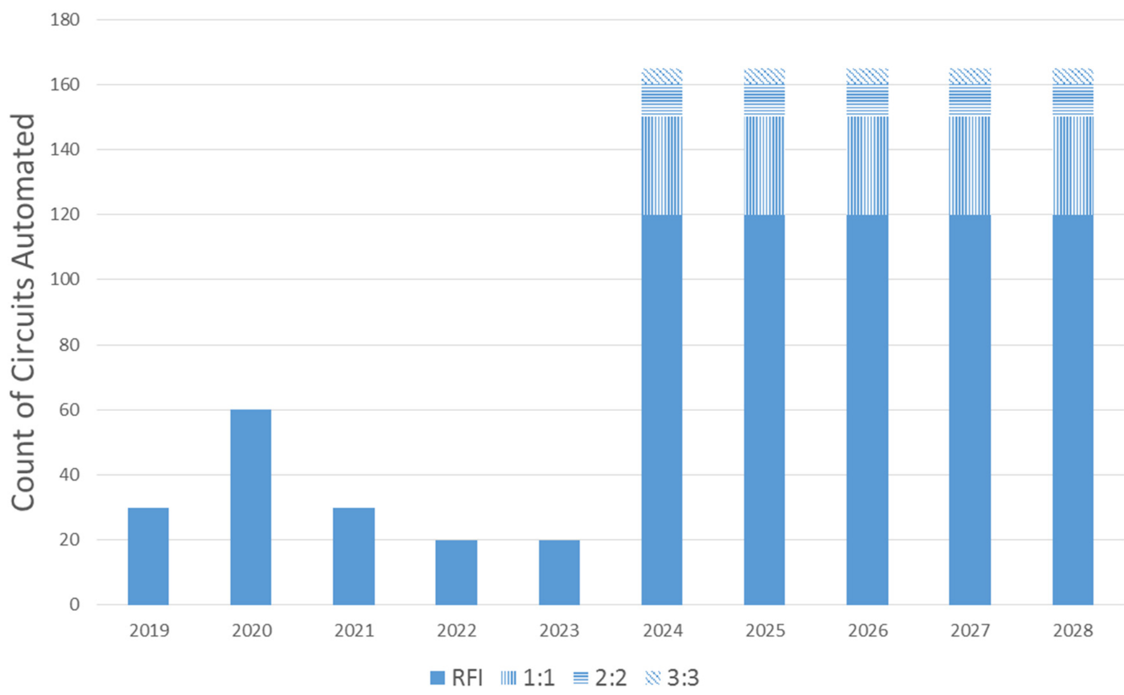


---

c) **DER-driven Distribution Automation**

The need for DER-driven Distribution Automation (D-DA) expenditures is based on: (1) the extent of DER penetration and (2) the corresponding reliability degradation identified by SCE's DER Grid Reinforcement Study. To obtain real-time operating data on circuits already congested with DERs, as discussed in SCE's 2021 GRC testimony, SCE will deploy RFIs on circuits currently/expected to experience operational concerns. During the 2021 GRC period, SCE will monitor the reliability of circuit segments with large quantities of DERs and will use this information to inform further D-DA deployments. SCE believes that additional automation would be prudent now, but has balanced the reliability needs of DER-impacted circuits with SCE's near-term need to emphasize wildfire resilience mitigation. In the future SCE expects to perform additional distribution deployments on high-DER circuits to ensure the reliability of these circuits does not degrade. SCE will likely deploy intelligent automated switches capable of restoring up to 75% of a distribution circuit's customers; without these switches all the customers on the circuit would experience a prolonged outage. Beginning in 2024, SCE plans to increase the number of circuits receiving D-DA from about 20 circuits to 160 circuits annually. Based on the DER management needs of each individual circuit, SCE will deploy either one, two or three midpoint switches (with the same number of circuit tie switches) for each circuit. The annual D-DA deployment scopes are summarized in Figure 5.

Figure 5
DER-driven Distribution Automation



2. <u>DER Hosting Capacity Reinforcement</u>

Grid reinforcements such as DER-driven new circuits and circuit upgrades are triggered by thermal overloads. These overloads are forecasted based on the level of DER penetration (informed by the 2017 IEPR forecast). The upgrades include new or replacement circuits, cables, conductors, equipment, or higher capacity components to mitigate thermal overloads. Figure 6 summarizes SCE's 10-year forecast of the annual DER hosting capacity capital expenditures for the next ten years. SCE forecasts a significant increase in 2021 due to a project backlog accrued while waiting for Commission guidance for the program, which will then level off from until 2024. The forecast for 2024 to 2028 assumes DER adoption is above the 2017 IEPR forecast,[60] which would trigger a disproportionately larger need for additional DER hosting capacity. The forecast applies an additional 35% to account for this uncertainty.

---

[60] This is reflected in the upper range of SCE's 10-year capital forecast.

Figure 6
DER Hosting Capacity Reinforcements