

# Grid Modernization Plan<sup>1</sup>

## 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)<sup>2</sup> — 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”<sup>3</sup> 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;

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<sup>1</sup> 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.

<sup>2</sup> 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.

<sup>3</sup> The grid edge refers to the area of the distribution grid between the customer meter and the distribution substation.

- 1           2. **Customers empowered to choose to be partners** in making the grid more reliable,  
2           efficient and clean; and
- 3           3. **Distribution markets** enabled to maximize the value of DERs and efficiently meet  
4           SCE’s affordability, reliability, and decarbonization goals.

5           This document is SCE’s Grid Modernization Plan (GMP) to implement technologies that  
6 will enable SCE to integrate and optimize DERs while maintaining and improving safety and reliability  
7 and providing other customer benefits. The GMP illustrates the Grid Modernization investments  
8 necessary over a ten-year period and is mindful of the potential impacts of customer and market  
9 behavior on SCE’s distribution system. The GMP transcends merely integrating DERs—it prepares SCE  
10 for the transformation of the entire distribution business, to ensure maximum value for customers and to  
11 achieve ambitious environmental goals.

## 12           **2. Grid Modernization**

13           For most of SCE’s 130-year history, the traditional one-way power flow model of the  
14 distribution grid (where power flows from large central generation stations over transmission networks  
15 and radially to distribution customer loads) has been the norm. Engineering, planning, construction and  
16 operations of the distribution system have been centered on principles of one-way power flow, which  
17 allowed simplified assumptions about the distribution system. Over the last 10 years, as California  
18 implemented public policies to further reduce the environmental impacts of energy consumption, there  
19 has been a dramatic shift to renewable resources and decentralized generation, rapid growth in customer  
20 adoption of DERs, and increasing bi-directional energy flows from DERs connected either behind or in  
21 front of the customer meter. As a result, the traditional one-way power flow model of the distribution  
22 system has been disrupted, and existing planning and operating tools do not provide the visibility and  
23 operational flexibility necessary to address this new operational complexity.

24           As power transactions have increased on the distribution system, so has the complexity  
25 for SCE’s system operators in managing unpredictable bi-directional power flows,<sup>4</sup> masked loads,<sup>5</sup> and  
26 reverse power flows.<sup>6</sup> Looking forward, using the 2017 Integrated Energy Policy Report (IEPR) DER

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<sup>4</sup> Bi-directional power flows can affect voltage control and protection devices.

<sup>5</sup> Masked load is when only the net load of generation and consumption is visible, not the actual load.

<sup>6</sup> “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.

1 forecasts,<sup>7</sup> many of SCE’s distribution feeders will experience reverse power flows due to DERs.<sup>8</sup>  
2 Though DERs are not yet creating major reliability issues for the majority of SCE’s customers, some  
3 wholesale DERs are adversely impacted as SCE’s system operators manage the system based on the  
4 planning and operating tools currently in place. SCE must transform its planning and operations  
5 capabilities to address the increase in DER penetration across the distribution grid.

6 SCE’s GMP includes technologies that will better integrate and optimize DERs, improve  
7 safety, reliability, and wildfire resiliency, and provide the foundation for a clean energy future. Table 1  
8 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

9 Modernizing SCE’s grid planning capabilities is the first step to enabling a clean energy  
10 future. This includes efforts to: (1) transition from a peak-planning process to an hourly profile-based  
11 planning process to help unlock the value of DERs as non-wires alternatives, (2) provide quick and  
12 efficient interconnections through a streamlined business process and publish regularly-updated hosting  
13 capacity values of the distribution system for transparency, development of automated tools and  
14 processes, and more service options, and (3) revise design standards to effectively support new normal  
15 operating conditions resulting from DERs (including building and transportation electrification).

16 Advancing SCE’s ability to actively manage the distribution grid will improve  
17 operational flexibility. SCE will accomplish this by replacing and automating distribution grid  
18 infrastructure (such as switches, sensors, and circuit connections) and introducing the next generation  
19 grid management software solutions. This will provide real-time grid data that improves situational  
20 awareness and increases operational flexibility to control and configure the grid. As a result, operators  
21 will be able to provide faster and more informed responses to grid events and leverage DERs for grid

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<sup>7</sup> Refer to WP SCE-02 Vol.4 Pt. 2, Ch. II – Book A - pp. 14 - 29 – High Distributed Energy Resources Planning Assumptions.

<sup>8</sup> Refer to SCE-02 V.4 Pt. 2–Load Growth for more details.

1 services, which will improve the safety and reliability of the system—despite an ever more complex  
2 distribution grid.

3 SCE needs to upgrade its communication capabilities by expanding its fiber optic  
4 network and transitioning to a low-latency, high-speed wireless field area network. SCE will also  
5 implement advanced grid management systems that will receive and securely analyze real-time  
6 information on customer energy usage, power flows, outages, faults and micro-grid status. The  
7 combination of the communications networks and grid management systems will provide vastly  
8 expanded amounts of data for managing the grid. To use this data effectively, SCE will integrate the  
9 various planning and operations tools to improve planning, operations, outage management,  
10 interconnection, and transparency for customers.

11 By 2028, SCE intends to realize its long-term vision of transforming the grid into a  
12 secure, flexible, networked platform that empowers customers with options to be reliability partners, and  
13 relies on distribution markets to further the goals of safety, reliability, economic efficiency, and  
14 decarbonization. SCE believes a modern utility enables the efficient integration and optimization of  
15 DERs, allows customers to participate seamlessly as grid partners, and plans and operates the grid with  
16 greater precision through enhanced visibility and control.

### 17 **3. Customers as Partners**

18 As increasing numbers of Californians adopt DERs, customers are transforming from  
19 being consumers of electricity to also supplying it to the grid. As stated earlier, customer adoption  
20 of DERs is projected to continue growing rapidly.

21 As SCE implements its GMP, SCE envisions customers empowered as partners in  
22 delivering clean and reliable energy. This will be accomplished by improving customer tools and  
23 continuing to support DER adoption. SCE will:

- 24 • **Provide more appealing programs and services** that will provide customers with  
25 more clean energy choices, enable them to participate in wholesale markets, and  
26 contribute to system reliability
- 27 • **Enable two-way power flows** and advanced coordination of energy sources that  
28 allow customers to seamlessly participate as dynamic partners to provide various grid  
29 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. DER Optimization**

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.<sup>9</sup> 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.<sup>10</sup> 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.

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<sup>9</sup> 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.

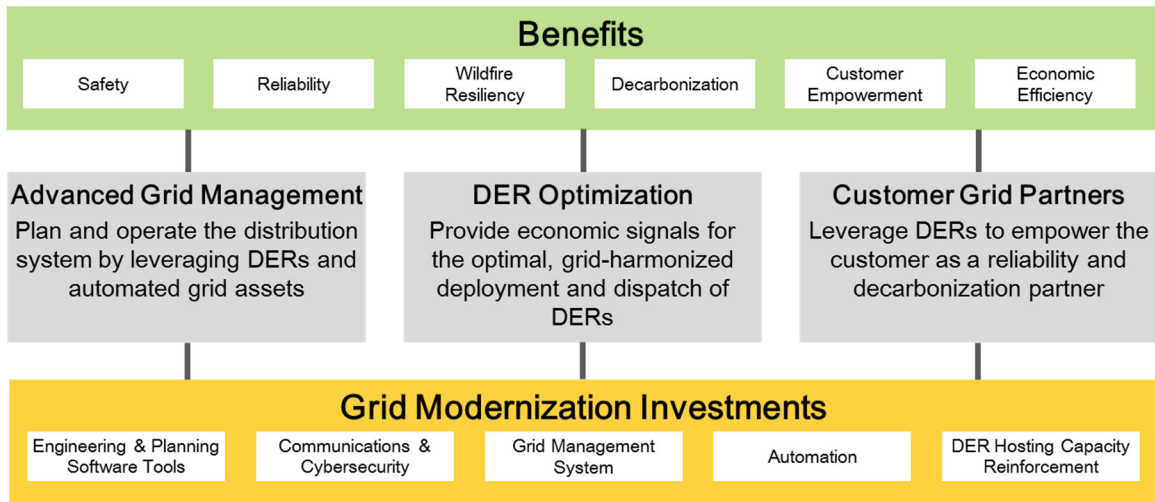
<sup>10</sup> This type of incentive would be an evolution of existing demand side management programs.

1           **5.     Summary**

2           A modernized grid is the foundation of SCE’s 10-year vision for optimizing DER  
3 participation and enabling customers to be reliability partners. Most critically, investments in  
4 technologies will ensure the safe and reliable operation of the grid as DER penetration increases  
5 dramatically. Beyond the operation of the grid, these technologies will make possible the larger goals of  
6 cleaning the power system, enabling customer choice, and maximizing the value of grid and customer  
7 resources. SCE’s Grid Modernization Vision, and a summary of the benefits and investments are  
8 presented in Figure 1.

**Figure 1**  
**SCE’s 10-year Grid Modernization Vision**

SCE’s long-term vision is to transform its distribution grid into a secure, flexible,  
networked platform that optimizes DER value through advanced grid management  
and empowers customers with options to be reliability partners



9           **B.     Changes Necessary to Meet 10-Year DER Growth Forecast**

10           The previous section summarized eight categories of Grid Modernization technologies included  
11 in SCE’s 10-year Grid Modernization vision. Table 2 identifies the technologies included in SCE’s 2021  
12 GRC request for each of the categories and indicates how they align with the technologies in the Grid  
13 Modernization Classification Tables.<sup>11</sup>

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<sup>11</sup> 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
<b>1. Engineering &amp; Planning Software Tools</b>	
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
<b>2. Communications</b>	
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
<b>3. Cybersecurity</b>	Classification Tables identify cybersecurity as a Function of Grid Modernization and Potential System/Integration Challenge, but not as “technology type”
<b>4. Grid Management System</b>	(1) Grid Management System (including ADMS and DERMS), (2) Adaptive Protection System, and (3) Fault Location Isolation System Restoration (software)
<b>5. Automation</b>	
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
<b>6. DER Hosting Capacity Reinforcement</b>	
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	
<b>7. Utility Owned Storage</b>	Utility Owned Storage
<b>8. Microgrid Interfaces</b> (no 2021 GRC request)	Microgrid Interfaces

**1. Grid Modernization Upgrade Status**

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

1 delay in the 2018 GRC decision,<sup>12</sup> while awaiting this decision, SCE prudently invested in key early-  
2 stage implementations of processes and software tools starting in 2016. Consistent with the  
3 Commission's subsequent 2018 GRC decision<sup>13</sup> and the 2018 Distribution Resources Plan (DRP)  
4 decision,<sup>14</sup> SCE's GMP represents its continued commitment to developing new capabilities to engineer,  
5 plan, and operate a modern grid that meets the demands of increasing customer adoption of DERs and  
6 California's policy goals while continuing to provide safe, reliable, and resilient electric service.

7 Each of SCE's Grid Modernization technologies are discussed in detail later in this GMP.  
8 The following excerpts provide a brief summary of the status of SCE's completed and current Grid  
9 Modernization upgrades.

10 a) **Engineering & Planning Software Tool Deployments**

11 SCE initiated planning, analysis and competitive procurement activities for all  
12 five engineering and planning (E&P) software tools in 2015 and 2016, which provided the basis for  
13 SCE's 2018 GRC request. These software tools include:

- 14 1. **Grid Connectivity Model (GCM):** provides an integrated model of SCE's  
15 grid
- 16 2. **Grid Analytics Application (GAA):** provides grid data<sup>15</sup> analytics,  
17 visualization, and decision support capabilities required to plan and operate a  
18 modern grid
- 19 3. **Long-term Planning Tool and System Modeling Tool (LTPT-SMT):**  
20 provides forecasting, power system analysis and work management  
21 capabilities that enhance SCE's long term and short term capacity planning  
22 and Integration Capacity Analysis (ICA) results
- 23 4. **Grid Interconnection Processing Tool (GIPT):** allows customers and SCE  
24 to interconnect generation and load more quickly and efficiently while  
25 improving interconnection process transparency

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<sup>12</sup> 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.

<sup>13</sup> D.19-05-020, pp. 116-118.

<sup>14</sup> D.18-03-023, Ordering Paragraph 7, p. 36.

<sup>15</sup> Includes historical customer meter data and other field measurements.

1                               5. **DRP External Portal (DRPEP):** provides the public with detailed, up-to-date  
2                               information about a circuit’s ability to accept DERs, and opportunities for  
3                               DERs to defer traditional infrastructure investments.<sup>16</sup>

4                               In the fourth quarter of 2016, SCE successfully demonstrated the initial SMT and  
5 DRPEP capabilities, which allowed SCE to calculate ICA values for each distribution circuit and  
6 publish the results to an external SCE portal—as required by the Commission.<sup>17</sup>

7                               SCE’s major accomplishments in 2017 included procuring the LTPT hardware  
8 and product vendor licenses and performing development of the GCM to support the initial releases of  
9 the other E&P tools.

10                              In 2018, SCE enhanced its ability to perform ICA and publish the monthly results  
11 through DRPEP. SCE also enhanced its 10-year system planning and capacity analysis through profile-  
12 based forecasting to support the various DRP analysis and reporting requirements related to the  
13 Distribution Investment Deferral Framework (DIDF) processes.

14                              **b)       Communications and Grid Management System**

15                              In 2016, SCE built a new lab environment, evaluated several field area network  
16 (FAN) vendor products, and completed the common substation platform (CSP) hardware design and  
17 prototype testing.

18                              On the grid management side, SCE has defined a comprehensive solution for  
19 outage and distribution management system. The GMS is a system of systems consisting of Advanced  
20 Distribution Management System (ADMS), DER Management System (DERMS) and advanced  
21 application.<sup>18</sup> In 2018, SCE engaged other large utilities<sup>19</sup> to learn from their GMS deployment  
22 experience and performed a competitive solicitation for its GMS. SCE also developed and implemented  
23 interim control algorithms and DER constraint management functionality until the full DERMS solution  
24 is deployed. SCE limited its spending to these activities (instead of the total program proposed in its  
25 2018 GRC) due to the delay in the GRC decision and potential cost recovery concerns.

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<sup>16</sup> This refers to ICA which the values are updated and published monthly, and the annual GNA and DDOR reports.

<sup>17</sup> See D.18-02-004, OP 2.1 through 2.n, p. 85 in R.14-08-013.

<sup>18</sup> The advanced applications of the GMS are optimization engine, data historian, device management, adaptive protection system, business rule engine and, short-term forecasting engine.

<sup>19</sup> SCE visited Duke Energy, Alabama Power, and Pennsylvania Power & Light (PPL).

1                   c)       **Distribution Automation Deployments**

2                   SCE’s 2018 GRC proposal included a plan to augment automation capabilities on  
 3 its worst performing circuits to improve reliability and help integrate higher amounts of DERs. SCE’s  
 4 plan included fully-automating 200 distribution circuits annually. During 2018 until mid-2019, due to  
 5 the delay in the 2018 GRC decision, SCE moderated the pace of its program. Also, during this time,  
 6 SCE faced severe labor resource constraints due to the concurrent need for wildfire resiliency  
 7 engineering, planning and deployment activities. As the wildfire resiliency activity subsides, SCE plans  
 8 to shift additional labor resources to fully resume the distribution automation deployments.

9                   SCE’s automation deployments have focused on (1) upgrading substations with a  
 10 high risk of relay failures to a modern substation automation design standard (SA-3), and (2) distribution  
 11 automation deployments on circuits with the worst reliability performance. Table 3 summarizes the  
 12 substation automation and distribution automation upgrades that have either been completed or initiated  
 13 to-date.<sup>20</sup>

**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 RFI's	4%	24%	26%	28%	32%	34%
Upgraded Circuit Ties	0%	0%	0%	0%	2%	4%

14                   **2.       Additional Spending Necessary to Achieve GMP Objectives**

15                   Section II. A. provides a ten-year forecast of the capital expenditures necessary to  
 16 achieve SCE’s Grid Modernization vision, including the five-year period (2019-2023) addressed in  
 17 SCE’s 2021 GRC testimony and the subsequent five years (2024-2028). Forecasting the last five years  
 18 of this 10-year period is based on longer-term projections about the rate of DER adoption, the evolution  
 19 of wholesale energy markets, system reliability, and other factors that could influence SCE’s Grid  
 20 Modernization needs. SCE therefore has greater confidence in the five-year GRC forecast than the

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<sup>20</sup> 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.

1 following five years. The following represents an overview of the additional spending SCE anticipates  
2 for each GMP technology area through 2028:

- 3 1. **E&P Software Tools** – Deploy next generation forecasting, capacity planning,  
4 and analytics capabilities to further integrate DERs and Microgrid into SCE’s  
5 system planning processes, and streamline the generation and load  
6 interconnection processes.
- 7 2. **Communications** – Initiate and complete deployment of a new field area  
8 network, complemented with necessary upgrades to SCE’s fiber optic network  
9 and deployment of common substation platform at each distribution substation.
- 10 3. **GMS** – Complete deployment of advanced grid and DER management  
11 applications necessary to support automated switching and DER optimization,  
12 including any necessary market functionalities.
- 13 4. **Automation** – Deploy modern automation on 25% to 50% of SCE’s distribution  
14 circuits.
- 15 5. **DER Hosting Capacity Reinforcement** – Perform the necessary circuit upgrades  
16 to support integration of DERs forecasted in the IEPR DER forecast.
- 17 6. **Cybersecurity** – Continue to refine SCE’s cybersecurity capabilities to keep pace  
18 with evolving cybersecurity threats.
- 19 7. **Microgrid Interfaces** – Perform demonstration projects to evaluate the  
20 technologies and processes necessary to interact with microgrids safely and  
21 efficiently.

### 22 **3. Status of DER-Related Technology Evaluation Projects**

23 To support SCE’s longer term Grid Modernization objective of integrating DERs and  
24 creating opportunities for them to provide grid services, SCE evaluates pre-commercial technologies’  
25 potential to enhance the integration and management of DERs. The Commission’s Electric Program  
26 Investment Charge (EPIC), the Department of Energy (DOE), and other collaborations provide SCE  
27 with opportunities to perform demonstrations of emerging technologies. These activities allow SCE to  
28 test strategies and technologies and provide vendor feedback, prior to full deployment. SCE’s Grid  
29 Modernization testimony provides additional details on SCE’s technology lifecycle management

1 approach.<sup>21</sup> Table 4 provides high-level descriptions and the current status of SCE’s DER-related  
2 projects.

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<sup>21</sup> 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

1 **C. Foundational Technologies**

2 Grid Modernization is intended to accelerate the adoption and integration of renewables and  
3 other sustainable resources on the distribution grid in accordance with California Public Utilities Code  
4 §769.<sup>22</sup> The Commission has defined a modern grid as:

5 A modern grid allows for the integration of distributed energy resources (DERs) while  
6 maintaining and improving safety and reliability. A modern grid facilitates the efficient  
7 integration of DERs into all stages of distribution system planning and grid operations to  
8 fully utilize the capabilities that the resources offer, without undue cost or delay, allowing  
9 markets and customers to more fully realize the value of the resources, to the extent cost-  
10 effective to ratepayers, while ensuring equitable access to the benefits of DERs. A modern  
11 grid achieves safety and reliability of the grid through technology innovation to the extent  
12 that is cost-effective to ratepayers relative to other legacy investments of a less modern  
13 character.<sup>23</sup>

14 SCE has distilled this definition into three primary Grid Modernization functions. A modern grid  
15 should be able to:

- 16 1. Integrate DERs into system planning and grid operations
- 17 2. Enable DERs to fully utilize their capabilities to realize their value
- 18 3. Achieve safety and reliability through technology innovation

19 SCE defines foundational technologies as system-level technologies that are necessary under all  
20 realistic DER-growth scenarios to enable these three functions. The four foundational technologies  
21 include the E&P software tools,<sup>24</sup> communications,<sup>25</sup> cybersecurity, and the grid management system  
22 (GMS). Table 5 summarizes the foundational attributes of these technologies and describes how they  
23 improve upon the capabilities of the traditional solutions.

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<sup>22</sup> 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.

<sup>23</sup> D.18-03-023, p. 7.

<sup>24</sup> 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).

<sup>25</sup> 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. DER-Specific Integration Challenges**

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

1 resolve in order to frame the decision making questions that GRCs need to evaluate.”<sup>26</sup> In response to  
2 D.18-03-023, OP 3, the three investor-owned utilities (IOUs) proposed updates to the Grid  
3 Modernization Classifications Tables, which the Commission approved in Resolution E-4982. Table 6  
4 lists the DER integration challenges identified in the classification tables.<sup>27</sup>

**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	

5 Table 6 summarizes the integration challenges of each DER type,<sup>28</sup> the associated DER control  
6 approach,<sup>29</sup> and the distribution system upgrades necessary to address each challenge. Although this  
7 table identifies the integration challenges, the severity of these challenges is heavily impacted by (1) the  
8 degree of control that SCE or the market have over the DERs, (2) whether or not the focus of control is  
9 location specific (which allows SCE or the market to target specific issues more precisely) or system-  
10 wide (which is less precise), and (3) DER penetration levels and growth rates, which may be affected by  
11 SCE Tariff Rule 21 requirements, State policy incentives (e.g., California Solar Initiative, Self-  
12 Generation Incentive Program, and the Integrated Distributed Energy Resources proceeding), the ability  
13 to bid into wholesale markets at the interconnection (subject to CAISO rules), and DER market prices.

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<sup>26</sup> D.18-03-023, p. 11.

<sup>27</sup> E-4982, Attachment B, pp. 43-45.

<sup>28</sup> Energy Efficiency is excluded since SCE does not foresee it causing any integration challenges.

<sup>29</sup> 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.

1 The mitigations underlined in bold text indicate differences between Table 7 and the Grid Modernization  
2 Classification Tables in Resolution E-4982.<sup>30</sup>

3 As shown in the table, certain integration challenges may more easily be resolved through direct  
4 utility control of the customer resources. One integration challenge, Energy Market Security, is not  
5 included in Table 7. To the extent any DERs participate in wholesale energy markets, this would be a  
6 potential integration challenge. This challenge would be addressed by the GCM, GMS, SA-3 and CSP,  
7 FAN and WAN.

8 SCE's plan for modernizing the grid will mitigate many of these DER integration challenges.  
9 However, SCE's Grid Modernization technologies and capabilities must be complemented by continued  
10 evolution of price incentives that engage DER owners as reliability partners with SCE.

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<sup>30</sup> 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**

DER Type	Control Type	Anticipated DER Integration Challenges	Distribution System Upgrades Critical to Mitigating Each Challenge
Demand Response	Utility-controlled – Global	3. Masked Load 9. Cybersecurity	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
	Utility-controlled – Local	6. Operational Limitations 9. Cybersecurity	
Photovoltaic	Autonomous or Utility-controlled	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	3. GCM, GMS, SA-3 and CSP, FAN, WAN <b>Grid Sensors, RFI</b> s 4. GCM, GMS, LTPT-SMT, DRPEP, GAA, GIPT, SA-3 and CSP, FLISR, RFI, 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, RFI, Grid Sensors, FAN, WAN, RCSs, Utility Owned Storage, Microgrid Interfaces
Photovoltaic with Energy Storage	Autonomous or Utility-controlled	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	7. GCM, GMS, SA-3 and CSP, FLISR, FAN, WAN, Grid Sensors, <b>RFI</b> s 9. GMS, SA-3 and CSP, FLISR, RFI, Grid Sensors, FAN, WAN 10. GMS, SA-3 and CSP, FLISR, RFI, Grid Sensors, FAN, WAN, Utility Owned Storage, Microgrid Interfaces 11. GMS

**Table 7 (cont'd)**  
**DER Integration Challenges and Mitigations**

DER Type	Control Type	Anticipated DER Integration Challenges	Distribution System Upgrades Critical to Mitigating Each Challenge
Energy Storage	Autonomous Utility Controlled (Global & Local)	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	3. GCM, GMS, SA-3 and CSP, FAN, WAN <u>Grid Sensors, RFI</u> s 4. GCM, GMS, LTPT-SMT, DRPEP, GAA, GIPT, SA-3 and CSP, FLISR, RFI, 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, RFI, Grid Sensors, FAN, WAN, RCSs, Utility Owned Storage, Microgrid Interfaces
Electric Vehicles	Autonomous	1. Voltage Fluctuation 2. Steady State Voltage Violations 4. Thermal 5. Protection	7. GCM, GMS, SA-3 and CSP, FLISR, FAN, WAN, Grid Sensors, <u>RFI</u> s 9. GMS, SA-3 and CSP, FLISR, RFI, Grid Sensors, FAN, WAN
	Autonomous or Utility-controlled (with Vehicle to Grid)	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	10. GMS, SA-3 and CSP, FLISR, RFI, Grid Sensors, FAN, WAN, Utility Owned Storage, Microgrid Interfaces 11. GMS
	Utility Controlled – Global & Local (for Demand Response)	3. Masked Load 6. Operational Limitations 9. Cybersecurity	

**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.

- 1 • **Implementing fault location identification and service restoration (FLISR)** schemes that  
2 rely on high speed, device-to-device communications to provide faster outage detection,  
3 response, and recovery. This is particularly important for supporting two-way power flows,  
4 since the operational complexities they create could lead to longer outage durations without  
5 FLISR.
- 6 • **Ensuring that all DER interactions (within a grid with two-way power flows) are cyber-**  
7 **secure** to protect the confidentiality, integrity, and availability of utility and customer  
8 information and systems.
- 9 • **Deploying new grid planning and operations tools** that reduce the challenges two-way  
10 power flows create for system planners, operations engineers and system operators. The  
11 GIPT and DERMS will register, track and manage the DERs while GAA creates the load and  
12 generation profiles to distinguish load from generation.<sup>31</sup> The LTPT-SMT will use these  
13 profiles to perform annual load-profile based analysis to ensure the distribution system can  
14 support the forecasted two-way power flows. The GMS will also introduce advanced  
15 applications to optimize and control the distribution system.

#### 16 **F. DERs as Grid Services Providers**

17 SCE's GMP identifies DER integration challenges, approaches to mitigating the challenges  
18 through distribution system upgrades, and the foundational technologies necessary for DERs to provide  
19 grid services. SCE's analysis of DER alternatives to mitigate DER-integration challenges concluded that  
20 either (1) there are no DER alternatives available or (2) that the distribution system upgrades are also  
21 necessary. Table 8 summarizes the distribution system upgrades and potential DER alternatives  
22 necessary to mitigate each DER-integration challenge. As with Table 7 above, the mitigations  
23 underlined in bold text indicate differences between Table 8 and the Grid Modernization Classification  
24 Tables in Resolution E-4982.<sup>32</sup>

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<sup>31</sup> SCE recognizes that existing tariffs do not allow SCE to control DERs in this manner.

<sup>32</sup> 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 <i>(upgrades needed to enable DER alternatives)</i>
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, <u>Grid Sensors, RFIs</u>	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, <u>RFIs</u>	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 3<sup>rd</sup> party infrastructure to achieve its Grid Modernization objectives when it is possible and reasonable. SCE can leverage existing AMI, 3<sup>rd</sup> 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<sup>33</sup> 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

<sup>33</sup> This includes distribution asset health analytics.

1 the modernized annual distribution planning process.<sup>34</sup> LTPT-SMT also will use the AMI data to  
2 develop forecasts for distribution transformer loading. The GMS will use AMI data for short-term  
3 forecasting, to automatically detect wire-down and high impedance system faults<sup>35</sup>, to improve the  
4 outage restoration process,<sup>36</sup> and to inform Distribution System State Estimation (DSSE).<sup>37</sup>

5 SCE will have the ability to interface with 3rd party communication networks to transact with  
6 DER aggregators. The IEEE 2030.5 communication protocol<sup>38</sup> will facilitate SCE communication with  
7 smart inverters and DER aggregators through the GMS. During the DER interconnection process, the  
8 GIPT will register smart inverters and provide this information to the GMS, which will improve SCE's  
9 ability to monitor and control DERs with smart inverters.

#### 10 **H. Overview of 2021 GRC Grid Modernization Request**

11 Achieving SCE's Grid Modernization vision will require SCE to augment its grid planning and  
12 operations capabilities by deploying an integrated cyber-secure suite of automation, communications  
13 infrastructure, Grid Management System, and electric system forecasting and analytics applications, and  
14 ensuring available capacity to integrate DERs into the electric grid.

15 SCE's recent Grid Modernization efforts and accomplishments have focused on compliance with  
16 DRP decisions that require complex modifications to distribution grid planning and operations. The  
17 DRP proceeding includes three Tracks, of which Track 3 Policy, Sub-track 2 covers Grid  
18 Modernization, and Sub-track 3 covers Distribution Investment Deferral<sup>39</sup> as shown in Figure 2.

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<sup>34</sup> D.17-09-026, Ordering Paragraph 5, pp. 59-60.

<sup>35</sup> 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).

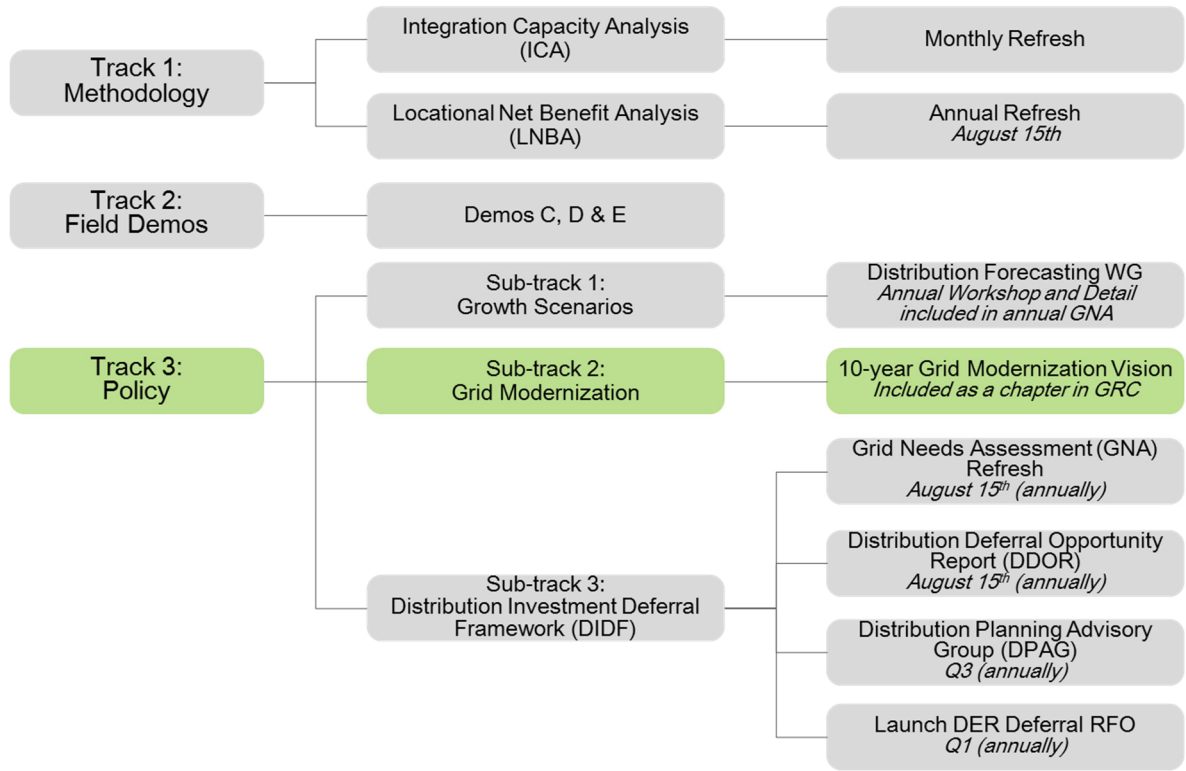
<sup>36</sup> This is to confirm that all customer load has been restored after a system fault.

<sup>37</sup> DSSE uses real-time grid data to estimate load and generation on the distribution system for real-time monitoring and analysis.

<sup>38</sup> IEEE 2030.5 defines the standard protocol used for interacting with smart inverters.

<sup>39</sup> 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***



1 As discussed earlier in this GMP, SCE has developed and implemented short-term software  
 2 enhancements and process improvements to satisfy the Sub-track 3 reporting requirements of the Grid  
 3 Needs Assessment (GNA) and Distribution Deferral Opportunity Report (DDOR). SCE continues to  
 4 investigate the appropriate methodologies to identify location-specific needs across the system. For  
 5 example, D.18-02-004 requires SCE to provide more grid data publicly to facilitate opportunities for  
 6 DERs to defer the need for traditional distribution infrastructure expenditures.<sup>40</sup> In compliance with  
 7 Public Utilities Code Section 769 and commission decisions implementing Section 769 in R.14-08-013  
 8 and acting as a distribution grid operator, SCE will continue transforming its system planning process to  
 9 support expansion of DERs while addressing system reliability and providing net customer benefits.<sup>41</sup>

<sup>40</sup> D.18-02-004, OP 2, pp. 83-89.

<sup>41</sup> See D.17-0-026, D.18-02-004, and D.18-03-023.

1 This includes developing planning tools that enable profile-based analysis<sup>42</sup> of all distribution grid  
2 assets, risk-based distribution portfolio management,<sup>43</sup> and locational net-benefits analysis.<sup>44</sup>

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

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

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<sup>42</sup> 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.

<sup>43</sup> 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.

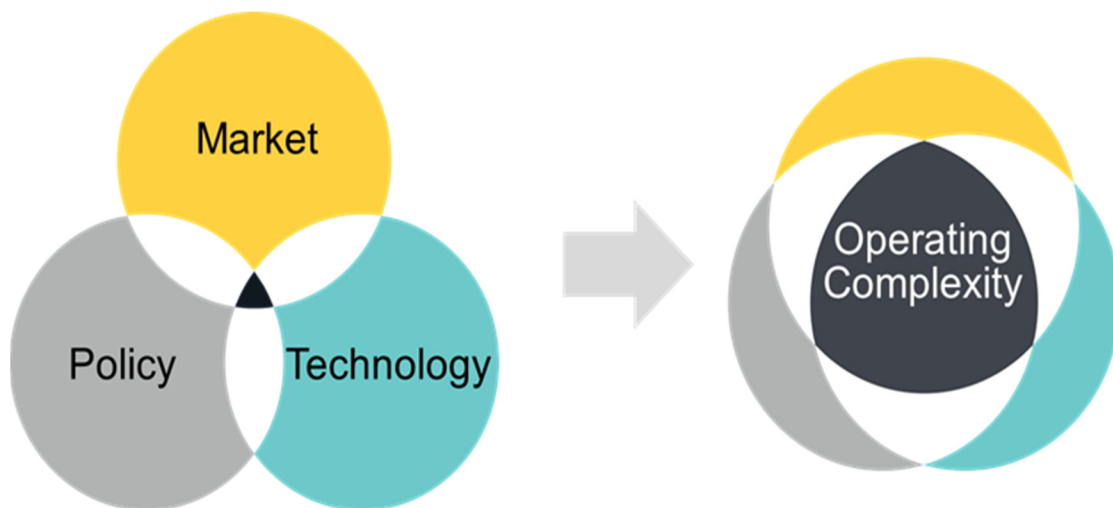
<sup>44</sup> Assembly Bill (AB) 327 of 2013 added section 769 to the California Public Utilities Code, requiring each California Investor Owned Utility (IOU) to submit a DRP proposal "to identify optimal locations for the deployment of distributed resources..." using an evaluation of "locational benefits 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.

1 SCE forecasts \$7.272 million in O&M in Test Year 2021 to manage all Grid Modernization  
2 deployment activities. SCE forecasts \$821.8 million in capital expenditures in 2019 - 2023. This  
3 includes \$120.3 million in engineering and planning software tool investments, \$229.5 million in  
4 automation investments, \$278.1 million in communications investments, \$192.0 million in GMS  
5 investments, and \$2.0 million in DER hosting capacity reinforcement investments.

6 **1. Drivers**

7 Three factors are driving the transformation of the electricity industry: market  
8 developments, state and federal policies, and technology considerations (illustrated in Figure 3). The  
9 acceleration and convergence of these factors is increasing the complexity and difficulty of planning and  
10 operating the distribution grid infrastructure.

*Figure 3  
Convergence of Industry Change Drivers*



11 **a) Market Drivers**

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

1                   **b)       Policy Drivers**

2                   Customer adoption of DERs is also being driven by state and federal policies and  
3 incentives, including California’s Zero-Emission Vehicle (ZEV) program,<sup>45</sup> tax incentives, and  
4 upcoming changes to the Title 24 building standard.<sup>46</sup> The Commission’s DRP proceeding has also  
5 introduced new requirements for integrating DERs into the California investor-owned utilities’  
6 (IOUs’)<sup>47</sup> distribution planning processes.<sup>48</sup>

7                   **c)       Technology Drivers**

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

12                   **d)       Operating Complexity**

13                   New requirements for integrating DERs and technological improvements increase  
14 the complexity and difficulty of planning and operating the grid infrastructure. Challenges can include:  
15 (1) mismatches between peak generation and peak load; (2) masked load, reverse power flows, and  
16 power output fluctuations<sup>49</sup> that challenge grid operators in performing their primary role of maintaining  
17 grid safety and reliability; and (3) exceeding thermal, voltage, and other operating issues on specific  
18 circuit segments—which is often not visible to system operators using existing telemetry and operating  
19 tools.

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<sup>45</sup> 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.

<sup>46</sup> 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.

<sup>47</sup> The IOUs include SCE, Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E).

<sup>48</sup> See D.17-09-026, D.18-02-004, and D.18-03-023 in R.14-08-013.

<sup>49</sup> 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**

GRC Testimony Location		Recorded	2014	2015	2016	2017	2018	2019	2020	Forecast		
		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	
<b>Engineering and Planning Software Tools</b>												
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	
<b>Engineering and Planning Software Tools Total</b>		<b>\$0</b>	<b>\$5,121</b>	<b>\$14,276</b>	<b>\$27,873</b>	<b>\$24,490</b>	<b>\$36,352</b>	<b>\$25,145</b>	<b>\$27,213</b>	<b>\$17,727</b>	<b>\$13,883</b>	
<b>Communications</b>												
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	
<b>Communications Total</b>		<b>\$4,518</b>	<b>\$4,309</b>	<b>\$5,464</b>	<b>\$13,481</b>	<b>\$21,493</b>	<b>\$13,445</b>	<b>\$15,458</b>	<b>\$72,371</b>	<b>\$84,040</b>	<b>\$92,766</b>	
<b>Grid Management System Total</b>	SCE-02 Vol. 4 Pt. 1 - Grid Modernization	<b>\$0</b>	<b>\$0</b>	<b>\$2,274</b>	<b>\$7,851</b>	<b>\$18,726</b>	<b>\$33,064</b>	<b>\$35,724</b>	<b>\$47,611</b>	<b>\$44,864</b>	<b>\$30,682</b>	
<b>Automation</b>												
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					
<b>Automation Total</b>		<b>\$6,090</b>	<b>\$7,763</b>	<b>\$20,321</b>	<b>\$47,990</b>	<b>\$64,081</b>	<b>\$73,398</b>	<b>\$43,032</b>	<b>\$36,044</b>	<b>\$39,411</b>	<b>\$37,617</b>	
<b>DER Hosting Capacity Reinforcement</b>												
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	
<b>DER Hosting Capacity Reinforcement Total</b>		<b>\$0</b>	<b>\$0</b>	<b>\$311</b>	<b>\$1,319</b>	<b>\$863</b>	<b>\$491</b>	<b>\$512</b>	<b>\$44,011</b>	<b>\$22,788</b>	<b>\$27,676</b>	
<b>Cybersecurity</b>	SCE-04 Vol. 3 - Cybersecurity	<b>\$0</b>	<b>\$0</b>	<b>\$2,901</b>	<b>\$14,499</b>	<b>\$21,267</b>	<b>\$25,702</b>	<b>\$24,949</b>	<b>\$45,145</b>	<b>\$28,934</b>	<b>\$36,426</b>	
<b>Energy Storage</b>	SCE-02 Vol. 4 Pt. 1 - Energy Storage	<b>\$3,743</b>	<b>\$3,304</b>	<b>\$733</b>	<b>\$4,125</b>	<b>\$9,270</b>	<b>\$18,615</b>	<b>\$19,290</b>	<b>\$9,516</b>	<b>\$0</b>	<b>\$0</b>	
<b>Microgrid Interfaces</b>	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, improved 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:

- 1       • **Requirement Uncertainty** for the E&P software tool enhancements and GMS in the later  
2       stage of the 10-year deployment.
- 3       • **Contract Timing** for the FAN. Given the timing of the 2018 GRC decision and the  
4       continuing evolution of communications technologies, SCE is continuing to evaluate its  
5       communications options to validate its current deployment approach.
- 6       • **Dynamic Drivers** of automation needs based on reliability performance of individual  
7       circuits, DER adoption rates, and other factors that influence SCE’s automation needs on a  
8       circuit-specific basis. The lower range represents a continuation of adding one midpoint  
9       switch and one tie switch to 75 circuits per year (and only deploying RFIs on the DER-driven  
10      distribution automation circuits), while the higher range includes three midpoint switches and  
11      three tie switches to 75-180 circuits per year (and full automation on the DER-driven  
12      circuits).
- 13      • **DER Adoption Rates** above the 2017 IEPR forecast could trigger the need for additional  
14      DER hosting capacity reinforcement investments. The upper range assumes DER adoption is  
15      above the 2017 IEPR forecast, which would trigger a disproportionately larger need for  
16      additional DER hosting capacity. The forecast applies an additional 35% to account for this  
17      uncertainty.

**Table 11**  
**Grid Modernization 10 Year Capital Expenditure Summary**  
**Recorded 2014-2018/Forecast 2019-2023 (Nominal \$000)**

GRC Testimony Location	Forecast					GMP Lower	GMP Upper
	2019	2020	2021	2022	2023	Range	Range
2024 -2028							
<b>Engineering and Planning Software Tools</b>							
Grid Connectivity Model	\$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
<b>Engineering and Planning Software Tools Total</b>	<b>\$36,352</b>	<b>\$25,145</b>	<b>\$27,213</b>	<b>\$17,727</b>	<b>\$13,883</b>	<b>\$24,000</b>	<b>\$38,000</b>
<b>Communications</b>							
Field Area Network	\$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
<b>Communications Total</b>	<b>\$13,445</b>	<b>\$15,458</b>	<b>\$72,371</b>	<b>\$84,040</b>	<b>\$92,766</b>	<b>\$226,000</b>	<b>\$339,000</b>
<b>Grid Management System Total</b>	<b>\$33,064</b>	<b>\$35,724</b>	<b>\$47,611</b>	<b>\$44,864</b>	<b>\$30,682</b>	<b>\$54,000</b>	<b>\$81,000</b>
<b>Automation</b>							
Reliability-driven Distribution Automation	\$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						
<b>Automation Total</b>	<b>\$73,398</b>	<b>\$43,032</b>	<b>\$36,044</b>	<b>\$39,411</b>	<b>\$37,617</b>	<b>\$245,000</b>	<b>\$970,000</b>
<b>DER Hosting Capacity Reinforcement</b>							
Subtransmission Relay Upgrade Program	\$491	\$0	\$1,488	\$0	\$0	\$0	\$2,000
DER-driven 4 kV Cutovers	\$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
<b>DER Hosting Capacity Reinforcement Total</b>	<b>\$491</b>	<b>\$512</b>	<b>\$44,011</b>	<b>\$22,788</b>	<b>\$14,231</b>	<b>\$160,000</b>	<b>\$295,000</b>
<b>Cybersecurity</b>	<b>\$25,702</b>	<b>\$24,949</b>	<b>\$45,145</b>	<b>\$28,934</b>	<b>\$36,426</b>	<b>\$130,000</b>	<b>\$194,000</b>
<b>Energy Storage</b>	<b>\$18,615</b>	<b>\$19,290</b>	<b>\$9,516</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>
<b>Microgrid Interfaces</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$9,000</b>	<b>\$28,000</b>

\* 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. Investment Capabilities**

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.<sup>50</sup>

<sup>50</sup> 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
<b>Engineering &amp; Planning</b> 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
<b>Communications</b> 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
<b>Grid Management</b> 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
<b>Automation</b> 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
<b>DER Integration Capacity</b> Provides sufficient DER integration capacity to avoid circuit or equipment overloads due to DERs	a. Expanded DER integration capacity	DER Hosting Capacity Reinforcement

1 SCE's proposed Grid Modernization investments address the DER integration challenges  
 2 identified in the Grid Modernization Classification Tables<sup>51</sup> while also enabling Grid Modernization  
 3 functions. Table 13 summarizes the investments, dependencies (other enabling investments must be  
 4 completed prior to the investments), the potential for SCE's proposed Grid Modernization investments  
 5 to mitigate system integration challenges, and functions the investments provide.<sup>52</sup> This summary

<sup>51</sup> Resolution E-4982, Approval of Update to Grid Modernization Classification Tables, Attachment A.

<sup>52</sup> Grid services refers to the "Functions of Grid Modernization" included in E-4982, Attachment B, pp. 38-39.

1 complements the Grid Modernization capabilities in Table 12, which are also discussed in SCE’s Grid  
 2 Modernization testimony.<sup>53</sup>

**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
<b>Engineering &amp; Planning Software Tools</b>			
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
<b>Communications</b>			
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
<b>Cybersecurity</b>	Grid Data Center Infrastructure, FAN, CSP, and WAN	Cybersecurity	Cybersecurity
<b>Grid Management System</b>	Distribution Automation	All 11 integration challenges	All functions except DER Value and Solutions Analysis

<sup>53</sup> 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
<b>Automation</b>			
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
<b>DER Hosting Capacity Reinforcement</b>			
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		
<b>Utility Owned Storage</b>	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
<b>Microgrid Interfaces</b>	GMS (DERMS) and Communications		

1 SCE utilizes a technology lifecycle management approach, which includes testing each  
2 technology in a production environment before it is fully deployed to ensure that it will deliver the  
3 intended capabilities and benefits. Lab and/or field demonstrations allow SCE to confirm not only that  
4 the technologies will operate as intended, but to also gain valuable insight on the most effective  
5 deployment approach to minimize operational risks. Though SCE’s proposed Grid Modernization  
6 technology investments have differing levels of technical maturity and commercialization, each will be  
7 tested through a small scale demonstration (or, for information technologies, extensive testing) prior to

1 full deployment. Table 14 summarizes the maturity of each Grid Modernization technology, the  
 2 expected useful life, and relevant equipment specifications.

**Table 14**  
**Grid Modernization Technology Profiles**

Technology	Maturity	Expected Useful Life	Capacity, Ratings & Other Specifications
<b>Engineering &amp; Planning Software Tools</b>			
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
<b>Communications</b>			
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
<b>Communications (continued)</b>			
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 <b>Adaptive Protection</b> 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
<b>Automation</b>			
Reliability-driven Distribution Automation	<p><b>Fault Location and Service Restoration (FLISR)</b> 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.</p> <p><b>Remote Controlled Switches (RCSs)</b> RCSs are mature technologies with few application limitations. SCE has been retrofitting existing RCSs with Grid Sensors.</p> <p><b>Remote Fault Indicators (RFIs)</b> 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.</p>	15-20 years (switches)	Load Break, Fault Interrupting, Pulse Reclosing
DER-driven Distribution Automation			
		15-20 years	With or Without Grid Sensors and/or Fault Indications
	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	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
DER-driven Substation Automation			
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
<b>DER Hosting Capacity Reinforcement</b>			
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			
<b>Utility Owned Storage</b>	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.
<b>Microgrid Interfaces</b>	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. Investment Justification**

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.<sup>54</sup> Table 15 summarizes the primary investment driver of each Grid Modernization investment (as defined by D.18-03-023<sup>55</sup>), which complement the industry

<sup>54</sup> SCE-02 V.4 Pt. 1, Overview section.

<sup>55</sup> 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

1 change drivers SCE describes in testimony. This table also includes the percentage of the costs  
2 attributable directly to DER integration versus safety and reliability, the DERs that the technology  
3 integrates, and the alternatives that SCE considered in lieu of the proposed investments. The cost  
4 allocations were derived based on a review of the drivers for each workstream.

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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		
<b>Engineering &amp; Planning Software Tools</b>					
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
<b>Communications</b>					
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
<b>Cybersecurity</b>	Maintaining reliability while expanding DER	10%	90%	EV, DG, ES, DR	Available through confidential cybersecurity briefing
<b>Grid Management System</b>	Maintaining reliability while expanding DER	25%	75%	EV, DG, ES, DR	Continue using legacy DMS/OMS
<b>Automation</b>					
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		
<b>Automation (continued)</b>					
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
<b>DER Hosting Capacity Reinforcement</b>					
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
<b>Utility Owned Storage</b>	Supporting targeted distribution deferral with DERs	100%	0%	EV, DG, ES, DR	Traditional grid infrastructure upgrades
<b>Microgrid Interfaces</b>	Maintaining reliability while expanding DER	100%	0%	EV, DG, ES, DR	Traditional grid infrastructure upgrades

**L. Operations and Maintenance (O&M) Expenses**

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	GMP Upper
	2019	2020	2021	2022	2023	Range	Range
						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
<b>Totals</b>	<b>\$5,502</b>	<b>\$11,249</b>	<b>\$19,660</b>	<b>\$17,750</b>	<b>\$21,944</b>	<b>\$90,000</b>	<b>\$163,000</b>

**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
<b>Engineering &amp; Planning Software Tools</b>			
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.	✓
<b>Communications</b>			
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.	
<b>Cybersecurity</b>	✓	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.	✓
<b>Grid Management System</b>	✓	Engaged other large utilities to learn from their ADMS deployments and assess maturity of vendor products, and conducted competitive solicitation.	✓
<b>Automation</b>			
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
<b>Automation (continued)</b>			
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.	
<b>DER Hosting Capacity Reinforcement</b>			
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.	✓
<b>Utility Owned Storage</b>	✓	Three in operation and eight to complete deployment in 2020-2021	✓
<b>Microgrid Interfaces</b>	Not applicable	Not applicable	Not applicable

1 **N. Cost Reasonableness**

2 SCE followed the guidance from the Commission's DRP Track 3, Sub-track 2<sup>56</sup> decision (DRP  
3 Decision) to develop the Grid Modernization investments proposed in its 2021 GRC. The DRP decision  
4 directed the IOUs to use one of two methods to assess investments that improve safety and reliability:  
5 (1) traditional reliability metrics, which the DRP Decision identifies as Option 1; or (2) a lowest cost  
6 approach, which the DRP decision identifies as Option 3.<sup>57</sup> To determine the cost-reasonableness of  
7 investments driven by DER integration, SCE used Option 3.

8 Table 18 summarizes the method used to demonstrate the cost-reasonableness of each proposed  
9 investment.

<sup>56</sup> D.18-03-023.

<sup>57</sup> 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	
<b>Engineering &amp; Planning Software Tools</b>			
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
<b>Communications</b>			
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
<b>Cybersecurity</b>		✓	Available through confidential Cybersecurity briefing
<b>Grid Management System</b>	✓		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	
<b>Automation</b>			
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
<b>DER Hosting Capacity Reinforcement</b>			
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.”<sup>58</sup> SCE investments that meet this definition include the following numbered items from the DRP’s Grid Modernization Classification Tables:<sup>59</sup>

- 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

<sup>58</sup> D.18-03-023, Appendix C, Section D, p. 6.

<sup>59</sup> E-4983, Attachment A, p. 27.

- 1           10. Fault Location, Isolation and Service Restoration
- 2           11. Remote Fault Indicators
- 3           14. Grid Sensors
- 4           15. Remote Controlled Switches
- 5           17. Relay Replacement

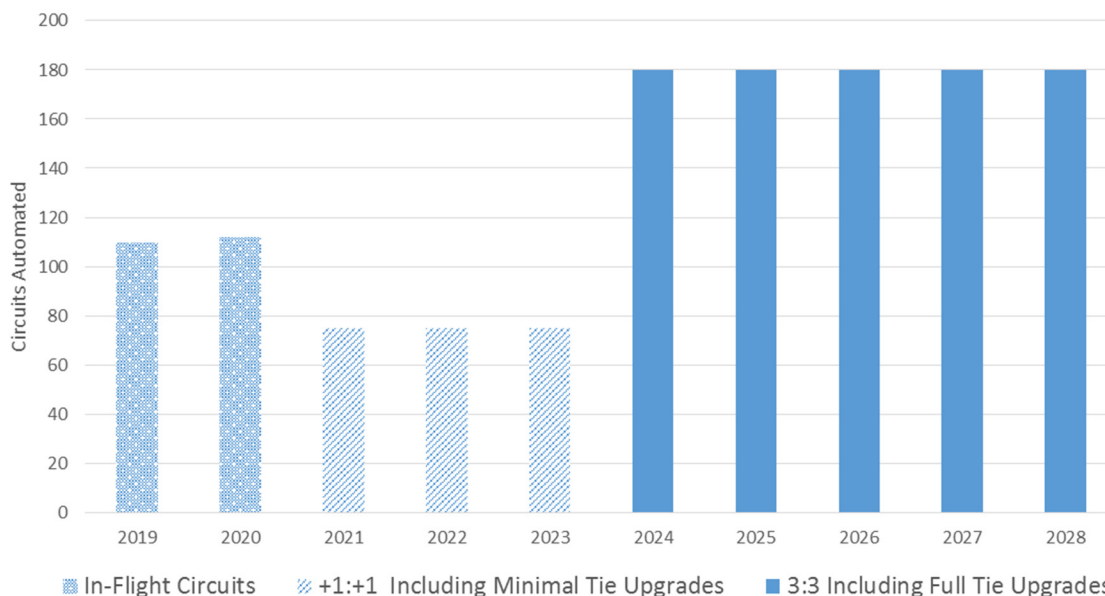
6           **a)       Substation Automation and Common Substation Platform (CSP)**

7                       DER-driven Substation Automation includes the new SA-3 system and CSP. Each  
8 new SA-3 system will include the replacement of 10-20 relays. DER-driven Substation Automation  
9 investments that extend beyond the 2021 GRC Test Year are those identified in the DER Grid  
10 Reinforcement Study as “high penetration.” “High penetration” includes several factors that, when  
11 combined at a particular substation, indicate severe operational impacts due to DER-driven congestion  
12 on the breakers, lines, and apparatus connected to the substation. SCE’s proposed investments will  
13 address these adverse reliability and asset management issues.

14           **b)       Reliability-driven Distribution Automation**

15                       Reliability-driven Distribution Automation (R-DA) includes grid sensors, RFIs,  
16 RCSs, and intelligent automated switches that facilitate FLISR. These expenditures are driven by the  
17 need to improve customer reliability. The locations for these investments are prioritized based on the  
18 expected level of reliability benefit, subject to constraints. The 2021 GRC testimony discusses the  
19 factors that determine which circuits are selected for R-DA investment, including any Infrastructure  
20 Replacement work that is being considered for Worst Circuit Rehabilitation. The modern automated  
21 circuits that result from these investments will have enhanced reliability and safety and will be able to  
22 host more DERs safely and reliably. SCE plans to deploy one additional midpoint switch and one  
23 additional tie switch on approximately 75 circuits annually through the 2023. SCE will then increase the  
24 scope to include three midpoint switches and three tie switches on 180 circuits annually through 2028,  
25 as show in Figure 4.

**Figure 4**  
**Reliability-driven Distribution Automation**

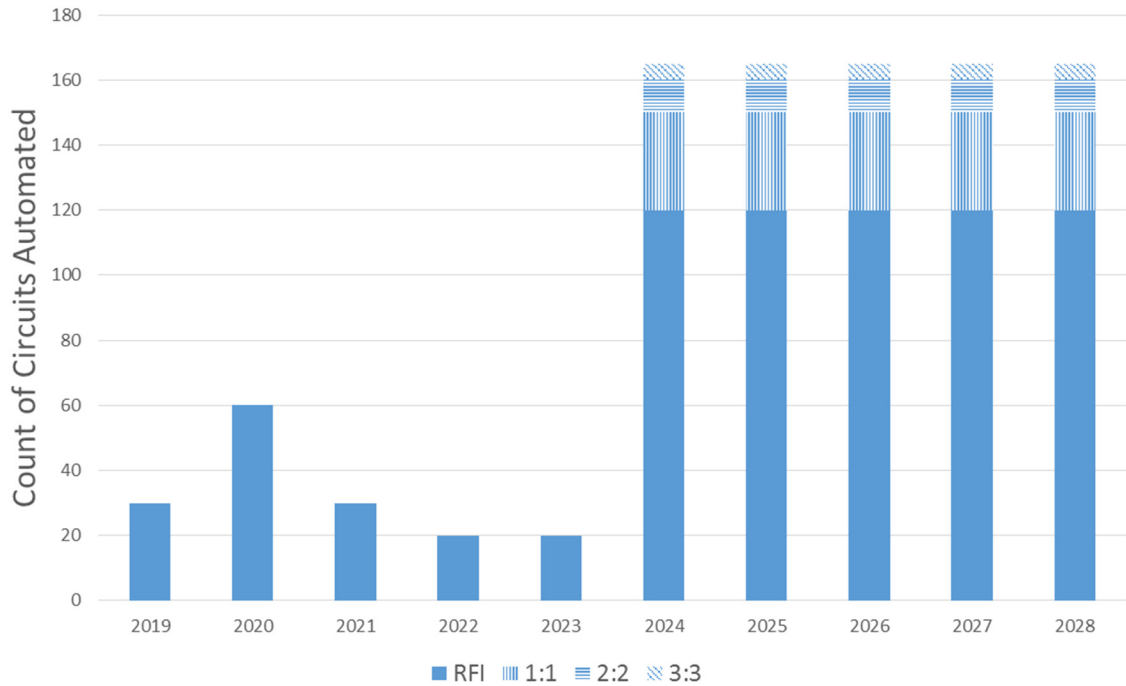


**c) DER-driven Distribution Automation**

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

1 either one, two or three midpoint switches (with the same number of circuit tie switches) for each  
2 circuit. The annual D-DA deployment scopes are summarized in Figure 5.

**Figure 5**  
**DER-driven Distribution Automation**



3 **2. DER Hosting Capacity Reinforcement**

4 Grid reinforcements such as DER-driven new circuits and circuit upgrades are triggered  
5 by thermal overloads. These overloads are forecasted based on the level of DER penetration (informed  
6 by the 2017 IEPR forecast). The upgrades include new or replacement circuits, cables, conductors,  
7 equipment, or higher capacity components to mitigate thermal overloads. Figure 6 summarizes SCE's  
8 10-year forecast of the annual DER hosting capacity capital expenditures for the next ten years. SCE  
9 forecasts a significant increase in 2021 due to a project backlog accrued while waiting for Commission  
10 guidance for the program, which will then level off from until 2024. The forecast for 2024 to 2028  
11 assumes DER adoption is above the 2017 IEPR forecast,<sup>60</sup> which would trigger a disproportionately  
12 larger need for additional DER hosting capacity. The forecast applies an additional 35% to account for  
13 this uncertainty.

<sup>60</sup> This is reflected in the upper range of SCE's 10-year capital forecast.

**Figure 6**  
**DER Hosting Capacity Reinforcements**

