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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.	Rulemaking 14-08-013 (Filed August 14, 2014)
And Related Matters.	Application 15-07-002 Application 15-07-003 Application 15-07-006
(NOT CONSOLIDATED)	
In the Matter of the Application of PacifiCorp (U901E) Setting Forth its Distribution Resource Plan Pursuant to Public Utilities Code Section 769.	Application 15-07-005 (Filed July 1, 2015)
And Related Matters.	Application 15-07-007 Application 15-07-008

ASSIGNED COMMISSIONER'S RULING REQUESTING ANSWERS TO STAKEHOLDER QUESTIONS SET FORTH IN THE ENERGY DIVISION STAFF WHITE PAPER ON GRID MODERNIZATION

Appended to this Assigned Commissioner's Ruling as Attachment A is the Commission's Energy Division, Grid Planning and Reliability Section, Staff White Paper on Grid Modernization (White Paper). Energy Division prepared this White Paper to assist the Commission and the parties in their evaluation of grid modernization investments in this proceeding. The White Paper contains a number of stakeholder questions in the Background, Grid Modernization Investments to Support Distributed Energy Resources, and Process to Evaluate DER-Related Grid Modernization Investments sections therein.

A workshop will be scheduled for June 5, 2017 to discuss the concepts and options presented in this White Paper, and to discuss stakeholder responses to the questions contained in the White Paper.

Stakeholders shall have until June 19, 2017 to serve and file their opening comments, which shall not exceed 30 pages (inclusive of exhibits).

Stakeholders shall have until June 28, 2017 to serve and file their reply comments, which shall not exceed 15 pages (inclusive of exhibits).

In addition to opening and reply comments, stakeholders may also send informal comments and/or recommend topics for discussion in the workshop via e mail to Dina Mackin (dina.mackin@cpuc.ca.gov), Regulatory Analysist, Grid Planning & Reliability, by May 23, 2017.

IT IS SO RULED.

Dated May 16, 2017, at San Francisco, California.

/s/ MICHAEL PICKER
Michael Picker
Assigned Commissioner

[ATTACHMENT]

Staff White Paper on Grid Modernization

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Grid Planning and Reliability Section
Energy Division
California Public Utilities Commission

April 2017

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Terminology and Acronym Glossary

AB: Assembly bill

AC: Alternating current

ADMS: Advanced distribution management system

AMI: Advanced metering infrastructure

BTM: Behind-the-meter

CCA: Community choice aggregator

CEC: California Energy Commission

CPUC: California Public Utilities Commission

CSP: Common substation platform

DC: Direct current

DER: Distributed energy resource(s)

DERMS: Distributed energy resources management system

DMS: Distribution management system

DOE-OE: Department of Energy Office of Electricity Delivery and Energy Reliability

DR: Demand response

DRP: Distribution Resources Plan

DSPx: Next generation distribution system platform, a DOE-OE project

DVVC: Distribution Volt var control

EE: Energy efficiency

ES: Energy storage

ESP: Electric service provider

EV: Electric vehicle

FAN: Field area network

FLISR: Fault location, isolation, and service restoration

GHG: Greenhouse gas

GMP: Grid Modernization Plan

GMS: Grid management system

GNA: Grid Needs Assessment

GRC: General Rate Case

ICA: Integration Capacity Analysis

IDER: Integrated distributed energy resources

IEPR: Integrated Energy Policy Report

IOU: Investor-owned utility

IP: Internet protocol

IRP: Integrated resource planning

LNBA: Locational net benefits analysis

NEM: Net energy metering

PG&E: Pacific Gas and Electric Company

PV: Photovoltaic

SAIDI: System average interruption duration index

SAIFI: System average interruption frequency index

SB: Senate bill

SCADA: Supervisory control and data analysis

SGIP: Self-Generation Incentive Program

SIWG: Smart Inverter Working Group

SCE: Southern California Edison

SDG&E: San Diego Gas & Electric

TOU: Time-of-use

UL: Underwriters Laboratory

VVO: Volt/VAR optimization

WAN: Wide area network

Introduction

The Energy Division of the California Public Utilities Commission (CPUC or the Commission) has prepared this white paper in order to consider how the Commission should evaluate and authorize funding for proposed Grid Modernization investments. Energy Division staff developed this whitepaper based on review of Distribution Resource Plans (DRPs), a public workshop on January 24, 2017, and interviews from utilities, national laboratories, governmental agencies, and industry. This report provides an overview of concepts from those discussions and from literature, and provides a proposed framework for evaluating proposed investments in grid modernization.

California's adoption of its broad set of climate policies to reduce the sources of climate change, including Senate Bill (SB) 350 (Clean Energy and Pollution Reduction Act), Assembly Bill (AB) 32 (California Global Warming Solutions Act), AB 802 (Energy Efficiency), AB 2514 (Energy Storage), Net Energy Metering (NEM), SB 626 (Alternative Fuel Vehicles), and the California Solar Initiative, has brought about widespread adoption and growth of Distributed Energy Resources (DERs). Customers today adopt DERs with expectations that the distribution system will be able to integrate these technologies. The growth of DERs adds a new level of complexity to the planning and function of the distribution grid. The current grid can't respond to the operational conditions that are emerging, requiring new technological upgrades to manage the challenges of grid operations. In response to these new demands, California adopted Assembly Bill (AB) 327 in order to modernize the distribution system to support the state's policy objectives of increasing interconnection of DERs to the distribution system and decreasing greenhouse gas emissions.

This whitepaper proposes a framework to evaluate proposed Grid Modernization investments, in order for the CPUC to direct utilities to make the appropriate investments to enable the growth of DERs while maintaining safety and reliability, with just and reasonable impacts to the ratepayers.

The purpose of this paper is to:

- Inform the development of a framework to evaluate Grid Modernization investments that are primarily aimed at increasing DER penetration, integration, and value maximization;
- Classify grid modernization needs, and the types of investments that can meet these needs;
- Propose a process for authorizing DER-related Grid Modernization investments;
- Discuss the options for integrating a Grid Modernization investment framework into the annual distribution planning cycle and the related General Rate Cases (GRCs); and
- Solicit party feedback to inform the DER-related Grid Modernization Guidance decision.

To develop this whitepaper, CPUC staff held a public workshop in late January 2017. The workshop examined the concepts and issues contained in this paper and invited the IOUs to propose a work plan for the development of a grid modernization planning authorization process.

Staff will request written party comments on textbox questions embedded in this paper. Following receipt of the comments, staff may host an additional public workshop to explore in more detail the options presented for defining a DER-related Grid Modernization framework and process. Next steps are discussed in Section 3.4.

1. Background on the Grid Modernization Vision for CPUC's Distribution Resource Planning Process

AB 327[1] introduced a new framework for utility distribution resource planning and the role DERs[2] will play in achieving the state's ambitious energy and climate goals. Public Utilities (P.U.) Code § 769 requires each IOU to:

- Identify "optimal" locations for the deployment of DERs;
- Submit DRPs that, once approved, must minimize overall system costs and maximize ratepayer benefit from investments in DERs;
- Identify any additional utility spending necessary to integrate cost-effective DERs into distribution planning consistent with the goal of yielding net benefits to ratepayers; and
- Propose any spending on distribution infrastructure necessary to accomplish the DRP in its GRC. Spending may be approved if ratepayers would realize net benefits and costs are just and reasonable.

1.1. DRP Proceeding Background

The Commission issued Rulemaking (R.) 14-08-013 to establish policies, procedures, and rules to guide the California IOUs in developing the Distribution Resource Plans, which were filed on July 1, 2015. An Assigned Commissioner's Guidance Ruling was issued on February 2, 2015, which outlined the Commission's requirements for DRPs that can accomplish the goals of § 769 and move the state towards a high penetration DER future.

The Guidance Ruling directed the utilities to file DRPs to:[3]

- Modernize the electric distribution system to accommodate two-way flows of energy and energy services throughout the IOUs'[4] networks;
- Enable customer choice of new technologies and services that reduce emissions and improve reliability in a cost efficient manner; and
- Animate opportunities for DERs to realize benefits through the provision of grid services.

The Guidance further elaborated key concepts for the DRP process:

[1] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB327.
[2] DERs are defined in P.U. Code § 769 as "renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies."
[3] Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning (Guidance); Issued February 2, 2015.
[4] Pacific Gas and Electric (PG&E), San Diego Gas & Electric (SDG&E), and Southern California Edison (SCE) are the three large investor-owned electric utilities of California.

> An inevitable consequence of these rapidly evolving changes to utility distribution will be the need to add new infrastructure, enhance existing networks and adopt new analytical tools to allow consumers to be active managers of their electricity consumption through the adoption of DERs; the goal being to create a distribution grid that is "plug-and-play" for DERs.

The IOUs filed their DRP applications on July 1, 2015. To review these plans, the Rulemaking was divided into three tracks: (1) Methodological Issues, (2) Demonstration and Pilot Projects, and (3) Policy Issues. The Assigned Commissioner's Ruling on Policy Issues (Track 3 ACR)[5] further divided Track 3 into three sub-tracks: (1) DER Adoption and Distribution Load Forecasting; (2) Grid Modernization Investment Guidance; and (3) Distribution Investment Deferral Process. This paper deals with Sub-track 2–Grid Modernization Investment Guidance. This sub-track will consider the types of Grid Modernization technologies and solutions needed to support the high penetration and value maximization of DERs.

The Assigned Commissioner's Ruling on the Policy Issues[6] described the purpose of Grid Modernization Guidance as addressing the question of "What grid modernization investments are appropriate given the need to integrate the growing number of DERs?" Issues to be considered in the Grid Modernization Guidance sub-track are:

- Identification of distribution grid technologies and/or functions that enable greater DER penetration, integration and value maximization (versus investments that promote visibility, reliability, or resiliency generally);
- Which technologies may be needed on a location-specific basis (whether due to natural adoption or as needed to enable a distribution investment deferral) and which may be needed system-wide; and
- The type of information a utility must provide in order to justify the necessity or cost-effectiveness of a proposed DER-related grid modernization investment.

1.2. Objectives of the DRP Grid Modernization Framework

To further clarify the intent and direct the realization of Grid Modernization within the DRP proceeding, Staff proposes the following guiding objectives:

- Accelerate the adoption of DERs that can cost-effectively provide GHG reductions and provide grid services;

[5] Issued October 21, 2016.

- Connect DERs to existing and new markets to reduce costs and to create value for ratepayers;
- Facilitate the inclusion of DERs into distribution system planning to produce technological, economic and societal benefits; and
- Enhance customer choice and ensure DER-related Grid Modernization investments result in net benefits that are equitably distributed to all ratepayers.

1.3. Defining Grid Modernization for the Distribution Resources Plan Proceeding

Grid Modernization is a concept that has been developed and defined in reports by various entities including government agencies, professional organizations, and utilities across the U.S. and abroad.[7] In the literature referenced in this section, Grid Modernization is often discussed in broad terms and is not limited to DER-related issues. The Department of Energy (DOE) specified key attributes of a modernized grid: it must be reliable, affordable, clean, flexible, and innovative.[8] The modern grid must have greater resilience to hazards of all types; improved reliability for everyday operations; enhanced security from an increasing and evolving number of threats; additional affordability to maintain economic prosperity; superior flexibility to respond to the variability and uncertainty of conditions to one or more timescales, including a range of energy futures; and increased sustainability through additional clean energy and energy-efficient resources.[9]

In its 2018 GRC application, SCE clarified that while some grid modernization investments solely enable DER penetration and some solely support reliability, resiliency and safety, there are many grid modernization investments that serve both purposes.[10]

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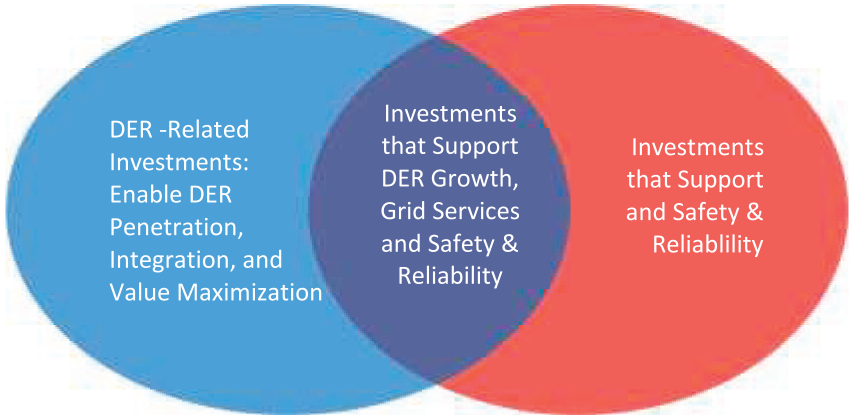
[7] The term "Smart Grid" is also used interchangeably with "Modern Grid" but for the purposes here, a Smart Grid will be considered a subset of a "Modern Grid." As per a "Modern Grid" there are a wide range of definitions for a "smart grid." One paper favors the definition provided by the Smart Grids European Technology Platform: "electricity networks that can intelligently integrate the behavior and actions of all users connected to it—generators, consumers and those that do both—in order to efficiently deliver sustainable, economic and secure electricity supplies." *UK smart grid development: An expert assessment of the benefits, pitfalls and function*. Xenia et. al. Renewable Energy 81 (2015) 89-102.

[8] Office of Electricity Delivery & Energy Reliability Update, February 5, 2015. U.S. Department of Energy.

[9] U.S. Department of Energy (2015) Grid Modernization Multi-Year Program Plan.

[10] A.16-09-001 Application of Southern California Edison General Rate Case

Figure 1: Objectives of Grid Modernization Investments



While Staff recognizes the importance all of the attributes mentioned by other organizations, the DRP proceeding is specifically focused on investments that are primarily driven by the need to accommodate high penetration of DERs (See Figure 1). This includes investments that both enable DER penetration and safety and reliability, but does not include investments made solely for the purpose of safety and reliability. Therefore, Staff proposes the following definition of Grid Modernization for the DRP proceeding in order to further clarify the Commission's objectives, including determining investments that are within scope of the proceeding:

> *A modern grid allows for the seamless interconnection of distributed energy resources while maximizing ratepayer benefits, minimizing impacts and risks of safety and reliability. A modern grid facilitates the efficient integration of these resources into all stages of distribution system planning and operations to fully utilize the capabilities that the resources offer, and enables distributed energy resources to participate in established and emerging markets to more fully realize the value of the resources.*

Distribution investments for traditional maintenance, service area expansion, or reliability, resiliency, and safety unrelated to DERs are out of scope of this proceeding, and can be proposed and authorized through the IOUs' GRCs separate from the Grid Modernization Guidance. Additionally, while Staff recognizes that a modern grid enables DERs to participate in markets, Grid Modernization in this proceeding will focus on the technological investments that would be needed for enabling DERs and not on policy rules that would, for instance, permit DERs to participate in wholesale markets or create distribution level markets.

1.4.Challenges and Opportunities of Distributed Energy Resources

California's policies to encourage DER deployment are fundamentally changing how the electric grid operates. Certain DERs such as energy storage, demand response, and electric vehicles provide capabilities needed for the electric grid on a local level that can help integrate the growing intermittent supply of utility-scale renewables. DERs may serve load, improve power quality and efficiency, enhance outage mitigation, and defer upgrades to the distribution and/or transmission system. However, the rapid adoption of DERs also increases the complexity of the electric system and impacts how the grid is operated. Consequently, grid modernization investments to integrate DERs (e.g., from distribution system management tools to physical infrastructure that accommodates DER penetration) may be required to mitigate these impacts and ultimately realize the benefits of DERs.

With the expansion of DERs, many new technologies have emerged that work to integrate DERs into grid planning and operations. The cost to ratepayers for widespread adoption of all grid modernization technologies could far outstrip the benefits they provide. Meeting the State's climate goals while mitigating ratepayer impacts will require the utilities to focus on making the most of investments to support a cost-effective resource mix and to limit any unnecessary spending. The Commission needs a decision-making framework that will identify the necessary investments to the distribution grid that will yield net ratepayer benefits. Determining net ratepayer benefits will depend on the costs and benefits of alternative GHG free options that are identified in the Integrated Resource Planning Proceeding (IRP), and thus the evaluation of cost-effectiveness of grid modernization will need to be coordinated with the modeling efforts of the IRP proceeding.

Stakeholder Questions:

1. Please provide any comment and/or recommended changes to the definition, challenges and opportunities, or objectives of Grid Modernization presented in this section.
2. Based on the definition above, which investments should be characterized as only supporting safety and reliability, and thus, out of scope of this proceeding?

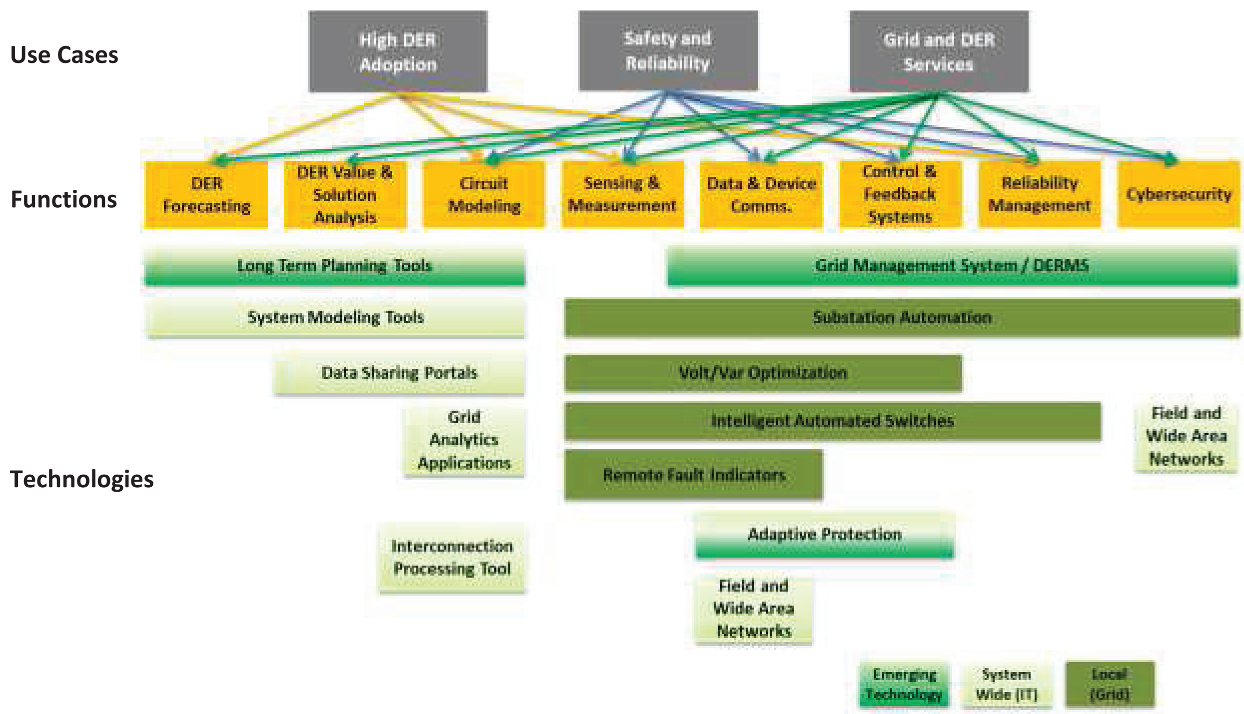
2. Classification of Grid Modernization Investments to Support Distributed Energy Resources

This section examines options for defining the framework to identify and prioritize the grid modernization investments that are necessary to integrate DERs into the grid and maximize their value. To be a useful framework Grid Modernization investments and technologies should be distinguishable from more routine and traditional upgrades to the utility distribution grid. The types of potential grid modernization technologies that the utilities could invest in are diverse, complex, and can serve several different purposes. The Commission needs to understand the function of these technologies and the integration challenges they solve in order to determine whether the costs are just and reasonable and result in net ratepayer benefits. Application of the framework presented in this section will be further considered in Section 3.3.

2.1. Overview of Grid Modernization Framework

At the January 2017 workshop, the IOUs presented a chart showing the relationship between three foundational use cases for grid modernization, eight grid functions, and 13 specific types of technologies. The chart maps which grid functions serve the three use cases and which specific grid modernization technology categories serve each grid function. We found this graphical representation is a good launching point to illustrate the characterization of grid modernization investments.

Figure 2: Use Cases, Functions, and Technologies of Grid Modernization



The literature on grid modernization and stakeholder discussions have revealed that grid modernization investments can be categorized in a number of ways, including by use cases, function, and technology type. It must be stated, however, that many grid modernization investments do not fit neatly into any one of these categories. Many of the investments can serve multiple functions so it may be difficult, or impossible, to evaluate the technologies separately, without regard to their role in the overall grid modernization effort. This complexity necessitates a categorization framework that is flexible and multi-layered in order to understand the interdependencies of certain technology investments, and to understand which investments are necessary to optimize the grid with the growth of DERs.

2.2. Detailed Classifications of Grid Modernization Investments

This section provides more narrative detail for the grid modernization framework presented in Figure 2. In addition to describing the use cases, grid functions, and specific technologies presented in Figure 2, we introduce several additional classification levels to our proposed grid modernization framework. These additional classifications are: whether a grid modernization investment addresses system wide vs, local needs, whether it is a mature vs. emerging technology, and whether it is needed in the short vs long term. Later in Section 2.3 we add two final classifications to our framework: distribution system management activities and a discussion of the operational and integration challenges related to DERs that grid modernization technologies can help manage and mitigate. We put the entire Grid Modernization framework together in Appendix A as an illustration of how grid modernization investment proposals can be presented to the Commission. Appendix A provides a table that identifies how each of these technologies is categorized, which will enable the Commission and parties to better understand the needs and purpose of proposed grid modernization investments. Energy Division seeks input from parties on whether the categories are complete and correctly defined, and how to use them to frame the IOUs' investment proposals.[11]

1. **Grid Modernization Use Cases:** Grid investments may serve multiple use cases or objectives. These use cases are necessary to distinguish in order to identify the drivers of costs and benefits to ratepayers. These use cases are:
   - **High DER Adoption:** Distribution planning is expected to enable the forecasted autonomous growth of DERs that result from existing policies, such as NEM and SGIP, that support these resources. This use case refers to functions and capabilities necessary to safely and reliably accommodate the levels of DER adoption anticipated by California's current policies. This DER growth is driven by customer adoption.
   - **Grid and DER Services:** Locational targeted DERs, such as those being piloted in the Integrated Distributed Energy Resources (IDER) Incentives pilot[12] and considered in the DRP Distribution Investment Deferral Framework (Track 3 Sub-track 3), are expected to provide an alternative to traditional wires solutions by providing capacity, voltage support, and/or enhanced reliability on a circuit. Provisions for grid services require the distribution planning process to identify opportunities for DERs to defer or avoid traditional capital investments. This use case refers to functions and capabilities that are needed to enable grid services provided by DERs to benefit the

[11] These classifications include three illustrated in Figure 2—Use Cases, Functions and Technologies--as well as three additional classifications that Energy Division defines for the Commission's proposed decision making process, which are enumerated in Section 2.3. To manage the overall complexity, this paper does not include the entire list of classification systems presented in DOE's DSPx. Energy Division welcomes input regarding whether the most informative subset of classifications has been applied, or whether to apply others.
[12] Adopted by D.16-12-036.

distribution grid. It also refers to functions and capabilities that are needed to enable DERs to participate in wholesale markets.

- **Safety and Reliability:** This use case refers to functions and capabilities that are needed to provide improved safety and reliability throughout the system, independent of DER growth. Although these investments are needed independent of DER growth, these investments may also provide incremental benefits for enabling higher adoption of DERs. These investments are utility driven.

2. **Distribution System Functions:** Grid modernization technologies can be classified based on their function as part of grid management systems. Examples of technology functions that fall into this category include circuit modeling and reliability management. These functions are further defined in detail in Appendix B.
3. **Distribution System Tools and Technologies:** This list categorizes grid modernization investments by technology type. This is the end-product of this Grid Modernization sub-track: to identify the actual technologies that utilities will invest in. These functions are further defined in detail in Appendix C.
4. **Classifications of Proposed Investments:** Grid Modernization investment needs to be further categorized by the following aspects:

   - **System-Wide v. Localized Investments –** Classify whether the investment serves system-wide needs or location-specific needs.
     - Location-specific investments require a structure to prioritize and define a threshold of just and reasonable costs, as further discussed in Section 3.3.1.
     - System-wide investments are defined by a single technology or modeling platform that supports the entire grid, and is necessary to integrate DERs
   - **Emerging v. Mature Technology:** The determination of whether a proposed investment is a mature or emerging technology may be an important consideration in evaluating proposed investments.
   - **Short v. Medium v. Long-Term Needs:** To evaluate the IOU's proposals, the Commission will need to understand the timing of specific grid needs that proposed investments respond to.

2.3. Other Classifications of Grid Modernization Investments

There have been several other classifications of Grid Modernization technologies, in particular, in DOE's DSPx framework.[13] For the sake of managing complexity, this paper will only present two additional groups of classifications that are necessary for understanding how grid modernization investments serve the distribution system.

2.3.1. Distribution System Management Activities

In addition to the classification of grid modernization investments provided in Figure 2, it is necessary to understand how these investments support three major distribution system management activities: distribution system planning, distribution grid operations, and distribution market operations.[14] We include these three major distribution system management activities primarily to further illustrate how the tools and technologies identified in Appendix C and Figure 2 will be used.

1. **System Planning:** Distribution system planning involves forecasting, analysis and information sharing activities, which requires software and analytic tools needed to conduct modeling and analyses on the distribution grid. System planning leverages increased amounts of granular field data to analyze past, present, and future network models to make accurate decisions about future infrastructure needs and incorporating expected DER performance and ensuing impacts on the grid. Examples include analytic tools that help predict how many DERs will be added to a specific feeder as well as how those DERs perform. Planning technologies offer benefits throughout the system once acquired and are therefore considered system-wide.

2. **Grid Operations:** Grid operations technologies enhance operational capabilities to assess, monitor, analyze, and manage grid resources, including DERs, to enable quick responses to mitigate outages and optimize DERs for customers' and the grid's benefit. Grid operations enhancements provide more granular visibility to system conditions and the ability to reconfigure the distribution grid and dispatch resources. Technologies such as sensing and monitoring can be used to gain visibility into DER performance and the

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[13] The U.S. Department of Energy developed the DSPx project--guidance for the next generation distribution system platform, which has defined grid modernization. More information on DOE's DSPx can be found at http://doe-dspx.org/

[14] DSPx project provided this categorization. SCE similarly proposed that Grid Modernization enables capabilities in three categories needed to realize benefits: 1) Operations; 2) Communications; and 3) Planning. Since communications can be considered a subset of operations, it is Staff's opinion that the DOE DSPx's categorization encompasses the overall make-up of the Distribution System and is more suited because it makes a distinction between planning for a distribution system that will meet the requirements to interconnect a diverse portfolio of DERs, operating the physical grid with those DERs, and enabling and managing markets that provide opportunities for customers to participate and benefit from their DERs.

grid's response to changing conditions. Communications technology can transmit data that allows grid operators to optimize the utilization of assets in real-time. Distribution grid operations technologies encompass both hardware and software. As grid operations hardware has limited effect on the grid at large, they are considered on a location-specific basis. Software, on the other hand, such as for operational forecasting, asset optimization, and distribution system models may be implemented on a regional or system-wide basis.

3. **Market Operations:** Wholesale energy and capacity markets are necessary to monetize the value of DERs in providing bulk system-level services. Market opportunities for DERs to provide services at the distribution level are currently under development, largely within the DRP and IDER proceedings. Market operations technology enables markets to function. It includes technologies that enable market oversight and the sharing of market information as well as those that enable DER sourcing, DER aggregation, and DER portfolio management. The category is primarily software based, and should be considered as a system-wide implementation.

2.3.2. Operational and Integration Challenges Related to DERs

As more DERs interconnect to the distribution system, the impact they have in aggregate on distribution grid operations will become increasingly significant. Energy Division has compiled a preliminary list of potential system/integration challenges presented by high penetrations of DERs and accompanying grid technologies that help mitigate and manage these challenges. While some of these issues may be resolved with smart inverters or other complementary DERs, others may be resolved by planning or technologies that support operations. One of the critical objectives is to distinguish which issues can be solved by smart inverters or complementary DERs and which require Grid Modernization investments. Appendix D provides a table that defines integration challenges and provides examples of technologies that address these challenges. Energy Division seeks input from parties on whether the list is complete.

2.4. How CPUC Will Use the Framework

CPUC staff is seeking stakeholder input on how to use the classification systems as a framework for review and authorization of grid modernization proposals: whether these classifications are complete and useful, and how they should be applied to evaluate proposed investments. Applications of the framework will be more closely examined in Section 3.2.3 on Grid Modernization Proposal Submittals and Section 3.3.2 on Prioritization of Investments.

Stakeholder Questions:

3. Does this classification framework, with the 5 sets of categories, accurately frame grid modernization technologies for the purpose of clarification and evaluation of grid needs?

If not, how could grid modernization proposals be more effectively framed?

4. Are the categories of use cases, technologies, functions and other classification accurate and complete? If not, what should be added or modified?
5. Are the Appendices accurate and complete? If not, what should be added or modified?

3. Process to Evaluate DER-Related Grid Modernization Investments

This section provides a proposed structure for evaluating grid modernization proposals and outlines the issues that the Commission will need to resolve in order to authorize investments in the IOUs' GRCs. Parties' comments on this whitepaper will inform the Grid Modernization Guidance, which will be developed in a Track 3 decision of R.14-08-013. The purpose of the Grid Modernization Guidance is to help the Commission determine what level of spending on distribution infrastructure are necessary to meet the objectives of P.U. Code § 769; specifically, to enable a high penetration DER future while ensuring ratepayers realize net benefits and that costs are just and reasonable. The Guidance aims to help the Commission establish a process that will enable transparent review to ensure that the IOUs identify and make cost-effective Grid Modernization investments necessary to support DER growth that is realistically expected to materialize, while avoiding "gold-plating" the grid with technology that is not necessary for DER integration.

The Grid Modernization Guidance will need to consider and resolve the following issues:

- **Proposed Grid Modernization Planning Process:** What is the general framework that defines the steps, work products, and decision points necessary to authorize funding for DER related grid modernization? A key decision will be defining the boundary between the Distribution Planning Process and the GRC process. In other words, this guidance should delineate which steps occur before the GRC and which occur in the GRC.
- **Options for Commission Review:** How should the proposals be submitted for review, and what is the Commission's process for vetting the proposals before the more formal GRC funding review and authorization process? Should grid modernization proposals be filed every 3 years aligned with the GRC cycle, on a less frequent basis, or as needed when a utility intends to include a request for significant grid modernization investments in its next GRC application? What is the review and authorization timeline?

  Evaluation Criteria for Determining Net Ratepayer Benefit: How do we define standards for realizing net ratepayer benefit from grid modernization investments? How should proposed investments be prioritized to determine the level of investment in grid modernization that meets the standards for being just and reasonable? What upgrades should remain subject to Rule 21?

3.1. Grid Modernization Planning Process

This section outlines the IOU's existing planning process, and Staff's proposal for the grid modernization planning process.

3.1.1. Existing Utility Planning Process

In the Grid Modernization workshop,[15] the IOUs described the existing process for planning distribution grid upgrades. Conducted on an annual basis, it spans 7 to 10 months beginning after the system reaches peak capacity, identifies projected distribution capacity deficiencies, and develops mitigation plans to address projected deficiencies. The current grid planning process is primarily focused on addressing safety and reliability needs for the coming peak season, and DER integration-related investments are primarily implemented on an as-needed basis through the Rule 21 interconnection process.

A. **Develop Assumptions**: To develop the load forecast, the IOUs start with system-level (top-down) load forecasts from the CEC's IEPR and develop a 1-in-10-year temperature-adjusted load forecast down to the Distribution Planning Area based on historical loading, economic indicators, and temperature data. To develop the DER growth forecast, IOUs estimate projected DER growth through interconnection queues, rebates and incentive programs, and the effects of building codes and standards. Existing and future DER interconnections are factored into feeder-level load shapes.

B. **Distribution Planning Assessment:** The IOUs assess what infrastructure upgrades are needed to meet customer demand while operating the grid safely and reliably, and specifically check to see if equipment and the electricity delivered stays within specified limits in both normal and emergency situations.

C. **Distribution Grid Needs:** Based on the performance of the current grid infrastructure, the IOUs ascertain the grid needs, such as those related to the thermal capacity of grid equipment, voltage and power quality issues, and protection requirements. The location, timing, magnitude and size, and likelihood of the projected need are calculated and analyzed. The IOUs then determine the expected timeline of these needs as some investments require years of advanced planning and construction before becoming operational.

[15] Grid Modernization Investment Framework Workshop, January 24, 2017. Workshop materials can be found at http://www.cpuc.ca.gov/General.aspx?id=6442452355

D. **Evaluate Potential Grid Investment Alternatives:** The IOUs identify potential grid investments that satisfy grid needs based on a least-cost, best fit process. Alternatives range from reconfiguring and replacing existing equipment to installing new facilities. Proposed solutions are reviewed by cross functional utility teams to ensure the projects are technically feasible from design to end-of-life.

E. **Implement Preferred Alternative:** The final step of the utility Distribution Planning Process is to implement the preferred alternative through engineering, procurement, construction, and operation. The alternatives chosen from this step are used as assumptions for the following year's planning cycle.

3.1.2. Proposed Grid Modernization Planning Process

The proposed Grid Modernization process aims to align with the IOUs' annual distribution planning process while expanding it to enable public review of proposed investments that meet the objectives of P.U. Code §769. The planning process to authorize DER-enabling grid modernization investments needs to be aligned with the IOUs existing planning process, but Staff's proposal refocuses on how to reach the final outcome of authorization of new spending in the General Rate Case. For this reason, it consolidates certain steps that are internal to the IOUs' planning, as described above, while clarifying what the steps are.

Step 1: Annual DRP Grid-level Scenarios and Assumptions
The first step in the DRP planning process is to develop the modeling of the planning assumptions used to determine grid needs, which has been the objective of Phase I in the DRP proceeding. While the IOUs will continue to use the results of their peak capacity and power flow models that they currently use to plan their grid infrastructure upgrades, they are also working with stakeholders in the DRP proceeding to develop new analyses to inform grid planning. The development of grid-level scenarios and assumptions is nearing completion, and is expected to be adopted in 2017 for use in the IOUs' grid modernization plans for the current cycle of the DRP. We anticipate that these analyses will be updated in the future. Scenarios and assumptions are developed through the following annual analyses:

1. **Growth Scenarios:** In Track 3 of the DRP Rulemaking, the IOUs are developing proposed forecasts of DER growth for application in their distribution planning assumptions. These forecasts are informed by the existing forecasting methodologies used for system planning and IRP.
2. **Integration Capacity Analysis**: Track 1 of the DRP Rulemaking entails the creation of the Integration Capacity Analysis (ICA), which calculates the available load and generation hosting capacity at every circuit node in the IOUs' distribution systems based

on the thermal, steady state voltage, voltage fluctuation, operational flexibility, and protection limits of a given circuit. ICA results represent the incremental DER capacity a given circuit can accommodate before significant grid upgrades are needed.

3. **Locational Net Benefit Analysis:** The second DRP tool under development in Track 1 is the Locational Net Benefits Analysis (LNBA), which identifies the net benefits that DERs can provide at any given location. Examined costs include avoided distribution upgrades, avoided transmission expenditures, and avoided system-level costs such as energy and Resource Adequacy. A relatively high LNBA result indicates that DERs may provide significant value at a given location.

With the results of these three foundational DRP planning tools, the IOUs will present an increasingly clear and granular picture of the grid that answers these questions that will inform and drive their future distribution planning, DER sourcing, and distribution investment:

- How much DER capacity is projected to grow and on which circuits?
- How much additional DER can be accommodated at specific locations without additional upgrades?
- At which locations do DERs have the most value?

Step 2: DRP Annual Grid Needs Assessment
In the second step, the IOUs assess the grid needs, identifying the locations on the grid where integration challenges may occur and where distribution upgrades may be necessary. In the IOUs' existing process, the Grid Needs Assessment is an internal planning activity. For the Grid Modernization framework, Staff proposes that the IOUs submit a public Grid Needs Assessment (GNA) document that identifies infrastructure needs from the substation down to the circuit level. The GNA should cite the Growth Scenarios, ICA, and LNBA as the analytic basis for its findings. This GNA should be a summary document of localized grid needs that provides a transparent basis for evaluating the scale at which grid upgrades are necessary, and to what extent investments can be deferred. The Assessment would inform both Distribution Investment Deferral Framework as well as the Grid Modernization Plans. By applying a unified set of planning assumptions to inform the IOU's distribution grid planning, the GNA would identify the grid needs that could be first met with grid services from DERs, while demonstrating the scale of localized grid modernization investments that are need to accommodate DERs. The Commission staff will need to work with IOUs and stakeholders to determine what information should be included in the Assessment to meet these objectives. The requirements for the Assessment will be further considered in Section 3.3 as well as in the Distribution Investment Deferral Framework White Paper.

Step 3: Grid Modernization Plans
In the third step, the IOUs file a proposal for authorization of grid modernization investments, which staff proposes calling the Grid Modernization Plan (GMP). This Plan may be submitted

prior to or within the IOU's GRC, as is further discussed in the following section. In cases where the GNA identifies needs that can be addressed through grid modernization, the GMP will propose specific Grid Modernization investments that can address these needs. A GMP is periodic, it may submitted every three years so as to coincide with the triennial GRC process, or potentially less frequently. Grid Modernization investments can have a long time horizon, so the GMPs should present a planning vision for grid modernization investments out to 10 years. The GMPs should specify which investments are proposed in the proximate GRC cycle, consistent with Step D of their existing process, where the IOUs identify potential grid investments that satisfy grid needs based on a least-cost, best-fit process. These proposals could potentially be submitted in conjunction with the GNAs, or they may be separate, depending on what the Commission determines to be an appropriate review process and schedule. The Commission will need to provide guidance on what information is necessary to submit as part of the IOUs' GMPs in order to make a determination on just and reasonable investments. This guidance will be informed by considerations discussed below in Section 3.2.

As further discussed in the following section, the Assessment and GMP steps could be performed concurrently or sequentially, but in either case, the Assessment is critical to inform the GMP.

Step 4: Grid Modernization Plan Review

The forth step is the Commission's review of the IOUs' proposals. The Grid Modernization Guidance will need to determine whether the review of Grid Modernization Plans should occur within or in advance of the formal GRC funding authorization process. Considering that the GRC process can take 18-24 months, the review of Grid Modernization Plans should not overly complicate, delay, or create redundancies with grid modernization funding decisions taken in the GRC. The objective in establishing the Commission's review process is to leverage the technical expertise of the DRP stakeholders and staff to support the ability of the Commission to make effective funding authorization decisions in the GRC that are well informed by sound grid planning needs and analytics and consistent with §769 goals. Options for Commission review are described in greater detail below, in Section 3.2.

Step 5: GRC Authorization of Grid Modernization Investments

Final authorization of grid modernization investments will occur in the IOUs' respective GRCs. Since each IOU conducts a GRC once every three years, the Grid Modernization Plan will be approved in separate years for each IOU. The Commission will need to establish the schedule for grid modernization individually for each IOU.

Stakeholder Questions:

6. Are the proposed steps in the grid modernization planning process reasonable and appropriate? If not, what should be modified?

3.2. Identification and Review of Grid Needs

In order to establish the grid modernization review process, the Commission will need to resolve several questions about what information is needed for review, how grid modernization investments will be reviewed, and how often it will be reviewed.

3.2.1. Submission of Grid Needs Assessment for Grid Modernization

The Grid Needs Assessment should inform the Grid Modernization Plan, but the Track 3 decision will need to clarify how these activities are coordinated. The objectives of these activities are to ensure that the proposed grid modernization investments are necessary for integration of DERs, and that the IOUs are pursuing investment deferral opportunities where available. However, the process should not be so onerous that it impedes enabling DER investment. The Commission needs to establish a process that will provide oversight but allow grid modernization to be approved and implemented in time to meet the grid needs. There are a number of questions that need to be considered in order to define the Grid Needs Assessment.

- **What information and level of detail should be included in the Grid Needs Assessment?** The IOUs currently produce a several hundred page engineering document to assess what grid upgrades are needed. The Grid Needs Assessment should provide a summary based on metrics that clarify why certain grid modernization upgrades are needed. Staff seeks input from stakeholders to help identify which criteria and metrics would be used to justify and prioritize grid investments. In order to make the GNAs more manageable for parties and Commission staff, the information in the GNAs could be limited to projects that pass viability screens for deferral by DERs, projects that would increase hosting capacity for autonomous DER growth in high-value areas (see Section 3.2.2 below), and relatively large, non-routine DER-related investments.

- **Does the GNA need to be submitted formally or simply be made available for public review?** The GNAs could be submitted for formal comment either in the DRP or successor proceeding or as advice letters to Energy Division. This would allow parties to vet the GNAs before they inform the deferral and grid modernization processes, but it would require additional time for the Commission or Energy Division to approve the GNAs. Alternatively, the GNAs could be posted for informal public comment but be reviewed more formally in the course of reviewing the Grid Modernization Plans and the distribution deferral filings.

- **When and how does the GNA inform Grid Modernization?** Since the authorization of grid modernization investments would occur in GRCs, which are only filed every three years, it is unclear whether all GNAs need to include information related to grid modernization review. One option would be to require the GNA issued during the year a utility files its GRC to include additional information on proposed investments designed to accommodate autonomous growth and proposed system- or region-wide investments in planning, monitoring, and control technologies. A second option would to have the GNA focus solely on localized investments and direct the GMPs to complement the GNAs with information on system/region-wide needs an assessment of one or more solutions to address them.

Stakeholder Questions:

7. What types of information and level of detail should the IOUs include in the GNA?
8. Should the Grid Needs Assessment be formally filed, or only made available for informal review? If formally filed, what is the appropriate procedural vehicle? (e.g., Advice Letter, Motion, Application)?
9. How can the timing of the GNAs, GMPs, and GRCs be best coordinated? How should the Grid Needs Assessment inform the GMP?

3.2.2. Prioritization of Proposed Location-Specific Investments

The Distribution Resource Planning process needs a schema to provide a standard language for prioritization of location-specific investments. The applications are broad, in addition to prioritization of grid modernization investments, this schema may be applicable to a Grid Needs Assessment, distribution investment deferrals, and proactive grid upgrades to accommodate autonomous DER growth. Energy Division has developed the following schema in order to support these processes, based on the planning analyses in the DRP rulemaking—the Integration Capacity Analysis, Locational Net Benefit Analysis, and growth scenarios. This schema will enable the IOUs to identify optimal locations for DER deployment based on available hosting capacity and estimated net benefits, respectively.

Figure 4: Potential Locational Prioritization based on ICA, LNBA, and DER Growth Forecasts

	Forecasted DER Growth			
	High Penetration		Low Penetration	
ICA / LNBA	High Hosting Capacity	Low Hosting Capacity	High Hosting Capacity	Low Hosting Capacity
High Net Benefits	Location A	Location B	Location C	Location D
Low Net Benefits	Location E	Location F	Location G	Location H

Priority Levels

1	2	3	4	5
High				**Low**

The letters represent areas of the distribution grid, while the coloring scheme represents prioritization for Grid Modernization upgrades. These groupings represent a potential prioritization framework for location-specific grid modernization investments where technologies may be used to increase integration of DERs.

The categories that define the locational prioritization are:

- **Hosting Capacity:** A circuit with relatively lower hosting capacity is a higher priority for grid modernization investments because proactive upgrades would increase that circuit's DER hosting capacity.
- **DER Growth Penetration:** A circuit with a relatively higher forecast of DER penetration is a higher priority because grid modernization investments would increase the safe and reliable operation of the system in light of increased two-way power flows and the operational challenges they entail. Furthermore, the IOUs have found that DER growth tends to cluster in certain locations where there are existing DER installations.
- **Locational Net Benefits:** A circuit with relatively higher locational net benefits, by definition, is a higher priority location.

The IOUs would use such a schema to identify the priority level of a grid need in certain location. The Grid Modernization plans may propose that investments be implemented only for locations that are categorized as priority level 1, for example.

Stakeholder Questions:

10. Is this schema an appropriate method to prioritize locational needs and proposed investments? How should it otherwise be modified, or what would be an alternative approach to identifying locational priorities?

3.3. Grid Modernization Plans

Once grid needs have been identified, the utilities will submit Grid Modernization Plans that describe their proposed investments to address those specific needs as well as any investments intended to enhance visibility of system conditions, enable greater value generation by DERs, or facilitate coordination between the distribution and transmission systems.

3.3.1. Proposed Submission Requirements for Grid Modernization Plans

The Grid Modernization Guidance will direct the IOUs in the submission of their Grid Modernization Plans. This section proposes an outline of the information that should be included in the plans.

Overall Proposal

- Total proposed Grid Modernization Plan costs
- Net ratepayer benefits of the proposed investments
- IOU approach to minimizing ratepayer costs and maximizing benefits

Proposed System Wide Investments

- Projected cost
- Function of the investment
- How do the investments advance integration of DERs?
- How do the investments lower ratepayer costs and increase value?
- Classification of Technology:
    - Use Case
    - Grid Function
    - Technology types
    - Distribution System Management activity
    - Emerging or mature technology
    - Timing of investment: short, medium or long term

Location-specific Investments

- Projected cost
- Locational prioritization: What is the threshold for determining whether the investment is needed at a specific location?
- Alternative investment options: What are alternatives (IOU- or third party-owned) to location-specific investments, what are the pros and cons, and how do these compare financially?
- Same Classification of technology as above.

Stakeholder Questions:

11. Should the Grid Modernization Plans include information on both location-specific and systemwide proposed investments or should they focus on systemwide proposals?
12. What additional or different information should the IOUs submit as part of the Grid Modernization Plans?

3.3.2. Options for Commission Review of Grid Modernization Plans

Commission staff has identified three options for how the Grid Modernization Plans may be submitted, reviewed, and authorized. For purposes of this discussion, these options assume that each utility prepares a GMP every three years, coordinated with the filing of its GRC applications.

Option 1: Grid Modernization Plans are submitted directly and reviewed in the General Rate Case without prior consideration in the DRP proceeding

In the DRP proceeding, the Commission will provide guidance on what types of DER-related Grid Modernization investments should be prioritized, how to examine costs and benefits, and how to evaluate investments. The IOUs use this guidance to prepare Grid Modernization Plans to be submitted, reviewed, and authorized in their next GRC. In this option, the GNA may be included or referenced in the submission of the Grid Modernization Plan. This formal proposal would not be reviewed within the DRP proceeding. While the grid modernization guidance may be updated periodically in the DRP, input on actual grid modernization investment proposals will be conducted in the GRC alone.

Pros: This option simplifies the review processes by integrating grid modernization funding review entirely in the GRC. This option is the most efficient approach (in terms of time) to authorize proposed Grid Modernization investments..

Cons: General Rate Cases are large, complex proceedings with many other areas of focus, and decision makers will have less time and expertise to consider the issues involved in grid modernization. Staff and stakeholders with relevant expertise may advise the GRC participants, but the judges and commissioners assigned to a GRC will nonetheless be responsible for vetting and analyzing Grid Modernization proposals while concurrently evaluating proposed expenditures covering all areas of a utility's infrastructure and operations. The GRC staff may not have the time to effectively consider the issues in grid modernization, given the scope of the GRC. Further, detailed review of grid modernization investment requests may be by-passed if a GRC goes to settlement.

Option 2: Grid Modernization Plans are issued for informal review prior to the GRC application

The Commission may require the IOUs to issue Grid Modernization Plans informally for stakeholder review and feedback in the DRP prior to their formal submission in the GRC applications. This approach could resemble the Procurement Review Group process used for procurement of new resources, allowing Commission staff and stakeholders to review and provide feedback before the IOUs submit their GMPs for funding authorization in the GRC. This option may allow for a more effective vetting of GMPs through a public review process so that the record for GRC authorization is more substantial. However, this process would not result in a Commission decision or resolution, instead, it would simply allow the stakeholders to gather information and provide feedback to the IOUs prior to their GRC authorization request, so that they can effectively participate in the GRC.

Pros: An informal submission and review would enable parties to familiarize themselves with the proposal and solicit technical expertise to evaluate grid needs, as well as enable the IOUs to vet their proposal for reasonableness and modification prior to the official submittal. This option will enable the GRC proceedings to use a more informed record to authorize grid modernization funds.

Cons: An informal submission will create an additional step in the authorization process, which will require additional time between the period that the grid modernization plan is developed and authorization in the GRC.[16]

Option 3: Grid Modernization Plans are submitted formally in the DRP Proceeding with final budget request to be authorized in the GRC

In this approach, the Commission oversees a substantive review of the Grid Modernization Plans in the DRP proceeding, or a separate proceeding similar to the Risk Assessment Mitigation Phase,[17]and formally approves the plans (via Ruling or Decision) prior to the funding authorization process that occurs in the GRC. The IOU would base its GRC Grid Modernization request on the GMP blue print. As conditions change the actual GRC requests could deviate to some degree from the original blue print, but should generally be evaluated against the goals contained in the blue print.

Pros: This approach would maintain and benefit from the technical expertise developed in the DRP proceeding to vet IOUs' Grid Modernization Plans, including the technical feasibility of proposed investments to meet grid needs identified in the GNA and whether such investments would provide net ratepayer benefits. Commission staff and decision makers, as well as the parties reviewing the GRC may not have the resources available to provide a sufficient review of the Grid Modernization Plans. GMPs would be long-term plans and an appropriate vetting process would take place outside of the GRC with the right set of stakeholders. The

[16] Given the expected timing of a decision adopting Grid Modernization guidance, the first GRC in which a pre-filing could be required is PG&E's test year 2020 GRC application, scheduled for filing in September 2018.
[17] See D.14-12-025 *Decision Incorporating a Risk-Based Decision-Making Framework into the Rate Case Plan and Modifying Appendix A of Decision 07-07-004.*

GRC would have a general roadmap for each IOUs' Grid Mod Plans to guide the funding authorizations.

Cons: This approach would add an intermediate decision or other deliverable to the grid modernization planning process, expanding its duration by an additional six months to one year. It may be sufficient for the participants in the DRP proceeding to actively participate in the GRC to in order to engage their technical expertise in the process.

Stakeholder Questions:

13. Which option should be implemented and why? How could these options be modified? Are there other options that should be considered?
14. If you recommend an option that requires the utilities to file GMPs in advance of their GRC applications, how far in advance should the GMPs be filed to allow for adequate review?
15. As an alternative to filing GMPs every three years, should the GMPs provide a more general blueprint of proposed grid investments over a longer timeframe?

3.4. Evaluating the Cost Reasonableness of the Grid Modernization Plans

P.U. Code § 769 states that in the context of utility-filed DRPs, spending on grid modernization "may be approved if ratepayers would realize net benefits and costs are just and reasonable." Without addressing the merits here, SCE's proposed $2 billion investment in grid modernization included in the 2018 GRC is the type of investment that the CPUC Grid Modernization framework is designed to address. This scale of proposed investment requires the appropriate level of scrutiny to ensure that the costs are justifiable in light of the State's legislative requirements. This consideration requires net ratepayer benefits to be defined in the context of P.U. Code § 769.

This paper attempts to establish a framework for evaluating the net rate payer benefits of Grid Modernization plans. Ultimately this framework should serve to guide the GRC funding authorization process.

3.4.1. Definition of "Net Benefits"

The net benefits of grid modernization investments depend on how expansively or restrictively they are defined and what assumptions we make about the drivers of DER adoption. "Net benefits" could be interpreted in the following ways:

- **Support autonomous DER growth:** Under this approach, autonomous growth of DERs is driven by existing state policies, and the objective of P.U. Code § 769 is to require the IOUs to build grid infrastructure to support these policies. Net benefits would therefore be defined as the most cost-effective approach to accommodating projected autonomous DER growth. This interpretation would not be a comprehensive comparison of the costs and benefits of the impact of grid modernization to the energy system, but rather an assessment of the most cost effective approach to enabling DER integration for a given projected growth scenario.
- **Account for full cost and benefits of DER growth:** The Commission may interpret the code to indicate that grid modernization investments should be an added cost to DER investments and should only be pursued if DERs plus grid modernization investments are cost effective relative to alternate options to meeting the State's GHG targets. In this interpretation, the net benefits of grid modernization should be considered as part of an optimized energy portfolio to meet GHG targets, as directed in SB 350 and implemented in the IRP. If there are net costs to ratepayers to enable widespread DER deployment, the Commission may need to determine the level of net costs that are justifiable in order to achieve the State's GHG goals.

3.4.2. Challenges with Quantifying Ratepayer Benefits

Calculating net ratepayer benefits associated with grid modernization spending poses several challenges that will limit the reliability of a net benefit assessment. The challenges with assessing benefits include:

- Certain technologies are dependent on another technology's capabilities for full functionality. As such, the net benefits of each individual investment may be dependent on the costs and benefits of upstream or enabling technological elements.
- Certain technologies may be necessary for DER integration, but their purpose and the benefits of these technologies are to support safety and reliability on the aging distribution system. The ancillary benefits of safety and reliability should be accounted for, rather than counting the costs entirely against the benefits of DER integration
- Net benefits of Grid Modernization investments differ based on the location at which they are installed. For example, utilities deploy voltage regulators at specific locations to resolve localized power quality problems; while the benefits from system-wide technology deployments are more limited at each site.
- Net ratepayer benefits are dependent on a number costs and avoided costs of enabling DERs and alternate supply side options identified in the Integrated Resource Proceeding.

3.4.3. Options for Assessing Net Ratepayer Benefits

Since review of proposed grid modernization investments is currently underway in the SCE 2018 GRC, the Commission will need to assess the reasonableness of its proposal while concurrently developing a framework for assessing net ratepayer benefits on an ongoing basis. These options may apply to the evaluations of investments in the short term in a different way than they apply in the long term.

Existing policies offer examples of several different approaches that could be applied to assess the net benefits of grid modernization. Given the complexity and interconnected nature of grid modernization, it may be necessary to apply a combination of approaches and will depend on how the Commission interprets net benefits. Energy Division is providing a list of options in order to seek party input on an appropriate approach or approaches to meeting the objectives of P.U. Code § 769, in the short and long term.

Option 1: IOUs propose cost/benefit valuation by individual technology

IOUs have existing methods they use to internally assess the benefits of distribution technologies, which they may propose to apply in the Grid Modernization Plans. For instance, in the Smart Grid Pilots,[18] PG&E calculated the net present value of deploying line sensors by measuring the money saved by reducing field patrol times and customer outage minutes. They calculated net benefits for Volt/Var Optimization (VVO) by measuring the reduction in energy usage (in MWh) and reduction in needed capacity resulting from the investment.

The Commission could request that the IOUs provide assessments for individual investment proposals that apply an appropriate methodology based on the characteristics of the technology. The net benefits of certain technologies may be more effectively assessed than others, e.g., if certain technologies enable others, their benefits are shared. Thus, the approaches used by the utilities in the existing process may be useful on a limited basis rather than as a comprehensive assessment of the grid modernization.

Pro: These methodologies already exist, and are being applied in IOUs' internal distribution planning analyses.

Con: The methodologies employed by the IOUs may not be consistent, or applicable to all grid modernization investments. Furthermore, since many of the investments support one another, it would be inaccurate to assess benefits for each investment individually, as they share co-dependencies and thus co-benefits. It may be more effective to allow the IOUs to apply existing cost/benefit methodologies when applicable.

[18] PG&E's Smart Grid Pilots can be found at https://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_4990-E.pdf

Option 2: Develop a cost/benefit methodology for grid modernization

The Commission has adopted cost/benefit methodologies for DERs in various resource-specific proceedings, which are being updated in the IDER proceeding. A comprehensive cost/benefit analysis of grid modernization would need to account for the value that grid modernization provides in supporting DERs, and depend on how the Commission interprets "net benefits," as discussed in Section 3.3. If the Commission were to determine that the net benefits must account for the full costs and benefits of DER growth and integration, it would require a comprehensive cost/benefit analysis to be considered.

Development of a cost/benefit methodology would require an accounting of the costs and benefits of all three applications, or use cases, for grid modernization, as defined in Section 2.2. The use cases that drive grid modernization investment represent different technology functions that create different value streams. The first use case is to enable integration of autonomous growth of DERs, which is likely to be the most significant application of DRP-related grid modernization. The net benefits of the first use case would include the benefits to ratepayers realized by the DERs themselves: distributed generation, energy efficiency, demand response, energy storage, and electric vehicles. Benefits also include the avoided costs of upgrading the grid in a piecemeal manner. The costs and benefits of distribution investment deferrals will also need to be accounted for. Finally, grid modernization investments for DER integration provide the ancillary benefit of improving safety and reliability, which, while not the primary driver of the investment, provides a value stream to ratepayers that should be accounted for. Energy Division staff seeks party input regarding whether the list below is complete.

Figure 3: Preliminary List of Cost and Benefits of Grid Modernization

Use Case	Costs	Benefits
High DER Adoption	-Proposed Grid modernization investment costs -Costs of DER incentives	-System-level benefits of DER growth
Grid & DER Services	-Market costs for DER procurement -Cost of enabling grid mod	-Value of deferred or avoided distribution investment
Safety and reliability*	None: Grid modernization planning does not include investments proposed only for safety and reliability	-Ancillary benefits of grid safety and reliability

Pro: A cost-effectiveness methodology may be the most comprehensive and accurate approach to ensure that the assessment of costs and benefits are complete.

Con: The development and approval of a new cost/benefit methodology would be a complex and time consuming undertaking that is likely require years to develop, which would further delay the DRP proceeding and implementation of P.U. Code § 769. Considering the various challenges associated with assessing ratepayer benefits discussed in the previous section, the complexity of the effort may not yield conclusive results. Therefore, it may be more useful to just conceptually consider the costs and benefits of grid modernization in order to inform the process for evaluating investment proposal, rather than to attempt to quantify all costs and benefits.

Option 3: Apply a least cost/best fit approach to grid modernization

If the Commission determines that the "net ratepayer benefits" of grid modernization should be the most cost-effective approach to achieving the goal of high DER penetration, as discussed in the introduction to Section 3.3, then determining the "least cost/best fit" (LCBF) to meeting these objectives would be an appropriate methodology for evaluating grid modernization investments. The CPUC employs this approach to implement the Renewable Portfolio Standard. To do so, the Commission developed evaluation criteria for determining which proposed projects were the best fit at the lowest cost. This approach could consider the applications and functions that are needed and evaluate alternate technology options to meet those needs.

Pro: This approach could a framework for evaluation of bids that does not require a comprehensive accounting of all net benefits, but would enable the Commission to prioritize investments based on their needs.

Con: This approach does not specifically quantify net ratepayer benefits, and may assume that all functions of grid modernization need to be implemented in order to meet the objectives of § 769. This framework was developed and applied in the Renewable Portfolio Standard, which had specific GWh goals, and the LCBF methodology was used to compare procurement alternatives to meet this goal. In the DRP context, the objective of grid modernizations is less defined and measureable, which may make LCBF more difficult to apply.

Option 4: Assess ratepayer benefits as a sensitivity in the IRP optimization analysis

In the IRP process, Energy Division staff will use capacity expansion modeling to explore different approaches for achieving state policy goals. The capacity expansion modeling will identify optimal combinations of supply-side resources that achieve state goals at least cost under different, fixed assumptions about future conditions and levels of demand. Staff will evaluate multiple scenarios in order to identify a Reference System Plan. The Reference System Plan will then provide guidance to load serving entities (LSEs) including IOUs, CCAs, and ESPs regarding the development of LSE-specific Integrated Resource Plans.

One analysis will compare a scenario involving high DER growth and grid modernization to a scenario that emphasizes large-scale renewables and transmission infrastructure. The relative costs of these two scenarios will provide insight into whether grid modernization investments, together with DER growth, offer an approach to achieving policy goals that is cost-effective relative to other possible approaches. Staff will also examine the effect of a high-DER growth and grid modernization approach on costs across a range of different assumptions about the future. The IRP analysis will help to quantify the system-level value of grid modernization assets. This information should be combined with information about distribution-level DER value as calculated by the LNBA to determine whether grid modernization investments have net benefits in a particular location.

Pro: An IRP sensitivity analysis could provide the Commission with a scale of grid modernization investments that are justifiable as an additional cost to integrate DERs. This analysis is currently part of the modeling scope for IRP, and could thus be feasibly implemented on a limited scale in the 2017-18 timeframe.

Con: There are a number of factors that would not be accounted for in a comprehensive manner; namely, safety and reliability benefits. The Commission runs the risk of taking this analysis as conclusive in the near term, without fully comprehending the full benefits of DER integration as a value stream of grid modernization. Thus, this option should be considered a factor in the evaluation of net benefits rather than as the final result.

Stakeholder Questions:

16. Are there any additional approaches to assessing net benefits that should be considered?
17. Which of the above options should be applied and why?
18. Is the table of costs and benefits in Figure 3 complete and accurate? How could Figure 3 be modified? What cost and benefit information should be provided to the Commission for analysis?

3.5. Next steps

This whitepaper serves as a launching point for the development of the Grid Modernization Guidance, which is expected to be adopted by a decision in the third quarter of 2017. We will schedule a workshop to discuss the options presented in this whitepaper. Meanwhile, SCE's grid modernization proposal is currently under review in its 2018 GRC. Commission staff seeks stakeholder input on how the issues discussed in this paper should inform that application.

Stakeholder Questions:

19. How should the Grid Modernization Guidance inform the SCE GRC?

APPENDIX A: Classification of Grid Modernization Investments

Technology Category[19]	Use Case	Function	System wide or Local investment	Distribution System Management Activities	Examples	System/ Integration Challenges Addressed	SCE 2018 GRC Application Categorization
Long Term Planning Tools	High DER Adoption, Grid and DER Services	DER Forecasting, DER Valuation Solution Analysis, Circuit Modeling	System wide	Distribution Planning	Integrated Load and DER forecasting, solution analysis for capacity/reliability, solution analysis comparing DER to traditional upgrades	Thermal, Operational Limitations	SCE04, Vol 2, Transmission and Distribution Software Projects
System Modeling Tool	High DER Adoption, Safety & Reliability, Grid & DER Services	DER Forecasting, DER Valuation Solution Analysis, Circuit Modeling	System wide	Distribution Planning	Integration Capacity Analysis (ICA)	Sustained voltage violations, thermal, protection	SCE 02, Vol 10, System Modeling Tool
Grid Connectivity Model[20]	High DER Adoption, Safety and Reliability, Grid and DER Services	Circuit modeling, data used for Forecasting and DER Value and Solution Analysis	System Wide	Distribution Planning, Grid Operations, Market Operations	Base data layer for ICA, Load and DER forecasting, state estimation	Items 1 - 8 of list of challenges	SCE04, Vol 2, Transmission and Distribution Software Projects
Data Sharing Portals	High DER Adoption, Safety and Reliability, Grid and DER Services	DER Valuation Solution Analysis, Circuit Modeling	System wide	Distribution Planning	Data Sharing Portal (web interface)	Sustained voltage violations, thermal, protection	SCE 02, Vol 10, DRP External Portal

[19] From Figure 2, list of technologies
[20] Not included in Figure 2

Technology Category[19]	Use Case	Function	System wide or Local investment	Distribution System Management Activities	Examples	System/ Integration Challenges Addressed	SCE 2018 GRC Application Categorization
Grid Analytics Application	High DER Adoption, Safety and Reliability, Grid and DER Services	Circuit/System Modeling	System wide	Distribution Planning Grid Operations	Asset management, sensing and measurement (data), improves quality of asset data to improve distribution planning inputs and operational decisions	Sustained voltage violations, thermal, protection, asset management	SCE04, Vol 2, Transmission and Distribution Software Projects
Interconnection Processing Tool	High DER Adoption, Safety and Reliability, Grid and DER Services	Circuit/System Modeling	System wide	Distribution Planning	Customer facing application to support streamlining the interconnection process, improve distribution planning.	Indirect impact on sustain voltage violations, thermal, protection (interconnection process)	SCE04, Vol 2, Transmission and Distribution Software Projects
Grid Management System / DERMS	High DER Adoption, Safety and Reliability, Grid and DER Services	Sensing & Measurement, Data & Device Commas., Control & Feedback Systems, Reliability Management, Cybersecurity	System wide	Distribution Grid Operations, Market Operations	Distributed Energy Resource Management System (DERMS), Advanced Distribution Management System (ADMS), integrated with outage management and energy management systems	Items 2 - 10 of list of challenges	SCE 02, Vol 10, Grid Management System
Substation Automation and Common Substation Platform (CSP)	High DER Adoption, Safety and Reliability, Grid and DER	Sensing & Measurement, Data & Device Commas., Control & Feedback	Local	Distribution Planning, Grid Operations, Market Operations	SCADA, coordinated distribution device control with DERs, protection, cybersecurity	Items 1 - 10 of list of challenges	SCE 02, Vol 10, Substation Automation and CSP

Technology Category[19]	Use Case	Function	System wide or Local investment	Distribution System Management Activities	Examples	System/ Integration Challenges Addressed	SCE 2018 GRC Application Categorization
	Services	Systems, Reliability Management, Cybersecurity					
Volt Var Optimization	High DER Adoption, Safety and Reliability, Grid and DER Services	Sensing & Measurement, Data & Device Commas., Control & Feedback Systems	Local	Distribution Planning, Grid Operations, Market Operations	Automated programmable capacitor controls, integration with DMS and EMS, future integration with smart inverters	Voltage fluctuation, sustained voltage violations	SCE02, Vol 11, Technology Integration
Intelligent Automated Switches	High DER Adoption, Safety and Reliability, Grid and DER Services	Sensing & Measurement, Data & Device Commas., Control & Feedback Systems, Reliability Management	Local	Distribution Planning, Grid Operations, Market Operations	Remote Intelligent Switches, Augmented Remote Control Switches, Automated Automatic Reclosures	Masking Load, Thermal, Operational Limitations, Fault Location &Service Restoration, Cybersecurity	SCE 02, Vol 10, Distribution Automation
Remote Fault Indicators	High DER Adoption, Safety and Reliability, Grid and DER Services	Sensing & Measurement, Data & Device Commas.	Local	Distribution Planning, Grid Operations, Market Operations	Wireless bi-directional fault indicators	Thermal, Operational Limitations, Cybersecurity	SCE 02, Vol 10, Distribution Automation
Field Area Network	Safety and Reliability; Grid and DER Services	Sensing and Measurement, Data & Device Commas., Cybersecurity	Large Local Areas, eventually system	Distribution Planning, Grid Operations, Market	Wireless radios, routers	Items 1 - 10 of list of challenges	SCE 02, Vol 10, Field Area Network

Technology Category[19]	**Use Case**	**Function**	**System wide or Local investment**	**Distribution System Management Activities**	**Examples**	**System/ Integration Challenges Addressed**	**SCE 2018 GRC Application Categorization**
			wide	Operations			
Wide Area Network	Safety and Reliability; Grid and DER Services	Sensing and Measurement, Data & Device Commas., Cybersecurity	Large Local Areas, eventually system wide	Distribution Planning, Grid Operations, Market Operations	Fiber optic and IP connectivity	Items 1 - 10 of list of challenges	SCE 02, Vol 10, Wide Area Network

APPENDIX B: Functions of Grid Modernization Investments

The section categorizes grid modernization technologies based on their function[21] in distribution system management. These categorizations are defined by the IOUs and informed by the U.S. Department of Energy's DSPx project.[22]

1. **DER Forecasting:** DER forecasts refer to identifying future increases in net electrical power flow influenced by the increase in DERs. As described in DSPx, the operational forecasting software tools assess how the "hidden load" challenge, which is the complication of distinguishing between supply resources (distributed generation and storage) and gross demand, impacts the ability to accurately forecast under various operation conditions. There are various methods to obtain a DER forecast such as, analyzing adoption patterns and reviewing circuit demand changes over time as a result of DERs.

2. **DER Value and Solutions Analysis**: Refers to the analysis of determining the time and locational value of DERs, and the analysis of determining the viability of DERs to defer traditional upgrades to the distribution system. As referenced in DSPx, " The avoided cost of distribution investments form the potential value that may be met by sourcing services from qualified DERs, as well as optimizing the location and timing of DER adoption on the distribution system to eliminate impacts and achieve least cost outcomes."

3. **Circuit Modeling:** Circuit modeling refers to an accurate representation of the distribution circuit topology, asset details, load and DER connections, and electrical connectivity (network configuration) required to run analysis and simulations for distribution planning and grid operations. The actual circuit representation coupled with how the system is connected together (connectivity model) is required.

4. **Sensing and Measurement:** Sensing refers to the data collection from devices that measure, track, and record electrical information such as voltage, current, power, reactive power, frequency, and power factor as examples. Measurement refers to the ability to record, track, and compare data to physical reference points in order to understand to determine the state of any aspect of the electric system.

5. **Data and Device Communications:** Data and device communications refers to the physical infrastructure that serves as the medium to transport what comes to and from devices, and the data refers to various information that is provided by the device and the sensors referenced above.

[21] These are the 8 grid functions in Figure 2 on pg. 11 of this paper.
[22] More information on DOE's DSPx can be found at http://doe-dspx.org/

6. **Control and Feedback Systems:** Refers to the system that result in a change in device state due to the monitoring its output, and comparing the actual output with the desired output. As described in DSPx under Distribution Grid Controls, coordination and control refers to the signaling and mobilization of distribution physical assets and DER providing grid services (directly or through an aggregator) to meet system operational and reliability goals on a dynamic basis. Goals include optimizing distribution system performance, and maximizing DER benefits, while avoiding adverse impacts.

7. **Reliability Management**: Reliability management refers to the use of grid data, processes, systems, and procedures to operate the grid safety and reliably. This enables distribution operators to discover, locate and resolve power outages in an informed, orderly, efficient, and timely manner. Technology in this area include distribution management systems, DERMS, energy management systems, outage management systems, and integrated grid management systems. ”

8. **Cybersecurity:** As referenced in DSPx, "Cybersecurity is the protection of computer systems from theft or damage to the hardware, software or the information on them, as well as from disruption or misdirection of the services they provide. It includes controlling physical access to the hardware, as well as protecting against harm that may come via network access, data and code injection, and due to malpractice by operators, whether intentional, accidental, or due to deviation from secure procedures.”

APPENDIX C: Distribution System Tools and Technologies

This list summarizes the proposed technologies included in Grid Modernization planning. Appendix A provides a table that categorizes these tools and technologies by the other classifications in this section, as well as providing examples of the specific technology investments that are needed. These definitions were developed jointly by the IOUs. These tools and technologies reflect those included in Figure 2 on pg. 11 with one addition: Grid Connectivity Model. Items marked with a "*" indicate tools and technologies that are implemented on a system wide basis. All other tools and technologies are implemented at a local grid level.

1. **Long-Term Planning Tools*:** Software tools that facilitate integrated planning and forecasting over a five-to-ten-year horizon to identify optimal solutions to system planning challenges. Functions of the tools include advanced circuit and substation modeling to support DER integration, power flow and system planning analyses, calculation of load blocks at circuit and substation levels, and capacity planning analyses.

2. **System Modeling Tool*:** Performs accurate and near-real time power-flow analyses of the electric system to provide grid operators with detailed information to ensure that voltage limits, thermal limits, and protection settings continue to be met as DER penetration increases. This tool provides generators with information about upgrade costs associated with interconnection requests.

3. **Data Sharing Portals*:** User-friendly, web-based interface that provides customers with immediate access to available information regarding circuit interconnection capacities, such as the information included in the ICA required by the Commission in the DRP.

4. **Grid Analytics Application*:** Software tool that 1) provides a user interface between engineers, operators, and distribution grid designers in using large data, including smart meter data, weather data, outage data and SCADA data,[23] and 2) enables system planners to perform statistical analyses of data on historical field measurement trends, circuit voltage degradation, line transformer utilization, phase identification, operating circuit violations and accuracy of transformer to meter relationships in order to more accurately plan the system.

5. **Interconnection Processing Tool*:** Single web-based user interface that allows customers to submit interconnection requests for generation, load, and combinations thereof connecting under any interconnection tariffs or connecting as load. When

[23] Supervisory control and data analysis

combined with the other Grid Modernization programs, it allows customers to track the status of their interconnection application, enables the utility to provide more accurate interconnection responses in a shorter time period, and reduces the backlog of interconnection requests.

6. **Grid Management System (GMS) / DERMS*:** An advanced software tool that receives and analyzes real-time information on customer energy usage, power flows, outages, faults and microgrid status. This information is transmitted from smart meters, grid assets (including devices installed as part of the Distribution Automation and Substation Automation programs), and DERs. The GMS may also serve as the interface between operators in the control centers and grid assets and facilitate operations in response to or to prepare for grid events, such as planned and unplanned outages and load/generation transfers. The GMS/DERMS may dispatch and/or control DERs to provide grid services.

7. **Substation Automation and Common Substation Platform (CSP):** Modern Supervisory Control and Data Acquisition (SCADA) to enable remote control and data acquisition from substation equipment (such as circuit breakers, transformers, capacitor banks, and devices measuring current, voltage, and power flow). Substation Automation utilizes an open standards (non-proprietary) design to increase interoperability between systems and devices, allows for component upgrades from multiple vendors, and enables modern cybersecurity. The Common Substation Platform (CSP) is a computing platform (hardware and software) that acts as the communication and control hub between the operations center and all substation equipment and distribution circuit equipment and sensors. It is designed to enable remote data acquisition from circuit devices and provide remote and automatic control over circuit devices.

8. **Volt/Var Optimization:** The Distribution Volt VAR Control (DVVC) Program centralizes control of the field and substation capacitors to coordinate and optimize voltage and VARs across all circuits fed by a substation. Supervisory-controlled distribution substation capacitors and existing standard automated distribution field capacitors on distribution circuits are leveraged to reduce energy consumption, while maintaining overall customer service voltage requirements.

9. **Intelligent Automated Switches:** Augmented remote-controlled switches with sensors to give operators real-time visibility into DER operations and their impacts on system performance such as voltage, current, and power flow. Installation of remote-controlled switches with advanced telemetry capabilities replaces the ongoing deployment of similar devices that lack these capabilities. Sometimes referred to as fault location, isolation, and service restoration (FLISR) technology, these switches and associated automated scheme allow for quick and remote reconfiguration of the distribution system in response to abnormal or emergency situations.

10. **Remote Fault Indicators**: Newer models of remote fault indicators can provide dual benefits of remotely providing two-way power flow data and remote indication of system failure locations, resulting in decreased time to respond to abnormal conditions. The new remote fault indicators monitor current along the distribution line and remotely communicate this information to the Distribution Management System used by utility operators. This provides operators with information about real-time conditions so they may make accurate decisions about necessary actions to maintain system reliability.

11. **Adaptive Protection***: Please fill in per graphic

12. **Field Area Network*:** The Field Area Network (FAN) is the communications system connects distribution substations and automated devices on the distribution system. Components of the FAN include a set of wireless radios and routers that help meet the needs of the future distribution grid and forecast DER connections. FAN supports the equipment and functions for Distribution Automation by allowing the switches and fault indicators to communicate with one another and with the Grid Management System and grid operators. The FAN also provides up-to-date cybersecurity.

13. **Wide Area Network*:** Wide Area Network (WAN) program includes: (1) historical program of installing fiber optic cable interconnecting its substations and control centers to enable real-time data transmission and control functions; and (2) installation of hardware and software to convert the data protocol to an internet-based protocol (IP) in order to transmit data through the FAN and to take advantage of the faster speed of the fiber optic cable.

14. **Grid Connectivity Model*:** The Grid Connectivity Model represents the software model of the complete electrical grid. This model replaces existing disparate and disconnected models and serves as the single centralized source of connectivity data for all assets from bulk generation down to the distribution line transformer level and will promote data consistency, centralization, and maintenance of up-to-date information.

APPENDIX D: Preliminary List of Potential System/Integration Challenges

General Issues	Description	Grid Modernization Functional Group	Technologies to Mitigate Challenge[24]
Voltage Fluctuation[25]	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.	Distribution Grid Operations	Smart Inverters, Load Tap Changers, Voltage Regulators, Capacitors, Communication Systems
Sustained Voltage Violations	Power generation on a circuit increases voltage and power usage decreases voltage. DERs may consequently cause nearby voltages to go above or below set voltage standards, which could damage electrical equipment and impact surrounding customers. This is a particular problem for situations where DER generation exceeds load and produces reverse power flow, which various utility equipment was not built for.	Distribution Grid Operations	Smart Inverters, Load Tap Changers, Voltage Regulators, Capacitors[26], Communication Systems
Masking Load	With DER generation, the utility may only see net load, and may be unaware of the true load on each circuit. In situations where lines may have to be de-energized and then re-energized, such as a fault on the circuit, the utility must manage the true load without the assistance of DERs that have not yet been activated. This is in addition to cold load pick up, which is a situation where certain devices require a spike in load at start up, i.e. induction motors, air conditioners, etc.	Distribution System Planning, Distribution Grid Operations	Automation, Sensors, Grid Management Systems, Communication Systems

[24] Examples are not limited to those procured by utilities.
[25] To deal with voltage issues, utilities have conventionally used voltage regulators, capacitors, and load tap changers. Smart inverters pose a new remedy for managing the voltage concerns and do so at the location of the issues. Smart inverter functionalities, such as the Volt/VAR and fixed power factor functions of the Smart Inverter Working Group's Phase 1 Recommendations, continue to evolve and may become a preferred method for voltage management over traditional approaches in the near future.
[26] Starting in 2011, the California Public Utilities Commission initiated an effort to review and, if necessary, revise the rules and regulations governing the interconnection of generation and storage facilities to the electric distribution systems of the investor-owned utilities also known as Electric Tariff Rule 21. As part of this effort, the CPUC and the California Energy Commission established the Smart Inverter Working Group (SIWG) to take advantage of the rapidly advancing technical capabilities of inverters. Inverters are required by some generating resources to convert the direct current (DC) from the generating resource to the voltage and frequency of the alternating current (AC) distribution system of the IOUs. Phase 1 refers to the first set of recommendations of the SIWG, which were also known as the autonomous functions.

General Issues	Description	Grid Modernization Functional Group	Technologies to Mitigate Challenge[24]
Thermal[27]	Power flow exceeding device ratings due to either forward or reverse power flow. Forward flow stemming from load, and reverse power flow stemming from distributed generation may result in wires and/or transformers exceeding their thermal limits.	Distribution Grid Operations	Substations and Circuits Upgrades, Re-Conductors, Voltage Conversion, local DERMS, Communication Systems
Protection	Protection systems were designed to respond to abnormal conditions when subjected to specified benchmarks. DERs may create coordination problems with other protection devices, thereby producing a safety risk or creating an unintended outage. Also, protection systems were typically designed for traditional one-way power flow, and may not provide the required protection when there is two-way power flow due to power injected from DERs at lower voltage levels.	Distribution System Planning, Distribution Grid Operations	Relays, Grid Management Systems, Automation, Communication Systems
Operational Limitations	Abnormal conditions with or without DERs may create operational flexibility problems in maintaining reliability and/or increase the maintenance of distribution equipment due to operation outside of design parameters, such as load tap changes due to voltage variations or continuous loading of secondary transformers that are intended to have a cooling period overnight.	Distribution System Planning, Distribution Grid Operations	Technology Platforms, Sensors, Automation, Grid Management Systems, DERMS, Communication Systems
Fault Location and Service Restoration	Utilities are already moving toward automated schemes that restore power faster. In a world of increasing DERs and particularly those operated by 3rd party aggregators and customers, these manual or automated processes and schemes need to consider the variation and intermittency of variable resources. Some of these faults may affect larger grid operation, and need to be accounted for in the planning stages.	Distribution System Planning, Distribution Grid Operations	Automation, Technology Platforms Grid Management System, Communication Systems
Security	The market could be manipulated by a participant with sufficient market power.	Distribution Grid Operations, Distribution Market Operations	Technology Platforms, Sensors, Resource Diversity

[27] Technologies that increase the thermal limit of nodes on the system are generally legacy technologies. New substations and circuits, re-conductors, and voltage conversion are all possible. Some DERs may also be used to minimize the potential of reaching the thermal rating of equipment. For instance, energy storage may lower the peak of the net demand on a circuit and allow more distributed generation to interconnect.

General Issues	Description	Grid Modernization Functional Group	Technologies to Mitigate Challenge[24]
Cybersecurity	The proliferation of DERs that communicate with utility systems presents many more opportunities and vulnerability to cyber threats.	Distribution Grid Operations	Technologies that can Enable IP Based Cybersecurity Protocols, CSP, Substation Automation
DER Aggregation Impacts on the Bulk Grid	In a world of increasing DERs and particularly those operated by 3rd party aggregators and customers, the larger grid needs to be able to handle events that occur which could lead to cascading outages and grid blackout. These events need to be mitigated in the planning and operation stages to accommodate the loss inertia in the system due to high inverter based generation and a large installed base of DER which trips off-line due aggressive protection settings.	Distribution System Planning, Distribution Grid Operations	Communication Systems, DERMS, smart inverters, synchronous condensers, static var compensators

APPENDIX E: Distributed Resource Planning Glossary

Alternating current: Electric current which reverses direction at regular intervals or periods. In the United States, this generally occurs at a rate of 60 times per second.

Advanced distribution management system: Software platforms that integrate numerous operational systems, provide automated outage restoration, and optimize distribution grid performance.

Advanced metering infrastructure: Measurement and collection system that includes meters at the customer site, communication networks, and data reception and management systems that make the information available to the service provide. Commonly also called smart meter systems.

Behind-the-meter: When a distributed energy resource is installed on the customer's side of the utility meter.

Community choice aggregation: A program which allows communities to offer procurement service to electric customers within their boundaries.

California Energy Commission: The state agency responsible for forecasting future statewide energy needs, licensing power plants sufficient to meet those needs, promoting energy conservation and efficiency measures, developing renewable and alternative energy resources, and planning for and directing state response to energy emergencies.

California Public Utilities Commission: The state agency responsible for regulating privately owned utilities and securing adequate service to the public at rates that are just and reasonable both to customers and shareholders of the utilities.

Common substation platform: A computing platform (hardware and software) that acts as the communication and control hub between the utility's operations center and all substation equipment and distribution circuit equipment and sensors.

Direct current: Electric current that continuously flows in the same direction.

Distributed energy resource(s): Distributed generation resources, distributed energy storage, demand response, energy efficiency and electric vehicles that are connected to the electric distribution power grid.

Distributed energy resources management system: Software-based solution that increases an operator's real-time visibility into the status of DER, and allows for the heightened level of control and flexibility necessary to optimize DER and distribution grid operation.

Distribution management system: An operational system capable of collecting, organizing, displaying, and analyzing real-time or near real-time electric distribution system information. A DMS can also allow operators to plan and execute complex distribution system operations to increase system efficiency, optimize power flows, and prevent overloads.

Demand response: Customers changing their electricity usage (typically reducing use or shifting use to other times in the day) at certain times in response to economic incentives, price signals, or other conditions.

Distribution Resources Plan: A California Public Utilities Commission proceeding which examines proposals filed by the three large California investor-owned utilities per Public Utilities Code § 769 to develop new tools, process, and investment frameworks that enable the utilities to better integrate distributed energy resources into grid operations and the annual distribution planning process.

Distribution Volt var control: A centralized approach for controlling field and substation capacitors to coordinate and optimize voltage and reactive power across all circuits fed by a substation.

Electric service provider: A non-utility entity that offers electric service to customers within the service territory of an electric utility.

Field area network: A communications system that connects distribution substations and automated devices on the distribution system. Components of the FAN include a set of wireless radios and routers that help meet the needs of the future distribution grid and forecast distributed energy resource connections.

Fault location, isolation, and service restoration: The automatic sectionalizing, restoration and reconfiguration of circuits. These applications accomplish distribution automation operations by coordinating operations of field devices, software, and dedicated communications networks to automatically determine the location of a fault, and rapidly reconfigure the flow of electricity so that some or all customers can avoid experiencing outages.

Greenhouse gas: Any gas that absorbs infrared radiation in the atmosphere. Greenhouse gases include water vapor, carbon dioxide, methane, nitrous oxide, halogenated fluorocarbons, ozone, perfluorinated carbons, and hydrofluorocarbons.

Grid management system: An advanced software tool that receives and analyzes real-time information on customer energy usage, power flows, outages, faults and microgrid status.

General Rate Case: A proceeding used to address the costs to operate and maintain the utility system and the allocation of the costs among customer classes.

Integration Capacity Analysis: An analytical tool that determines available grid capacity for distributed energy resources on every circuit in the three large California investor-owned utilities service territories without significant distribution upgrades.

Integrated distributed energy resources: A California Public Utilities Commission proceeding with the intent to integrate these resources and technologies in order to reduce greenhouse gas emissions and increase ratepayer benefits by displacing planned traditional capital investments in "wires" solutions.

Integrated Energy Policy Report: Assessments and forecasts by the California Energy Commission to develop energy policies that conserve resources, protect the environment, ensure energy reliability, enhance the state's economy, and protect public health and safety.

Integrated resource planning: A California Public Utilities Commission proceeding pursuant to Senate Bill 350 which requires the Commission to focus energy procurement decisions on reducing greenhouse gas emissions by 40 percent by 2030, including efforts to achieve at least 50 percent renewable energy procurement, doubling energy efficiency, and promoting transportation electrification.

Investor-owned utility: A private company that provides a utility, such as water, natural gas or electricity, to a specific service area.

Locational net benefits analysis: An analytical tool that identifies the optimal locations for the deployment of distributed energy resources to maximize distribution and ratepayer benefits.

Net energy metering: A billing arrangement that provides credit to customers with solar photovoltaic systems for the energy they add to the grid.

System average interruption duration index: A reliability indicator that is calculated by taking the sum of all customer interruption durations and dividing by the total number of customers served.

System average interruption frequency index: A reliability indicator that is calculated by taking the total number of customer interruptions and dividing by the total number of customers served.

Supervisory control and data acquisition: An industrial computer system that monitors and controls a process. In the electricity sector, SCADA is used to monitor substations, transformers, and other electrical assets.

Self-Generation Incentive Program: A California Public Utilities Commission program which provides incentives to support existing, new, and emerging distributed energy resources by providing rebates for qualified systems installed on the customer's side of the utility meter.

Smart Inverter Working Group: A technical group established by the California Public Utilities Commission and the California Energy Commission that coordinates the development of advanced inverter functionality to mitigate the impact and increase the value of distributed energy resources.

Time-of-use: The pricing of electricity based on the estimated cost of electricity during a particular time block.

Underwriters Laboratory: A world-renowned independent product safety testing and certification organization which develops standards, inspects, advises, tests, and certifies equipment.

Volt/VAR optimization: A process for managing voltage and reactive power to improve efficiency on the distribution grid and reduce customer energy consumption.

Wide area network: A communications system that connects distribution substations and control centers. Components of the WAN include installing software and hardware, such as fiber optic cables, to convert data protocols and transmit data at expeditious speeds.

[END OF ATTACHMENT]