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Decision 18-03-023 March 22, 2018

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
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
And Related Matters.	Application 15-07-007 Application 15-07-008

DECISION ON TRACK 3 POLICY ISSUES, SUB-TRACK 2 (GRID MODERNIZATION)

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DECISION ON TRACK 3 POLICY ISSUES, SUB-TRACK 2 (GRID MODERNIZATION)

Summary

This decision addresses the issues identified in Track 3, Sub-track 2 (Grid Modernization), and provides a framework for Grid Modernization Guidance to inform future General Rate Cases (GRCs) as follows:

- Defines grid modernization with regards to its multiple objectives and the scope of Grid Modernization Plans;
- Establishes a classification framework to serve as a common vocabulary for grid modernization investments, and terminology to guide the organization and presentation of future GRC filings;
- Establishes the structure and timing of the grid modernization planning process, including the submission of Grid Modernization Plans and Grid Needs Assessments, and identifies how this fits into the larger Distribution Resources Planning (DRP) process;
- Provides guidance on how the Commission will evaluate the cost effectiveness of grid modernization investments proposed in future GRCs, including net ratepayer benefits;
- Establishes submission requirements for the grid modernization portion of future GRC requests, including how to justify each request; and
- Identifies next steps for further refining certain aspects of the grid modernization guidance adopted in this decision.

This proceeding shall remain open.

1. Background

On August 14, 2014, the Commission opened Rulemaking (R.) 14-08-013 in order to establish policies, procedures, and rules to guide California investor-owned utilities (IOUs) (Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company) in developing their Distribution Resource Plan (DRP) Proposals. We did so in accordance with Public Utilities Code Section (Pub. Util. Code §) 769, which established the IOUs' electric distribution planning protocols and the Commission's obligation to review, modify, and approve the IOUs' DRP proposals. Specifically, Pub. Util. Code § 769 b(4) required the IOUs to "identify any additional utility spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding net benefits to ratepayers."

The IOUs filed their Distribution Resource Plans on July 1, 2015, which were consolidated into the R.14-08-013 proceeding. Given the complexity and plethora of issues in this proceeding, the January 27, 2016 Scoping Memo and Ruling divided this proceeding into three Tracks, with Track 3 focused on policy issues. The subsequent August 9, 2016 *Assigned Commissioner's Ruling on Track 3 Issues* divided Track 3 into the three subtracts:

- Sub-track 1: DER Adoption and Distribution Load Forecasting;
- Sub-track 2: Grid Modernization Investments; and
- Sub-track 3: Integration of DRP into Planning and Cost Recovery Processes.

The October 21, 2016 *Assigned Commissioner's Ruling* (*October 21, 2016 (ACR)*) on Track 3 policy issues 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 Distributed Energy Resources (DERs)?" Issues 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 types of information a utility must provide in order to justify the necessity or cost-effectiveness of a proposed DER-related grid modernization investment.

In response to the *October 21, 2016 ACR*, the Commission's Energy Division held a workshop and prepared a Staff White Paper on Grid Modernization (White Paper), issued by ruling for party comment on May 16, 2017. The White Paper proposed a framework by which the Commission could evaluate proposed grid modernization investments, and direct utilities to make the appropriate investments to enable DER growth while maintaining safety and reliability, with just and reasonable impacts to ratepayers. The White Paper classified types of grid modernization investments, proposed a grid modernization planning process, and considered options for reviewing proposed investments and for methods to evaluate ratepayer benefits. The White Paper posed several questions for stakeholder comment, to which stakeholders submitted responses on June 19, 2017, and reply comments on June 28, 2017. Nine parties commented on the ruling and White Paper: the Joint IOUs, The Utility Reform Network (TURN), the Office of Ratepayer Advocates (ORA), Environmental Defense Fund (EDF), Interstate Renewable Energy Council (IREC), Green Power Institute (GPI), Vote Solar and the Solar Energy Industries Association (SEIA), Siemens, and the National Resources Defense Council (NRDC).

2. Discussion

2.1. Definition and Scope of Grid Modernization

Pursuant to Pub. Util. Code § 769, the Commission set out to establish a working definition of Grid Modernization in the context of the DRP proceeding based on the legislation's objective: that the IOUs propose any additional spending on distribution infrastructure necessary to integrate cost-effective DERs into the distribution system consistent with the goal of yielding net ratepayer benefits.[1] In its examination of industry literature, the White Paper observed that grid modernization technologies often serve multiple purposes: while there are some investments needed specifically to integrate DERs, the purpose of many of these investments is to mitigate safety and reliability impacts as an increasing penetration of DERs are integrated on to the grid. Furthermore, additional Grid Modernization-related distribution investments necessary to improve safety and reliability but unrelated to DER integration also exist, but these were not the focus of the White Paper.

The White Paper proposed that the scope of this guidance should include all grid modernization investments that are related to DERs, but that the scope would be limited to only the DER integration issues that drive these investments. This includes investments that both enable DER penetration and enhance safety and reliability, but does not include investments made solely for the purpose of increasing safety and reliability. The White Paper asked parties to comment on what types of investments should be considered in and out of scope for the purposes of this proceeding. The Joint IOUs and Siemens suggest that the grid

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[1] Pub. Util. Code § 769 (b) (4-5).

modernization guidance should be limited to supporting local DER distribution deferral services. Other parties, including GPI, SEIA, IREC, ORA and TURN, support a more expansive definition, stating that the DRP should consider all investments that might support DER integration. IREC states that the definition should also be expanded to include enhancing consumer choice and ensuring equitable distribution of benefits to ratepayers.

TURN points out the challenge in trying to isolate the drivers of grid modernization for the purpose of evaluating DER-related investments, stating that utility distribution planning cannot be readily separated into DER versus reliability versus safety investments, since most assets serve multiple functions and use cases. Over time, grid planning should be incorporated into utility risk-informed decision-making, with Grid Modernization Plans providing just one input into the overall process.

We agree with TURN that the Commission must evaluate IOUs' grid modernization proposals holistically, in consideration of their multiple objectives. This means that a separate evaluation of proposed grid modernization investments for DER integration, without consideration of the safety and reliability impacts, would not be feasible. The Grid Modernization Guidance shall apply to all investments that are related to DER integration, including investments that are also driven by safety and reliability needs. This scope includes both the autonomous growth of DERs as well as locationally targeted DERs that provide grid services.[2] This guidance does not encompass

[2] Autonomous growth is defined as voluntary customer adoption of DERs as a result of existing rates and tariffs,. Locationally targeted DERs is defined as geographically

Footnote continued on next page

the entire universe of legacy distribution investments typically requested in a GRC, or investments made solely for safety and reliability purposes. It includes technologies that are of a next generation character, and play some role in DER integration, as described in Appendix B. We thus adopt staff's proposed definition of Grid Modernization with the following modifications as recommended by the parties:

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

There are two specific challenges with adopting a more inclusive and holistic definition of Grid Modernization that need to be addressed: scope and cost-reasonableness. The first is that we are adopting the White Paper's proposed scope of DER-related investment that must be included in the utilities' Grid Modernization Plans. Given that DER integration-related investments are inherently intertwined with safety and reliability objectives, in most instances, we see no workable path to only provide guidance for DER-driven grid modernization. The Safety Model Assessment Proceeding (SMAP) proceeding is

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targeted DER sourcing and procurement to achieve specified distribution deferral opportunities and/or specified policy objectives.

concerned with safety and could in theory address grid modernization exclusively associated with safety.[3] Reliability-related investments are regularly proposed in GRCs and some of these can be considered grid modernization investments. In light of these challenges, and in recognition that all grid modernization investments will be reviewed and approved in GRC proceedings, this guidance should apply to all proposed grid modernization expenditures that have any relationship with DER integration. Specifically, this guidance shall apply to all types of grid modernization technologies listed in Appendix B. The Commission recognizes that this list may change as technology evolves, and we discuss the process for updating Appendix B later in the Decision.

The second challenge with the holistic approach to grid modernization guidance is the evaluation of cost reasonableness of grid modernization investments. Pub. Util. Code § 769 qualifies that "Spending may be approved if ratepayers would realize net benefits and costs are just and reasonable." As such, Pub. Util. Code § 769 holds grid modernization investments for DER integration to a potentially higher threshold than other GRC expenses, since other GRC requests are currently evaluated on the basis of whether they are just and reasonable, and not net ratepayer benefits. We have concluded that different methods of evaluating cost reasonableness are commonly applied in GRCs for different investments and for appropriate reasons. We do not require a single approach to cost reasonableness for all grid modernization investment proposals.

[3] The Safety and Enforcement Division Risk Assessment and Safety Advisory Staff's "Risk and Safety Aspects of Southern California Edison's 2018-2020 General Rate Case Application 16-09-001" concluded that it would be unwise to accept SCE's risk-assessment methods used in their Application as a basis for determining reasonableness of safety-related program requests.

We will discuss how to address the different approaches of cost reasonableness review in Section 2.3.4.

In their comments on the staff White Paper, TURN raises some additional concerns regarding the scope of grid modernization. The DRP Guidance Ruling in 2015[4] stated that the goal of the DRP is to create a distribution grid that is "plug-and-play" for DERs. TURN recommends clarifying that the definition of "Grid Modernization" should not mean creating a "plug-and-play" grid, irrespective of cost. TURN argues that this could lead to the widespread adoption of all grid modernization technologies that could far outstrip the benefits they provide, and that the concept should be qualified by consideration of the cost of DER interconnection. In response to TURN's comments, we acknowledge that cost effectiveness should remain a consideration in developing a "plug and play" grid.

Finally, we respond to TURN's request for clarification on the role of grid modernization respective to IOUs' Electric Rule 21 Tariffs. This decision only applies to GRC investments that are triggered by the expectation of cumulative impacts of DERs in a particular area. DERs remain subject to the interconnection rules in the Rule 21 Tariffs if an individual installation triggers a distribution upgrade. Questions regarding interconnection costs borne by wholesale DER developers are more appropriately addressed in the interconnection proceeding, R.17-07-007.

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[4] *Assigned Commissioner's Ruling on Guidance for Pub. Util. Code § 769 – Distribution Resource Planning (Guidance)*; Issued February 2, 2015.

2.2. Classification Framework for Grid Modernization Investments

This DRP proceeding was tasked with providing guidance to future GRCs to identify distribution grid technologies and/or functions that are needed to enable greater DER penetration, integration, and value maximization. To do so, the White Paper proposed a classification framework to identify and prioritize proposed grid modernization investments in order to understand the function of these technologies and the integration challenges they solve. The White Paper requested party comment on whether the framework accurately categorizes grid modernization technologies for purposes of GRC investment evaluation.

Some parties, such as ORA, find the proposed classification system to be confusing and of limited use regarding the ultimate goal of determining which technologies should be funded as supportive of Assembly Bill (AB) 327. Some parties express concern that staff's proposed framework is too narrowly focused on the technologies proposed by Southern California Edison (SCE) in its pending 2018 GRC,[5] and recommend that we adopt the inventory of functions and technologies developed by the U.S. Department of Energy's (DOE's) Next Generation Distribution System Platform (DSPx).[6] ORA also argues that the grid modernization decision should provide technical guidance for the GRC to identify the distribution grid technologies that are required to support DER integration.

It is not our intent to determine which technologies should be funded by GRCs, as suggested by ORA. That would pre-judge the GRC process. Our intent

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[5] A.16-09-001.

[6] https://doe-dspx.org/sample-page/modern-distribution-grid-report.

has been and remains to provide a framework to help improve the information presented in the GRC to better inform Commission GRC decision making. The classification framework in no way dictates what can or cannot be approved in the GRC for Grid Modernization. It is an information tool to help organize the information presented in the IOUs' triennial GRC funding request.

We clarify that the purpose of the classification system is to build a common vocabulary around different grid modernization technologies, their use cases, and the types of issues they resolve in order to frame the decision-making questions that GRCs need to evaluate. The evaluation of grid modernization investments occurs in the GRC process. The framework also guides how a GRC grid modernization request should be organized, such that the IOUs have a useful format for presenting information. We offer the IOUs guidance on which technologies can help integrate DERs, but the determination of whether they are needed and whether the costs are justified remains squarely in the GRC process.

Much of the content of the staff-proposed classification framework was informed by elements of the DOE's DSPx. While we recognize that the DSPx can serve as a useful reference, we do not adopt the entire DSPx classification system to inform GRCs, because we do not find that its structure aligns with the specific issue to resolve within the DRP.

2.2.1. Modifications to the Classification Framework

In response to party comments, we make some modifications to the classification framework in this decision and then discuss the process and timing of future changes to the framework. Our intent is to ensure that the classification framework is useful and relevant as grid modernization technologies and grid needs evolve over time.

The last column in Appendix B was modified to address the concern that it is too focused on SCE's 2018 GRC. Instead of "SCE 2018 GRC Application Categorization," the last column header now reads "Utility GRC Application Volume and Category." We order the IOUs to update the table to include reference their GRC applications for their proposed investments, where applicable. SEIA and Vote Solar point out that there may be additional technologies that may need to be integrated into the classification system as the market evolves. Specifically, they identify that technologies that support Distribution Market Operations were not included.[7] We agree that investments to support market operations are relevant, and direct the IOUs to add such technologies to the framework, as well as any additional new types of technologies that are needed to support the use cases defined with the scope of this decision and file as a Tier 2 Advice Letter that addresses the information identified in this paragraph within 60 days of this decision.

There were no comments on the proposed Appendices on the Function of Grid Modernization Investments or Distribution System Tools[8] and Technologies. We adopt these appendices in this decision, but reserve the right to modify them as needed.

SEIA and Vote Solar critique the List of Potential System/Integration Challenges provided in Appendix E of the White Paper, stating that many of these challenges will be resolved in part by smart inverters, DERs such as energy

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[7] Comments of the Solar Energy Industries Association and Vote Solar on the Assigned Commissioner's Ruling Requesting Answers to Stakeholder Questions Set Forth in the Energy Division Staff White Paper on Grid Modernization, Attachment 2.

[8] Appendix C, Functions of Grid Modernization Investments and Appendix D, Distribution System Tools in the White Paper are attached to the this decision in Appendix C.

storage, and by mitigations identified during the interconnection process. We agree that the IOUs should identify how DERs and smart inverters can meet some of these integration challenges as part of their Grid Modernization Plans. However, these challenges are the crux of why grid modernization investments are potentially needed. In Appendix E of the White Paper, we identified the challenges to inform future GRC decision making on the types of potential investments that may be needed to address specific integration challenges. The classification framework including the list of System Integration Challenges[9] shall not prejudice the Commission for or against a particular solution to a specific DER integration challenge. The case for or against a particular investment will be made in the GRC process. We direct the IOUs in their Grid Modernization Plans to use the tools developed in the DRP proceeding to present the level(s) of DER penetration at which these integration challenges are expected to arise, and what the most cost-effective mitigation options are. This includes stating, for instance, whether smart inverters can address stated integration challenges or whether new investments are needed.

Parties raised a few additional categories necessary to evaluate the Grid Modernization Plans. ORA states that there is an additional classification category that is essential for determining the long term costs and benefits of DER integration: each proposed investment type should be categorized by the DER(s) for which it is needed for integration. The Joint IOUs suggest that questions surrounding whether a given grid need is system-wide versus location-specific, and supports autonomous DER growth versus targeted DER deployment are

[9] Appendix E in White Paper is included in this decision in Appendix C.

two additional categories needed to understand the justification of proposed grid modernization investments.

We agree with ORA and the Joint IOUs and direct the IOUs to update Appendix B, to identify which DER(s) each proposed grid modernization investment supports; whether the investments are system-wide versus location-specific; and whether the investments are needed to accommodate autonomous DER growth and/or targeted DER deployment. We update the matrices and lists of definitions developed for the White Paper based on parties' recommendations, and include the tables and definitions in Appendices B-C to this decision. We direct the IOUs to fill in the sections of the matrices to include the additional classifications that were recommended by ORA and the IOUs, and file as a Tier 2 Advice Letter within 60 days of this decision.   If the IOUs find that changes to the classification system are necessary to more accurately reflect their GRC proposals, they may propose modifications via Tier 2 Advice Letter prior to their GRC filing, with sufficient time to make adjustments to the GRC filing, in the event of a resolution.

Finally in their comments to the Proposed Decision, ORA recommended additional technologies should be added to the grid modernization classification tables: DG production meters, grid sensors, remote controlled switches, AMI and Smart Inverters. We support the addition of the following technologies to the extent that they are utility-owned, ratepayer funded assets that are requested in the GRC. We direct the IOUs to add grid sensors and remote controlled switches in the classification tables. Consideration of AMI and smart inverters are already included in the GMP submission requirements.

2.3. Grid Modernization Planning and Review Process

The White Paper proposed the following steps for development, review, and approval of the IOUs' Grid Modernization Plans:

1. Annual DRP Grid-level Scenarios and Assumptions;
2. DRP Annual Grid Needs Assessment (GNA);
3. Grid Modernization Plan (GMP) Submission;
4. Grid Modernization Plan Review; and
5. GRC Authorization of Grid Modernization Investments.

We adopted components of Steps 1 and 2 in the Track 1 decision, D.17-09-026, for the Integration Capacity Analysis (ICA) and Locational Net Benefits Analysis (LNBA) tools, as well as DER Growth Scenarios. We adopted the GNA in the Track 3 decision, D.18-02-004. In this decision, we determine that the GRC is the appropriate forum to submit, review, and evaluate Grid Modernization Plans. Grid modernization investment requests will be specific to each IOU, as their evaluation cannot be separated from the context of the overall distribution revenue requirement. We thus find that an additional review process prior to the GRC will be impractical. It would also be burdensome to staff and parties to create an additional regulatory process.

2.3.1. Application of Circuit-Level Planning Assumptions in Grid Modernization Planning

The first two steps of the planning process described in Section 2.3 are shared by the Distribution Investment Deferral Framework (DIDF) and Grid Modernization Planning. The process and methodologies for development of these planning assumptions were addressed in the Track 1 decision, D.17-09-026, and the Track 3 decision, D.18-02-004.

- **DER Growth Scenarios**: The Commission determined in the Track 3 decision that DER growth forecasts are to be established by the California Energy Commission's (CEC's) Integrated Energy Policy Report (IEPR) Demand Forecast. The decision broadened the scope to consider distribution load forecasting. Disaggregation of the forecasts to the circuit level will be further reviewed in the Distribution Load Forecasting Working Group in 2018.

- **Integration Capacity Analysis**: The Track 1 decision adopted the methodology for the ICA, to calculate 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 grid upgrades are needed.
- **Locational Net Benefit Analysis**: The Track 1 decision adopted an LNBA methodology for calculating avoided distribution upgrades, avoided transmission expenditures, and avoided system-level costs such as energy and Resource Adequacy. It also directed the utilities to refine the LNBA to fully capture location-specific transmission & distribution (T&D) costs and benefits. These refinements include calculating DER integration costs stemming from proposed Grid Modernization or hosting capacity-related investments, and clarified that such integration costs should be calculated for each DER technology at the distribution planning area (DPA) level.

We affirm the guidance in the Track 1 and 3 decisions and add further points of direction to support our grid modernization objectives. Consistent with the objectives and direction of the Track 1 decision, we expect the IOUs to apply the DRP planning tools to inform and justify their GRC-proposed levels of spending on grid modernization costs related to DER integration. As noted earlier, we define Grid Modernization investments for DER integration broadly to mean the distribution grid technologies and functions that enable greater DER penetration, integration, and value maximization, as well as that promote safety and reliability. We emphasize the importance of utilizing DRP tools in developing Grid Modernization investment requests, and require the GMPs to be based on DER growth forecasts from the IEPR forecast and associated ICA and LNBA results.[10] In their comments on the Proposed Decision, the Joint Utilities raised the concern that alignment with IEPR could become problematic, for instance, the 2017 IEPR will be applied to the 2018-19 GNA, which will be applied to the 2021 Test Year GRC. The Commission may need to revisit this issue in DRP proceeding in 2018. The IOUs' GMPs should provide a rationale for assigning a proportion of a given proposed investment to DER integration, safety, or reliability.

2.3.2. Application of Grid Needs Assessment to the Grid Modernization Planning Process

The White Paper proposed the GNA to be an annual IOU submission requirement that would catalog the distribution system deficiencies that result from the annual distribution planning process. This report would provide public access to circuit level planning assumption data and the distribution upgrades that form the basis of the IOUs' grid modernization funding requests and proposed distribution deferral projects. The White Paper asked parties for input on what information should be included in the GNA to support grid modernization, whether it should be submitted formally, and how it would inform the grid modernization planning process.

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[10] D.18-02-004 clarified that the IOUs may propose modifications to the forecast based on policy changes that have a measurable impact on DER forecasts *via* Tier 2 Advice Letter.

Decision 18-02-004 adopted GNA submission requirements pertaining to the DIDF. D.18-02-004 determined that the GNA shall be an annual report that is not subject to Commission approval, as the IOUs need to proceed with implementation of their distribution planning process without delay, and also as to not subject the IOUs' funding and investment decisions to additional scrutiny outside of the GRC. The report will allow the Commission and parties to review the list of grid needs along with the planning assumptions that underlie these needs, in order to provide transparency into the IOUs' distribution planning process. The GNA, as adopted by D.18-02-004, limits reported "grid needs" to four types of forecasted circuit level system deficiencies, associated with the four distribution services that DERs can provide as adopted in D.16-12-036: capacity, voltage support, reliability, or resiliency. In the GNA, the IOUs shall identify locations with deficiencies, identify the forecasted overload of the existing equipment, and note the forecasted timeframe by which the deficiency must be addressed. In this decision, we address party IREC on the GNA submitted in response to the White Paper, and provide additional GNA requirements pertaining to Grid Modernization investments.

ORA, Vote Solar, and SEIA request that the GNA include additional data to that required by D.18-02-004. These requests include a list of all distribution upgrade projects, their costs, a catalog of all substations and circuits, reserve margins, historic loading, voltage profiles, and expected forecasting error.

In considering these parties' comments, we affirm the need to strike a balance between transparency and regulatory burden, given that implementing and maintaining the ICA, LNBA, and GNA already require the IOUs to produce a significant amount of data on an annual basis. Certain data sets are already required to be presented in other filings. Per D.18-02-004, we have required the

IOUs to identify planned investments in the Distribution Deferral Opportunity Report (DDOR). Costs of planned investments will be reviewed in the GRC, and thus should not be included in the GNA, to minimize redundancy. The ICA, adopted in D.17-09-026, will include a catalog of circuits and substations. Reserve margins can be calculated from data provided in the DDOR, so while it would not be available to provide in the GNA, we agree that the IOUs should include the data in DDOR. Historical data would be extensive and difficult to produce relative to the value it would provide, and is not available in a form that would be comparable to GNA going forward. The IOUs will begin to build a historical dataset once the GNA and DDORs are filed annually. Expected forecast error would be very problematic to quantify at this time, given that the forecasting methods and ICA have just been developed. However, a main task of Distribution Load Forecasting work going forward, per D.18-02-004, is to consider how to evaluate uncertainty in DER growth forecasts.[11] If any of these approaches are found to be problematic, parties may raise the issue for reconsideration following the first GNA.

We will require one additional data point to be included in the GNA, beyond the requirements adopted by D.18-02-004. In order to assess the long-term costs of DER integration, the IOUs need to identify the primary driver of the grid need—whether a forecasted deficiency is *primarily* driven by DER growth, demand growth, aging infrastructure, another factor or a combination of factors. This data will enable the IOUs to identify DER integration costs, which

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[11] D.18-02-004 determined that the scope originally defined in the DER Growth Scenarios sub-track of the proceeding shall be expanded to include load. This issue area will be referred to as Distribution Load Forecasting.

are a critical input to a Common Resource Valuation Methodology (CRVM) for Integrated Distributed Energy Resources (IDER) and Integrated Resource (IRP).

2.3.2.1. Locational Prioritization of Grid Modernization Investments

In the White Paper, Staff proposed a schema for prioritizing location-specific grid modernization investments. Staff proposed that the prioritization ranking would be included in the GNA, and would provide a rating for each circuit based on DER growth and LNBA and ICA results, which would inform high-priority locations for grid modernization investments. While several parties agree that there need to be evaluation criteria and scoring methodology to justify the locations and extent of locational investments, IREC argues that it is problematic to define a rigid schema that assigns equal weight to each DRP tool to determine where investments should occur. They suggest that it may be more useful to identify a flexible set of guidelines for determining locational prioritization that also considers the urgency of grid needs, as well as the costs of potential DER-driven investments. We agree that the IOUs need to determine the locations where grid modernization investments are needed, and consider the schema that staff proposed in the White Paper conceptual and not prescriptive. We decline to require the IOUs to apply this prioritization schema; however, we require the IOUs to explain the basis for determining the locations where each proposed grid modernization investment is needed based on forecasted DER growth, ICA, and LNBA. We further require that the IOUs' GMPs use information from DRP tools to support their rationale for a given grid modernization investment. If a circuit has low hosting capacity, but high expected DER growth, what investments are proposed?

2.3.3. Grid Modernization Plan Submission and Review

The White Paper proposed that to evaluate grid modernization investments, the IOUs need to prepare a comprehensive GMP that articulates their proposal for the infrastructure upgrades necessary to integrate DERs. The White Paper proposed a list of submission requirements and presented several options for how the GMP should be submitted and reviewed, proposing that the plan may be submitted in the DRP to be evaluated either formally or informally prior to the IOUs' GRC applications. The White Paper considered how frequently GMPs should be produced, as well as the time horizon the GMPs should cover.

ORA, SEIA, Clean Coalition, and IREC agreed that there should be some review process prior to GRC applications; SEIA stated that a preliminary review process is necessary because it is difficult for parties to participate in GRCs, due to their length and scope. TURN, Siemens, and the IOUs state that GMPs should not be reviewed separately from the GRC. While we acknowledge SEIA's concern, we find that additional processes would further stretch parties' capacity to participate in proceedings if the processes are duplicative, and that the IOUs' GMPs cannot be evaluated without regard to the benefits of DER integration and increased safety and reliability.

Our general conclusion is that GMP review and evaluation should occur in the GRC. The technological upgrades needed to integrate DERs are too specific to each IOU to make generalized conclusions about them. The GRC process already effectively accomplishes the objectives required by Pub. Util. Code § 769, and intervening parties' examination of the IOU funding requests in the GRC is a critical component to ensure that we meet these objectives at the lowest possible cost. While it can be time consuming for parties to participate in GRC proceedings, it is the only way to sufficiently vet the IOUs' grid modernization funding requests to ensure that they are reasonable. We have included the list of GMP Submission Requirements in Appendix A. However, we find that it would be beneficial to the process to require the IOUs to provide at minimum a one day workshop to present their initial Grid Modernization Plans at least 60 days prior to the GRC filing, to present their 10 year vision and outline of their funding request, so that the parties have an opportunity to provide initial input prior to the filing. The GMPs may not be finalized at the time of the workshop; we expect the IOUs to address issues raised in the workshop in their GMP submissions.

We recognize that GRCs only address three years of funding, and that grid modernization is a long-term process. Distribution Resource Planning that meets an optimized resource mix to achieve our greenhouse gas (GHG) targets in the long term requires us to consider the evolving growth trends of each DER. There are some foundational questions that need to be answered to evaluate Grid Modernization Plans in years beyond the IOUs next GRC cycle, as the specific trajectory for different types of grid modernization investments will depend on the deployment patterns and integration needs for each type of DER. Therefore, we require each IOU to present a 10-year Grid Modernization vision to provide context for their GMP request. The 10-year vision should focus on the distribution system changes the IOU anticipates to be necessary considering the long-term outlook for different types of DERs. The IOUs shall include the 10-year vision as a chapter in their GMP.

2.3.4. Evaluation for Cost Reasonableness of Grid Modernization Plans

Pub. Util. Code § 769 (b)(4) requires the IOUs to "identify any additional utility spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding net benefits to ratepayers."[12] The legislation stipulates that utility spending on DER integration should be pursued to the extent that the DER growth is cost-effective.

The White Paper proposed the following options for evaluating the cost-effectiveness of proposed grid modernization investments: 1) utilize existing methods, such as customer outage minutes; 2) develop a benefit/cost methodology; 3) apply a least cost/best fit framework; or 4) assess net benefits as a component of the IRP optimization analysis. Parties in comments primarily preferred two approaches: to apply a least cost/best fit approach that requires the IOUs to describe their alternate investment options and explain why they recommend a given investment. They also argued that the LNBA should be adapted to quantify the system level costs and benefits of DER integration. TURN and SEIA find that net benefits should be primarily quantified through the LNBA, and TURN and NRDC state that cost-effectiveness evaluation may require multiple methods. TURN points out that most GRC litigation essentially uses Option 1 (customer outage minutes) to evaluate utility proposals.

There are challenges to establishing a method to evaluate the cost effectiveness of grid modernization requests related to DER integration. As discussed in Section 2.1, grid modernization investments can span a portfolio of interrelated distribution expenditures that simultaneously support DER

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[12] Pub. Util. Code § 769 (d) requires that "Any electrical corporation spending on distribution infrastructure necessary to accomplish the distribution resources plan shall be proposed and considered as part of the next general rate case for the corporation. The commission may approve proposed spending if it concludes that ratepayers would realize net benefits and the associated costs are just and reasonable. The commission may also adopt criteria, benchmarks, and accountability mechanisms to evaluate the success of any investment authorized pursuant to a distribution resources plan."

integration and ensure safety and reliability. Pub. Util. Code § 769 set a potentially different standard for evaluating cost reasonableness for grid modernization investments related to DER integration than is employed for traditional distribution requests related to safety and reliability. To determine the cost effectiveness of each grid modernization investment, the IOUs would need to identify the driver of the investment and isolate the value of its contribution to enabling DER growth. We find this infeasible, given the multiple, interrelated functions of grid modernization investments.

Meanwhile, investments that are only driven by safety and reliability are held to the common standard for evaluating GRC funding requests, in which a proposed expenditure must be found "just and reasonable." Thus, proposed investments that are characterized as supporting both the integration of DERs and ensuring safety and reliability face a potentially higher threshold of review than a distribution request that supports safety or reliability alone. Holding investments to these separate standards could potentially result in the perverse outcome that would make it more difficult for IOUs to support DER growth, and then the IOUs may be incented to avoid identifying DER integration as a driver of grid investments in order to avoid triggering the higher standard of review. This is not our intent.

Due to these challenges, we do not find Option 2, the proposal to develop a grid modernization cost effectiveness methodology, to be realistic. The benefits of each grid modernization investment cannot be isolated from the benefits provided by the other grid investments. Instead, the cost-effectiveness of grid modernization needs to be evaluated within the context of the overall cost-effectiveness of the DERs. The methodology to calculate the cost-effectiveness of DERs is under consideration in the IDER decision, which will inform procurement policies to optimize the resource mix in the IRP proceeding.

Future DER growth projections will drive the need for Grid Modernization investment related to DER integration. The tools we are developing in the DRP—ICA, LNBA, and GNA—as well as the cost effectiveness methodology and DER souring policies under consideration in the IDER proceeding, are working to enable cost effective DER procurement. The IOUs shall use these tools to develop their Grid Modernization Plans, which shall focus on grid modernization investment needed to integrate the forecasted DERs levels in their Commission approved Growth Scenarios. This includes anticipated levels of autonomous growth of DERs, anticipated targeted DER procurement under the DDIF, and other current and future DER sourcing methods developed in IDER.

The IOUs should plan grid modernization for the forecasted level of DERs that has been determined in CEC's IEPR forecast, as directed in D.18-02-004, which represents CEC's estimate of DER growth under existing statewide policy. When the Commission updates the pricing policy to reflect changes to the cost effective value of DERs in the future, *e.g.* revisit net energy metering (NEM) revision anticipated in 2019, the CEC will update the IEPR forecast to reflect this change. When the Commission incorporates locational value into DER incentive levels, DER growth forecasts will need to consider how to incorporate these changes into their disaggregated forecasts.

While we will not require a method to quantify a *cost-effectiveness* showing in order to evaluate grid modernization investments in the GRC, careful vetting of the *cost reasonableness* of these requests remains a critical role for the GRC to meet distribution planning objectives at the lowest possible cost. In their GRCs, the IOUs shall continue to propose the lowest cost approach to meeting these grid needs, and should provide an explanation for what is causing the need for each type of investment as part of the GRC submission requests. We find that current GRC approaches are effective and appropriate, and should continue to be used.

With the exception of Option 2 in the White Paper, we find that all of the remaining approaches play an important role in determining the appropriate levels of investment in DER integration, and that Options 1 and 3 are currently used to review distribution funding requests. The most appropriate approach to evaluate the cost reasonableness depends on what drives an investment: (1) to integrate and maximize the value of DERs, (2) to mitigate forecasted safety and reliability challenges based on either growth of DERs, or growth in demand, or (3) combination of these drivers.

Option 1 applies to distribution upgrades that improve safety and reliability, and is currently used in GRCs to evaluate proposed distribution investments. IOUs should continue to apply traditional reliability metrics, such as the system average interruption duration index (SAIDI) wherever applicable.

Option 3 proposes that the IOUs identify the lowest cost approach to meeting grid needs and present alternative options. This standard of evaluation may apply to investments driven by DER integration or by safety and reliability mitigation, and should be addressed whenever alternative options are available.

Option 4 will occur in the IRP proceeding, and will inform future DER sourcing policy and IEPR growth forecasts. In order to effectively value the cost effectiveness of DERs, it is essential that IOUs provide the DER integration costs as an input into these analyses. The LNBA, once fully implemented, will inform cost effectiveness evaluations of different DER resources within the IDER proceeding. Grid Modernization investments, along with other DER integration costs, must be considered against the benefits presented in the LNBA in order to determine the cost-effectiveness of each DER. For this reason, we find it is critical for the IOUs to identify the drivers of grid needs in the GNA and propose the most appropriate method to quantify the DER integration costs to incorporate into the LNBA. The process will be addressed in the next phase of this proceeding.

The appropriate scale and types of grid modernization investments will depend on long term growth of DERs and whether they reach penetration levels that lead to operational challenges on the distribution system. Therefore, the critical questions for the GRC to determine are when certain grid modernization investments might be necessary, and whether costs are reasonable. There are foundational investments needed in the near term to enable the IOUs to plan for and monitor DERs operating on the system regardless of the level of DER penetration. However, many potential grid modernization investments may meet an anticipated future need to mitigate grid deficiencies that are not forecasted to materialize within the next GRC cycle. Thus, we expect IOUs to present longer term grid modernization investments objectives that don't fit neatly within a three year GRC funding cycle. For this reason, we order the IOUs, in their 10-year Grid Modernization vision, to identify the entire scope of an upgrade program, what portion was completed in previous GRC cycles, and what portion is necessary to complete within the next three year cycle and thereafter.

2.3.4.2. Performance Based Metrics

In their comments on the White Paper, TURN and ORA raise the concern that grid modernization investments meant to capture the value of DERs may provide net benefits that may be theoretically available but not actually realized.

ORA points to a 2012 Advanced Metering Infrastructure (AMI) case study that found that the projected benefits of SCE's smart meter program never materialized as net reductions in rates, and stresses that it is essential to track costs and benefits throughout the life of an investment. ORA argues that the only way that this can be accomplished is if the IOUs are required to use specific accounting codes for each type of grid modernization investment, which should be defined in advance of the expenditures. TURN reinforces this concern, and recommends performance based metrics to penalize utilities if the benefits of grid modernization investments are not realized.

We find it problematic to consider penalizing the IOUs for failing to realize the benefits of grid modernization investments, given questions regarding where DERs will be installed and how they perform are highly uncertain and outside of the IOUs' control. Penalizing the IOUs would undermine their willingness to invest in supporting DER integration if they are held financially responsible for the realization of DER forecasts. Nevertheless, it is important that IOUs track the realization of forecasted grid needs in order to evaluate the impact of these investments in the future.

We recognize the implications of TURN's and ORA's concern, however, and agree that it is important to track grid modernization investments as they are implemented over time, in order to assess the degree to which they realize the benefits for which they were proposed. We agree with ORA's recommendation that the IOUs should use consistent accounting codes that are clearly defined and provide reference to any past accounting codes for related investments. We direct the IOUs to develop a consistent means of tracking grid modernization expenditures over multiple rate case cycles and provide this reference within their GMPs. For example they could designate a new accounting code to add to these investments that do not change over time, similar to FERC codes. We will also require the IOUs to list the status of projects from the previous GRC in the GMP. The Commission will then need to assess the implications of these results in future Grid Modernization Plans.

2.3.5. Grid Modernization Plan Submission Requirements

In the Distribution chapter of their GRC filings, the IOUs shall submit a Grid Modernization Plan that provides information for each proposed grid modernization program, listed in Appendix A. A "grid modernization program" includes the comprehensive costs to support each type of technology upgrade. The IOUs must demonstrate the need for any grid modernization investments within the three-year GRC funding cycle, given the forecasted DER growth, as well as results from the ICA, LNBA, and GNA. The first chapter of an IOU's GMP shall be its 10-year Grid Modernization vision. To facilitate Commission and party review of the GMPs in the GRC, all grid modernization investment requests shall be made in one volume, if possible, to enable streamlined review. If this is not possible, grid modernization investment requests should be summarized in a single table with citations to the chapters covering each request.

2.4. Future Refinement of Grid Modernization Guidance and Next Steps

This guidance will first apply to PG&E's Test Year 2020 GRC and to all IOUs' subsequent GRCs thereafter, unless otherwise ordered by the Administrative Law Judge (ALJ) or assigned Commissioner in an open GRC proceeding. The Commission may reconsider whether additional technical guidance is necessary as DER growth trends evolve, as the DRP tools are completed and applied to the DIDF and Grid Modernization plans, or in response to decisions in other proceedings. Otherwise, the Commission intends to formally revisit Grid Modernization in 2021.

3. Categorization and Need for Hearing

This decision confirms that Track 3 of these consolidated proceedings is categorized as quasi-legislative. While the Scoping Memo and Ruling anticipated that there may be hearings, none were requested.

4. Comments on Proposed Decision

The proposed decision of Commissioner Picker in this matter was mailed to the parties in accordance with Pub. Util. Code § 311. On March 12, 2018, the following parties served opening comments: California Efficiency and Demand Management Council; Interstate Renewable Energy Council; Joint IOUs (Pacific Gas and Electric Company, Southern California Edison, and San Diego Gas and Electric Company); Green Power Institute (GPI); California Energy Storage; Office of Ratepayer Advocates,; Clean Coalition; and SEIA/Vote Solar. On March 19, 2018, SEIA/Vote Solar; Joint IOUs; ORA; and GPI served their reply comments. The comments focused on the following portions of the decision: (1) Grid Modernization definition; (2) scope (classification tables); (3) Grid Modernization review process; (4) Grid Modernization submission requirements; (5) future refinements, general issues, and possible issues for resolution in future proceeding phases; and (6) the appendices.

The decision has been revised, as needed, to address comments that requested either minor clarifications or non-substantive edits. The decision has also been revised in the following substantive ways: Ordering Paragraph 3 has been revised to include additional requirements for the updates to the Grid Modernization Classification Tables; and Appendix A (Grid Modernization Submission Requirements) has been revised to include additional requirements for the 10-year vision for grid modernization; and Operations and Management expenses must be itemized.

5. Assignment of Proceeding

Michael Picker is the assigned Commissioner and Peter V. Allen and Robert M. Mason III are the co-assigned ALJs in this proceeding.

Findings of Fact

1. The Commission set out to establish a working definition of grid modernization in the context of this DRP proceeding.

2. The Commission's Energy Division White Paper pointed out that grid modernization technologies often serve multiple purposes: *e.g.*, DER integration, safety, and reliability.

3. The White Paper asked parties to comment on what types of investments should be considered in and out of scope of this proceeding for purposes of grid modernization.

4. The grid modernization guidance developed herein should apply to all proposed grid modernization expenditures that have any relationship with DER integration, including those that are primarily driven by safety and reliability.

5. This proceeding was tasked with providing investor-owned utilities with the guidance to identify distribution grid technologies and/or functions that are needed to enable greater DER penetration, integration and value maximization in their GRCs.

6. The White Paper proposed a classification framework to identify and prioritize grid modernization investments in order to understand the function of these technologies and the integration challenges they solve.

7. The purpose of the classification system is to build a common vocabulary about the types of grid modernization technologies, their use cases, and the types

of issues they resolve in order to frame the decision-making questions that GRCs need to evaluate.

8. The IOUs in their GRC filings on Grid Modernization should use the tools developed in the DRP proceeding to present the level of DER penetration at which certain integration challenges are expected to arise, and what the most cost-effective mitigation options or investments are.

9. The IOUs' Grid Modernization Plans should be reviewed and evaluated in the GRC, as the types of technological upgrades needed to integrate DERs are too specific to each IOU to make generalized conclusions outside of a GRC.

10. The benefits of each grid modernization investment cannot be isolated from the benefits provided by the other grid investments.

11. The cost of grid modernization should be considered within the context of the overall cost-effectiveness of the DERs. The Commission will evaluate the cost effectiveness of DERs and establish the procurement policies to optimize the resource mix in the IRP and IDER proceedings.

12. The White Paper presented four options for evaluating the cost effectiveness of grid modernization investments. With exception of Option 2, all of these approaches are necessary to evaluate the IOUs' proposed investments.

13. The IOUs need to use consistent accounting codes that are clearly defined and provide reference to any past accounting codes for related investments.

14. In the Distribution chapter of the GRC filing, the IOUs shall submit a Grid Modernization Plan that provides information for each grid modernization program proposed, listed in Appendix A.

Conclusion of Law

1. It is reasonable to adopt the recommendations from the Staff White Paper on Grid Modernization since those recommendations are consistent with the directives set forth in Pub. Util. Code § 769.

2. It is reasonable to find that current GRC approaches to review cost reasonableness are effective and appropriate, and should continue to be used.

3. The GRC process already effectively accomplishes the objectives required by Pub. Util. Code § 769, and intervening parties' examination of the IOU funding requests in the GRC is a critical component to ensure that we meet these objectives at the lowest possible cost.

4. Pub. Util. Code § 769 set a potentially different standard for evaluating cost reasonableness for grid modernization investments related to DER integration than is employed for traditional distribution requests related to safety and reliability.

O R D E R

IT IS ORDERED that:

1. This decision adopts the proposed definition of grid modernization as follows:

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

relative to other legacy investments of a less modern character.

2. The grid modernization guidance developed herein shall apply to all proposed grid modernization expenditures that have any relationship with distributed energy resources integration as well as those that are primarily driven by safety and reliability.

3. The investor-owned utilities (IOUs) shall submit updates to the Grid Modernization Classification Tables (Appendices B and C) via Tier 2 Advice Letter within 60 days of this decision to identify which DER(s) each proposed grid modernization investment supports; whether the investments are system-wide versus location-specific; and whether the investments are needed to accommodate autonomous DER growth versus and/or targeted DER deployment. We direct the IOUs to add grid sensors and remote controlled switches in the classification tables. If the IOUs find that changes to the classification system are necessary to more accurately reflect their General Rate Case (GRC) proposals, they may propose modifications via Tier 2 Advice Letter, with sufficient time to make adjustments to the GRC filing, in the event of a resolution. Parties may recommend alternate modifications to the classification tables in their protests to the advice letter.

4. The investor-owned utilities (IOUs), in their General Rate Case (GRC) filings on grid modernization, shall use the tools developed in the Distribution Resources Plan proceeding to present the level of distributed energy resource penetration system integration challenges that are expected to arise on the grid, and what the most cost-effective mitigation options or investments are. Specifically,

- The IOUs shall apply the Distribution Resources Plan planning tools to inform and justify GRC-proposed grid modernization spending related to Distributed Energy Resources integration.

- The IOU's Grid Modernization Plan (GMP) included in its GRC must explain the rationale for the proportion of investment that can be attributed to Distributed Energy Resources integration, safety, or reliability.
- In order to assess the long-term costs of Distributed Energy Resources (DER) integration, the IOUs shall identify the primary driver of the grid need: whether the forecasted deficiency is primarily a result of DER growth, demand growth, equipment replacement, or other factor.
- The IOUs shall explain the basis for determining the locations where each type of grid modernization investment is needed. We require that the IOUs' GMP use information from Distribution Resources Plan tools to support their rationale for a given investment.
- The IOUs shall present their GMPs in the GRC for review and evaluation.
- Each IOU shall present a 10-year vision for its GMP in order to provide context for its GRC-specific GMP request. The 10-year vision shall include the changes an IOU anticipates to be necessary to the distribution system in light of the long term Distributed Energy Resources growth forecast. The IOUs shall include the 10-year vision as a chapter in their GRC filings.
- In their GRCs, the IOUs shall propose the lowest cost approach to meeting identified grid needs while also maximizing DER benefits, and should provide an explanation for the drivers of each type of investment. The GMP shall also discuss whether any of the proposed distribution investments in the GMP could otherwise be met by DERs.

5. The investor-owned utilities shall continue to apply traditional reliability metrics, such as the system average interruption duration index (SAIDI), to evaluate investments that provide safety and reliability benefits.

6. The cost of grid modernization shall be considered within the context of the overall cost-effectiveness of Distributed Energy Resources (DER). The Commission will evaluate the cost effectiveness of DERs and establish the procurement policies to optimize the resource mix in the Integrated Resource Planning and Integrated Distributed Energy Resource proceedings.

7. The investor-owned utilities (IOUs) shall identify the drivers of grid needs in the Grid Needs Assessment and propose the most appropriate method to quantify the Distributed Energy Resources integration costs to incorporate into the Locational Net Benefit Analysis. The IOUs shall file their Grid Modernization Plan as a chapter in their General Rate Case filings to include the information listed in Appendix A.

8. The investor-owned utilities (IOUs) shall use consistent accounting codes that are clearly defined and provide reference to any past accounting codes for related investments. We direct the IOUs to develop such accounting codes and provide this reference within their Grid Needs Assessments.

9. This guidance will first apply to Pacific Gas and Electric Company’s Test Year 2020 General Rate Case (GRC), and to each investor-owned utility’s ’ subsequent GRC, unless otherwise ordered by the Administrative Law Judge or assigned Commissioner in an open GRC proceeding.

10. Rulemaking 14-08-013 *et al*., and Application 15-07-005 *et al*., shall remain open.

This order is effective today.

Dated March 22, 2018, at San Francisco, California.

MICHAEL PICKER
President
CARLA J. PETERMAN
LIANE M. RANDOLPH
MARTHA GUZMAN ACEVES
CLIFFORD RECHTSCHAFFEN
Commissioners

APPENDIX A –

Grid Modernization Submission Requirements

Grid Modernization Plan Overview

This section will provide a general overview of the IOU's approach to grid modernization as an introduction to their planning request:

1. **10-year Vision for Grid Modernization**
   a. What long term changes will be necessary to meet the 10 year forecast of DER growth
      i. High level status of grid modernization upgrades initiated and completed to date
      ii. Additional spending requirements necessary to complete the grid modernization objectives, within and beyond the current GRC cycle
      iii. A high level but complete status of DER related research, development and demonstration (RD&D) projects planned, in process, proposed and/or approved.
   b. Foundational technologies
      i. Are there foundational planning and communications technologies that are critical for distribution system planning for DER integration that have not been installed?
      ii. And does the investment in these foundational technologies together with the capabilities they enable outweigh the "traditional" solution to provide the needed capability?
   c. DER-specific integration challenges
      i. For each type of DER, what types of integration challenges are anticipated occur?
      ii. What type of distribution system upgrades are critical to mitigate each of these challenges?
      iii. How, and to what degree, does the Grid Modernization Plan enable two-way flows of electricity?
   d. DERs as Grid Services
      i. DERs that can serve as an alternative to meet each type of challenge
      ii. What additional technology upgrades, if any, are needed to enable DERs to provide grid services
   e. Role of existing and customer technologies in achieving objectives:
      i. Explain how the grid modernization proposal leverages existing AMI infrastructure, third party communication networks, and smart inverters to support grid modernization objectives

2. Overview of Current GRC Grid Modernization Request

a. Narrative discussion of proposed grid modernization programs and program drivers for this GRC cycle, with examples

   b. Cost summary of Grid Modernization Plan: List of total amount requested

   c. Attach classification table

Grid Modernization Program Requirements

For each grid modernization program request the IOUs shall provide the following:

1. **Capital Budget**
   a. Proposed itemized costs for proposed program
   b. If proposed budget for 3 year GRC period covers a portion of the overall cost of the proposed program, please provide the total program costs, including expenditures already incurred and remaining costs[1]
2. **Investment Capabilities**
   a. The full list of investments (projects) proposed
      i. Technology capabilities:
         1. System integration challenges the technology supports
         2. Grid services the technology enables
      ii. Supporting technologies: Which other investments are necessary to also be installed in order to enable the proposed investment
   b. Maturity of proposed technology: Discussion of the technological development of the proposed investment, and if emerging, what type of technology it is replacing
   c. Expected useful life of equipment
   d. Equipment capacities, ratings, and other specifications
3. **Investment Justification**
   a. Investment Drivers: Identify what primary grid need is driving each grid modernization request and how the proposed investment meets that need [2]

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[1] For instance, an upgrade project that will cover a limited percentage of the IOU circuits in each GRC period, identify the portion of the program that has been completed and remains to be completed in future GRC cycles

[2] Drivers may include (a) Supporting targeted distribution deferral with DERs; (b)Accommodate autonomous DER growth that has socialized interconnection costs; (c) Ensure system safety;

Footnote continued on next page

b. Attribution to DER integration: Percentage of costs directly attributable to DER integration vs. safety and reliability

c. Which DERs does the proposed technology integrate

d. Investment alternatives, including existing equipment and DERs

4. Operations and Management (O&M) Expenses

a. List itemized cost and description of O&M expenses to maintain, repair and update grid modernization systems.

5. Status of Currently Funded Projects

a. Description of the status of the current equipment installed

b. List of any project requests authorized in the previous GRC that were not completed

6. Cost Reasonableness

a. Proposed method for assessment of cost reasonableness

b. Result of cost reasonableness assessment

7. Additional Information for Locational Investments

a. Description of need: Explanation of the basis for determining scale and location of the investment need

b. Deployment Plan: Implementation schedule for projects, or discussion of determination of when distribution upgrades need to be deployed

(END OF APPENDIX A)

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meets outcomes of Safety Model Assessment Proceeding (SMAP) and Risk Assessment Mitigation Phase (RAMP); (d) Maintaining reliability while expanding DER (e) Increasing reliability for Worst Circuit Rehabilitation (WCR) circuits ; (f) Increasing reliability system wide

APPENDIX B

Classification of Grid Modernization Investments

APPENDIX B: Classification of Grid Modernization Investments

Terms used are defined in Appendix C

A. Technology Category[1]	B. Use Cases[2]	C. Function	D. System wide or Local	Distribution System Management Activities	E. DERs that apply[3]	F. System/ Integration Challenges Addressed	Examples	GRC Application Categorizations[4]
Long Term Planning Tools	HDA, S&R, GDS	DER Forecasting, DER Valuation Solution Analysis, Circuit Modeling	System wide	Distribution Planning	*IOUs to fill in*	Thermal, Operational Limitations	Integrated Load and DER forecasting, solution analysis for capacity/reliability, solution analysis comparing DER to traditional upgrades	*Each IOU should enter the reference their GRC request, if applicable*
System Modeling Tool	HDA, S&R, GDS	DER Forecasting, DER Valuation Solution Analysis, Circuit Modeling	System wide	Distribution Planning		Sustained voltage violations, thermal, protection	Integration Capacity Analysis (ICA)	

1 From Figure 2, list of technologies.

2 Acronyms represent: 1) High DER Adoption (HDA); 2) Safety & Reliability (S&R); 3) Grid and DER Services (GDS)

3 IOUs shall enter the DER(s) that the listed technology category serves to intetgrate

4 SDG&E and PG&E should add their GRC application references to the classification table

A. Technology Category[1]	B. Use Cases[2]	C. Function	D. System wide or Local	Distribution System Management Activities	E. DERs that apply[3]	F. System/ Integration Challenges Addressed	Examples	GRC Application Categorizations[4]
Grid Connectivity Model[5]	HDA, S&R, GDS	Circuit modeling, data used for Forecasting and DER Value and Solution Analysis	System Wide	Distribution Planning, Grid Operations, Market Operations		Items 1 - 8 of list of challenges	Base data layer for ICA, Load and DER forecasting, state estimation	
Data Sharing Portals	HDA, S&R, GDS	DER Valuation Solution Analysis, Circuit Modeling	System wide	Distribution Planning		Sustained voltage violations, thermal, protection	Data Sharing Portal (web interface)	
Grid Analytics Application	HDA, S&R, GDS	Circuit/System Modeling	System wide	Distribution Planning Grid Operations		Sustained voltage violations, thermal, protection, asset management	Asset management, sensing and measurement (data), improves quality of asset data to improve distribution planning inputs and operational decisions	
Interconnection Processing Tool	HDA, S&R, GDS	Circuit/System Modeling	System wide	Distribution Planning		Indirect impact on sustain voltage violations, thermal, protection (interconnection process)	Customer facing application to support streamlining the interconnection process, improve distribution planning.	

[5] Not included in Figure 2

A. Technology Category[1]	B. Use Cases[2]	C. Function	D. System wide or Local	Distribution System Management Activities	E. DERs that apply[3]	F. System/ Integration Challenges Addressed	Examples	GRC Application Categorizations[4]
Grid Management System / DERMS	HDA, S&R, GDS	Sensing & Measurement, Data & Device Comms., Control & Feedback Systems, Reliability Management, Cybersecurity	System wide	Distribution Grid Operations, Market Operations		Items 2 - 10 of list of challenges	Distributed Energy Resource Management System (DERMS), Advanced Distribution Management System (ADMS), integrated with outage management and energy management systems	
Substation Automation and Common Substation Platform (CSP)	HDA, S&R, GDS	Sensing & Measurement, Data & Device Comms., Control & Feedback Systems, Reliability Management, Cybersecurity	Local	Distribution Planning, Grid Operations, Market Operations		Items 1 - 10 of list of challenges	SCADA, coordinated distribution device control with DERs, protection, cybersecurity	
Volt Var Optimization	HDA, S&R, GDS	Sensing & Measurement, Data & Device Comms., Control & Feedback Systems	Local	Distribution Planning, Grid Operations, Market Operations		Voltage fluctuation, sustained voltage violations, Low (Secondary) Voltage Controllers	Automated programmable capacitor controls, integration with DMS and EMS, future integration with smart inverters	

A. Technology Category[1]	B. Use Cases[2]	C. Function	D. System wide or Local	Distribution System Management Activities	E. DERs that apply[3]	F. System/ Integration Challenges Addressed	Examples	GRC Application Categorizations[4]
Intelligent Automated Switches	HDA, S&R	Sensing & Measurement, Data & Device Comms., Control & Feedback Systems, Reliability Management	Local	Distribution Planning, Grid Operations, Market Operations		Masking Load, Thermal, Operational Limitations, Fault Location &Service Restoration, Cybersecurity	Remote Intelligent Switches, Augmented Remote Control Switches, Automated Automatic Reclosures	
Remote Fault Indicators	HDA, S&R, GDS	Sensing & Measurement, Data & Device Commas.	Local	Distribution Planning, Grid Operations, Market Operations		Thermal, Operational Limitations, Cybersecurity	Wireless bi-directional fault indicators	
Field Area Network	S&R, GDS	Sensing and Measurement, Data & Device Comms., Cybersecurity	Large Local Areas, eventually system wide	Distribution Planning, Grid Operations, Market Operations		Items 1 - 10 of list of challenges	Wireless radios, routers	
Wide Area Network	S&R, GDS	Sensing and Measurement, Data & Device Comms., Cybersecurity	Large Local Areas, eventually system wide	Distribution Planning, Grid Operations, Market Operations		Items 1 - 10 of list of challenges	Fiber optic and IP connectivity	

(END OF APPENDIX B)

APPENDIX C
Classification Definitions

APPENDIX C
Classification Definitions

A. Technology Types included in Grid Modernization

This list summarizes the technologies included in the classification of Grid Modernization investments. 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,[1] 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 combined with the other Grid Modernization programs, it allows customers to track the

[1] Supervisory control and data analysis

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, and also may include low voltage controllers located in the secondary voltage portion of the distribution grid. Supervisory-controlled distribution substation capacitors, and low (secondary) voltage controllers, and existing standard automated distribution field capacitors on distribution circuits are leveraged to reduce energy consumption, while maintaining overall customer service voltage requirements by lowering service voltage toward the lower end of the ANSI C84.1 standard.

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.

B. 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:

1. **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.

2. **Grid and DER Services:** Locational targeted DERs, such as those being piloted in the Integrated Distributed Energy Resources (IDER) Incentives pilot[2] 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 distribution grid. It also refers to functions and capabilities that are needed to enable DERs to participate in wholesale markets.

3. **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.

C. Functions of Grid Modernization

The section categorizes grid modernization technologies based on their function in distribution system management. These categorizations are defined by the IOUs and informed by the U.S. Department of Energy's DSPx project.[3]

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.

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[2] Adopted by D.16-12-036.

[3] More information on DOE's DSPx can be found at http://doe-dspx.org/

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.

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.

D. System-wide v. Local Investments

1. **System-wide investments:** System wide investment is a project that is implemented to meet the needs of the entire distribution system. These investments primarily include a software system, that enables the IOUs to model circuit level activity

2. **Local investments:** Local investments include hardware that is installed on the distribution system to meet a circuit or location specific grid need.

E. Distribution System Management Activities

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 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 mod els 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.

E. List of Potential System/Integration Challenges

General Issues	Description	Grid Modernization Functional Group	Technologies to Mitigate Challenge[4]
Voltage Fluctuation[5]	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[6], Energy Storage
Sustained Voltage Violations	Power generation on a circuit increases voltage and power usage decreases voltage. DERs may consequently cause nearby voltages	Distribution Grid Operations	Smart Inverters, Load Tap Changers,

4 Examples are not limited to those procured by utilities.

5 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.

6 Communication Systems may include 3rd party communications infrastructure and does not pre-determine the communication systems are utility-owned.

General Issues	Description	Grid Modernization Functional Group	Technologies to Mitigate Challenge[4]
	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.		Voltage Regulators, Capacitors[7], Communication Systems, Energy Storage
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, Smart Inverters, Energy Storage

[7] 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[4]
Thermal[8]	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, Energy Storage
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

8 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[4]
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, Smart Inverters
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
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,

General Issues	Description	Grid Modernization Functional Group	Technologies to Mitigate Challenge[4]
			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

(END OF APPENDIX C)