PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

AGENDA ID: 17212

ENERGY DIVISION **RESOLUTION E-4982**

March 14, 2019

R E S O L U T I O N

Resolution E-4982. Approval of Updates to Grid Modernization Classification Tables, pursuant to Decision (D.) 18-03-023.

PROPOSED OUTCOME:

- This Resolution approves Grid Modernization Classification Tables, with modifications, for PG&E, SCE and SDG&E.
- This Resolution requires PG&E and SDG&E to refile its Grid Modernization Classification Tables with references to their TY 2020 GRC and TY 2019 GRC, respectively.

SAFETY CONSIDERATIONS:

- Resolution establishes a framework for reviewing IOUs' General Rate Case Grid Modernization distribution requests for investments to ensure safety and reliability while integrating Distributed Energy Resources.

ESTIMATED COST:

- This Resolution entails no incremental costs.

By Pacific Gas and Electric Company Advice Letter 5300-E-A filed on December 3, 2018, Southern California Edison Company Advice Letter 3807-E filed on May 21, 2018 and 3807-E-A on November 20, 2018, and San Diego Gas & Electric Company Advice Letter 3229-E-A filed on November 27, 2018

SUMMARY

On May 21, 2018, Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E)—collectively, the Investor-Owned Utilities (IOUs)—filed Advice Letters (ALs) 5300-E, 3807-E, and 3229-E, respectively, proposing updates to the Grid Modernization (Grid Mod) Classification Tables in compliance with Ordering Paragraph (OP) 3 of Decision (D.)18-03-023. In response a timely protest filed by the Public Advocate's Office of the Public Utilities Commission (CalPA)[1], PG&E filed AL 5300-E-A on December 3, 2018 date replacing AL 5300-E in its entirety, SCE filed AL 3807-E-A on November 20, 2018 replacing AL 3807-E in part, and SDG&E filed AL 3229-E-A on November 27, 2018 replacing AL 3229-E in its entirety.

This Resolution approves the three IOUs' ALs, with modifications, replacing the individual grid modernization classification table with a common table, included as Attachment A. PG&E and SDG&E are required to refile their Grid Mod Tables with references to their TY 2020 GRC and TY 2019 GRC, respectively. The common table includes two new technology categories that are within the scope of Grid Modernization: Microgrid interface and Utility-owned Storage. If PG&E has requested funds for either of these technology categories in their TY 2020 GRC, they shall submit errata testimony to include these requests within their Grid Modernization Plan. The IOUs are required to use the table in Attachment A for future GRCs, but may propose modifications to the table by a Tier 2 advice letter if necessary.[2]

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[1] Senate Bill 854 (Stats. 2018, Ch. 51) amended Pub. Util. Code Section 309.5(a) to, in part, rename the Office of Ratepayer Advocates as the Public Advocate's Office of the Public Utilities Commission. We will refer to this party as CalPA.

[2] D.18-03-023 at OP 3

BACKGROUND

In the Distribution Resource Planning Rulemaking (R.)14-08-013, the Commission adopted the Grid Modernization Guidance for future General Rate Cases (GRCs), in order to identify distribution grid technologies and/or functions that are needed to enable greater penetration, integration, and value maximization of Distributed Energy Resources (DERs). We did so in accordance with Public Utilities Code Section (Pub. Util. Code §) 769 b(4), which 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 Grid Modernization Guidance was adopted in D.18-03-023, which established a process for the development, review and approval of the IOU's Grid Modernization Plans within the IOUs' General Rate Cases. The decision set the submission requirements for the Grid Modernization Plans (GMP), and determined what types of distribution investments are within scope to be included in the GMPs.

D.18-03-023 adopted a classification framework "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."[3] The framework defined the scope of technologies that Grid Modernization Guidance applies to. The framework also guides how a GRC grid modernization request should be organized, such that the IOUs have a useful format for presenting information.

The Commission determined that "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."[4] The Commission

[3]Ibid, pg. 11
[4] Ibid at OP 2

determined that this guidance shall apply to all types of grid modernization technologies listed in Appendix B.[5]

The decision directed the IOUs to submit updates to the Grid Mod Tables (Appendices B and C of D.18-03-023) via Tier 2 Advice Letter within 60 days of the 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 non-locationally targeted[6] DER growth versus and/or targeted DER deployment. We directed the IOUs to add grid sensors and remote-controlled switches in the classification tables. We determined in D.18-03-023 that 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. Parties were permitted to recommend alternate modifications to the classification tables in their protests to any Advice Letter.[7]

<u>PG&E Advice Letter 5300-E-A</u>

PG&E submitted AL 5300-E on May 21, 2018 requesting approval of its updated Grid Mod Tables, which were included in the AL as Attachment A. PG&E filed Supplemental AL 5300-E-A on December 3, 2018 to replace AL 5300-E in its entirety. The supplemental advice letter was filed in response to the protest by the CalPA and subsequent discussions between CPUC's Energy Division staff, the CalPA and the IOUs, in order to better align the Grid Mod Tables across the IOUs. In compliance with OP 3 of D. 18-03-023, PG&E has updated the columns in the classification tables for 1) DERs that apply to each technology category,

[5] D.18-03-023, pg. 7
[6] D. 18-03-023 applied the "autonomous" DER growth to refer to DERs that resulted from existing tariffs in programs. Since this term applies a different definition in other proceedings, we will refer to this type of DER growth as non-targeted DER growth.
[7] Ibid at Ordering Paragraph 3

and 2) Non-locationally targeted DER growth v. Targeted DER Deployment; and added technologies and examples to the table and list of definitions that should be classified as Grid Modernization. Modifications in AL 5300-E-A primarily consist of reorganization of technology categories and edits to the glossary of definitions.

SCE Advice Letter 3807-E and Advice Letter 3807-E-A

SCE submitted AL 3807-E on May 21, 2018 requesting approval of its updated Grid Mod Tables, which were included in the AL as Attachment A. SCE filed AL 3807-E-A on November 20, 2018 in response to CalPA's protest, which supplements Advice 3807-E in part, replacing Appendices B and C of AL 3807-E. SCE provided modifications to the organization of the original classification table and added references for clarity, and provided some edits to the grid modernization definitions in Appendix B. In AL 3807-E-A, SCE made additional updates to the classification tables to better align across the IOUs.

SDG&E Advice Letter 3229-E

On May 21, 2018, SDG&E submitted the Grid Mod Tables in AL 3229-E, with modifications to the tables that reclassified which technologies should be considered within scope of the Grid Modernization Guidance, as well as modifications to Appendix C, List of Potential System/Integration Challenges. SDG&E filed AL 3229-E-A on November 27, 2018 as a supplemental Advice Letter to replace the original AL 3229-E in its entirety. SDG&E's supplemental Advice Letter revised their proposed updates to the classification tables in collaboration with Energy Division, CalPA and the other IOUs, to reflect a table format that is consistent with those of the other IOUs.

While SDG&E's classification table includes the same technology categories as are included in the PG&E's and SCE's submitted tables, SDG&E states that they do not currently view several of the categories included in these tables as applicable to "Grid Modernization" and, therefore, will not include them in their "Grid Modernization" table filed in the GRC. SDG&E states that they have not yet developed a Grid Modernization Plan for their next GRC, and thus anticipate filing a Tier 2 Advice Letter proposing modifications to Appendices B and C prior to SDG&E's next GRC.

In their proposed update, SDG&E classifies the following technology categories of Grid Modernization Investments, as driven primarily by DERs, and provides the following examples:

- Data Sharing Portals: Data sharing portal (web interface)
- Interconnection Processing Tool: Customer facing application to support streamlining the interconnection process, improve distribution planning
- Grid Management Systems/Distributed Energy Management Systems (DERMS): DERMs, Advanced Distribution Management System (ADMS), integrated with outage management and energy management systems
- Volt/Var Optimization: Automated programmable capacity controls, integration with DMS and EMS and future integration with smart inverters

SDG&E classified the following technology categories as "Other Investments" that are "not Grid Modernization driven primarily by DER," and thus not subject the Grid Modernization Submission Requirements listed in Appendix A of D.18-03-023. The technology categories included the following examples:

- Long Term Planning Tools: Integrated Load and DER forecasting, solution analysis for capacity/reliability, solution analysis comparing DER to traditional upgrades, LoadSEER
- System Modeling Tool: Power Flow, Integration Capacity Analysis (ICA), Synergi
- Grid Connectivity Models: Base data layer for ICA, Load and DER forecasting, state estimation, Real Time Bulk Electric System (BES) management
- Grid Analytics Application: Asset management, sensing and measurement (data), improves quality of asset data to improve distribution planning inputs and operational decisions

- Substation Automation and Common Substation Platform (CSP): SCADA, coordinated distribution device control with DERs, protection, cybersecurity
- Intelligent Automated Switches: Remote Intelligent Switches, Augmented Remote Control Switches, Automated Automatic Reclosers
- Remote Fault Indicators: Wireless bi-directional fault indicators
- Field Area Network: Wireless radios, Routers
- Wide Area Network: Fiber optic and IP connectivity

NOTICE

Notice of PG&E AL 5300-E, AL 5300-E-A, SCE AL 3807-E and AL 3807-E-A, and SDG&E AL 3229-E-A was made by publication in the Commission's Daily Calendar. The IOUs state that they served copies of the ALs to the interested parties on the GO-96-B and R.14-08-013 service lists.

PROTESTS

The California Public Advocates Office[8] (CalPA) protested the IOUs' Advice Letters and Supplemental Advice Letters. CalPA states that while the IOUs ALs generally meet the explicit requirements of OP 3 of D.18-03-023, with the exception of SDG&E's modifications discussed below, CalPA proposes modifications to the classification tables as well as overall recommendations aimed at developing a common classification framework and definitions across all three IOUs.

CalPA submitted a timely protest to PG&E AL 5300-E, SCE AL 3807-E, and SDG&E AL 3229-E on June 11, 2018, which lead to the supplemental advice letter filed by the three IOUs. CalPA filed a protest the IOU's Supplemental ALs on

[8] Senate Bill 854 (Stats. 2018, Ch. 51) amended Pub. Util. Code Section 309.5(a) to, in part, rename the Office of Ratepayer Advocates as the Public Advocate's Office of the Public Utilities Commission. We will refer to this party as CalPA.

December 10, 2018, to which the IOUs filed replies to the protest on December 17, 2018.

CalPA submitted a timely protest in response to the supplemental advice letters, PG&E AL 5300-E-A, AL 3807-E-A, and SDG&E AL 3229-E-A on December 11, 2018. In their protests of the Supplemental ALs, CalPA made the following recommendations to apply to the three IOUs:

1. The Commission should adopt Attachments 1 and 2 of the Public Advocates Office's Original Protest (Original Protest) as the next iteration of the Tables;
2. Disposition of the ALs should clarify that common Grid Mod Tables and definitions do not force or constrain requests for specific investments in the Grid Modernization Plan (GMP) which are included in each IOU's General Rate Case (GRC) application, and that GMPs need only include Grid Mod Tables for each IOU's current GMP request;
3. Commission staff should facilitate a workshop to discuss potential modifications to the Grid Mod Tables to be scheduled in the second quarter of 2019; and

CalPA argues that a standardized classification framework would aid the CPUC and parties in their evaluation of the IOU's GRC Grid Mod Plan requests, and help ensure that accommodation for DERs, and enablement of DER benefits, do not vary based on a customer's service territory. The CalPA states that the Grid Mod Tables provided in the Supplemental ALs continue to provide a limited set of technologies based largely on SCE's TY 2018 GRC application, with minor updates to better align across IOUs, but they do not result in a common table or common set of definitions. The CalPA states that the IOUs also fail to include technologies requested in recent GRCs as DER related, and technologies added by the CalPA based on its simultaneous participation in the DRP proceeding and the GRC proceedings.

CalPA provided comments on specific technology categories included in each IOU's table, which were incorporated into CalPA's proposed edits to a consolidated classification table. CalPA provided specific recommendations to reorganize the classification tables, which included providing the following:

- additional columns for each IOU's GRC request with the sources of each technology category;
- a column to identify whether each technology category supported non-locationally targeted DER growth and/or targeted DER deployment;
- columns to reference the original source of a proposed technology category and the party that proposed the technology category; and
- additional rows for other technologies proposed in GRCS and in other IOUs' ALs, and a row for alternatives to technologies. The rows potentially identify additional investments that should be considered within scope of the Grid Modernization Guidance to include:
    - DER Head End: DER Communications/Control Interface
    - Adaptive Protection Systems: Capability within Grid Management System (GMS), protection settings change in real time based on grid conditions
    - Remote Controlled Voltage Control Devices: Load tap Changers (LTCs), Capacitor banks and voltage regulators with ability for VVO control via upgrade or replacement
    - Primary Circuit Reinforcement: Installing new manual switches, upgrading sections of cable/ conductor, extending feeder lines to create new ties
    - Secondary Circuit Upgrades: Smart transformers, VVO transformers, secondary conductor and service drop upgrades
    - Distribution Circuit Protection Device Upgrade: Replace fuses with breakers; upgrade switch control systems to accommodate backflow
    - Utilitiy Owned Storage: Energy storage systems installed on the distribution systems to buffer DER output and load (PEV)

- o Microgrid Switchgear: "Trayer" switches and other hardware and software which allow DER powered microgrids to operate in islanded mode
- o Alternates to New Technology: Upgrades to existing systems, employee training, improved inventory control, increased O&M expense

In their protest to the Supplemental ALs, CalPA addressed concerns that the IOUs raised during informal discussions held in October 2018 with the CalPA and Energy Division. CalPA clarified that the IOUs would not be held responsible for including data regarding the Grid Mod requests from the other two IOUs in their GMPs. CalPA recommends that disposition of the ALs should explain that common Grid Mod Tables and definitions do not force or constrain an IOU to deploy particular technologies in their GMPs, and that GMPs need only include Grid Mod Tables for their current GMP request.

Finally, CalPA points out that each IOU added a column to indicate whether each technology supports non-locationally targeted versus targeted DER deployment as directed by D.18-03-023. However, each IOU indicated applicability to both types of DER growth for all technology categories, which essentially nullifies any value for this added column of data. CalPA agrees that none of the technology categories appears to apply exclusively to only one of these types of DER. Unless other parties or CPUC staff identify how this category adds value to the table, CalPA states that this column should be removed.

IOUs Replies to Protests of Supplemental Advice Letters

PG&E Response: PGE&E states that the CalPA acknowledges that PG&E's proposed Grid Mod Classification Tables provided in PG&E's original advice letter are already consistent with D.18-03-023. In response to the CalPA's recommendations to the original AL, PG&E has incorporated several updates into the updated Grid Mod Classification Tables submitted in PG&E AL 5300-E-A. PG&E clarified that the technology additions proposed by CalPA, are already included in the updated tables submitted in PG&E AL 5300-E-A, and notes where each of these technologies is included in the tables. PG&E notes one exception, they consider utility-owned storage to be categorized as a DER in and of itself.

SCE Response: SCE states that there are inherent differences among the IOUs' GRC applications and electric distribution systems, and that a single set of documents negates the reality that the IOUs have different service territories, different customers, different demand profiles and different needs at different times looking for the most optimal solutions that provide the best value. Responding to CalPA's assertion that a standardized classification document should not "force or restrain requests for specific investments in the Grid Modernization Plan included in the IOU's GRC," SCE finds that CalPA's recommended appendices (which the GMP would be guided by) include technology categories that are unique to each IOU.

SDG&E Response: SDG&E posits that each IOU responds to distribution grid needs based on unique regional needs and the state of their distribution infrastructure. According to SDG&E, attempting to classify future investment requests relative to non-applicable past investments reflected in a common classification as proposed by CalPA would be both burdensome and unnecessary.

SDG&E disagrees with CalPA's recommendation to hold a workshop in the second quarter of 2019 to discuss new DER related Grid Modernization technologies, stating that the process for updating the Grid Modernization tables has already been established in D.18-03-023, OP 3. IOUs may propose modifications to the Classification Tables via Tier 2 Advice Letter, and parties may propose alternate modifications to the classification tables in their protests.

CalPA's IOU Specific Recommendations

In their protests, CalPA identified specific recommendations for PG&E and SDG&E. CalPA's did not provide any recommended changes that were unique to SCE.

<u>**CalPA's Recommendations for PG&E**</u>

PG&E should issue a Tier 2 AL adding references to its TY 2020 GRC to the Grid Mod Tables after its GRC application is filed.

In the discussion in their original protest, CalPA identified that PG&E did not provide references to PG&E's TY 2017 GRC and TY 2020 GRCs, as was required by OP 3 in D.18-03-023. References were also omitted from AL 5300-E-A.

CalPA states that it may be necessary for PG&E to file their Grid Modernization Plan as errata testimony if CPUC adopts CalPA's recommendations.

If the CPUC agrees that CalPA's recommended additions to the Grid Mod Table should expand the scope of the Grid Modernization Guidance, the initial testimony in PG&E's GRC application will not be consistent with D.18-03-023. In this case, CalPA states that it would be necessary for PG&E to revise its testimony based on the adopted Grid Mod Tables, and recommends that this revised testimony be filed as errata testimony by PG&E in a minimum of four months before Public Advocates Office's testimony in the PG&E's TY 2020 GRC is due in order to allow adequate time for discovery, analysis, incorporation into testimony, incorporation into Results of Operation (RO) modeling and testimony, and management review and editing.

<u>*PG&E Response:*</u> PG&E believes it has met its compliance obligations associated with OP 3 of D.18-03-023. However, in the event the Commission decides to adopt a modified version of the Grid Mod Table for use in utilities GRC applications, PG&E should not be required to update its 2020 GRC testimony. PG&E states that the purpose of the 2020 GRC is to present and explain its forecast for the 2020 GRC period, and that revising these tables would not result

in a change to PG&E's forecast, therefore no changes to PG&E's 2020 GRC testimony, which was filed on December 13, should be required.

PG&E also disagrees with CalPA's recommendation that PG&E add references from its 2017 GRC. PG&E does not believe it would be the best use of its resources to gather this information, given that parties to PG&E's GRC proceedings can obtain previous GRC filings from the Commission's website and perform a similar analysis.

CalPA's Recommendations for SDG&E

In its original protest, CalPA states that SDG&E's AL provided a limited showing that was not fully responsive to the explicit directions and intent of D. 18-03-023.

SDG&E did not provide references to their TY 2019 GRC. CalPA states that in their TY 2019 application (A.17-10-007) SDG&E includes multiple requests that are DER related, including microgrid projects, storage projects, smart secondary distribution transformers, DERMS, Demand Response Management System (DRMS), and other IT projects that are related to DERs, but did not include these in their classification table.

CalPA also concludes that SDG&E's proposed reorganization of the classification tables appears to be based on an assumption that the CPUC's adopted definition of Grid Modernization refers only to investments that are "primarily driven by DER;" and clarifies that the decision states "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***." SDG&E's proposed reorganization is not consistent with D.18-03-023 and should be rejected.

SDG&E Response: SDG&E states that the Grid Mod Tables should not include projects contained in SDG&E's filed 2019 GRC application. Attempting to reclassify these requests against the Grid Modernization classification table would be burdensome and unnecessary.

SDG&E also states that the proposed reorganization of the classification tables is to provide a clearer understanding of grid investments to distinguish between investments that are solely driven by DER for the purpose of grid modernization and those investments that would be required regardless of DER.

DISCUSSION

The Commission finds CalPA's recommendation to approve a common classification table to be reasonable, and the common classification table included as Attachment A of this Resolution is ordered to be used by all IOUs. A copy of the table is attached as Attachment A.

Upon review of the individual technology investments, we do not agree with SCE's claim that the distribution territories are so different that that the technology categories would not apply across the IOUs. In fact, the IOUs were able to work together to define common categories, and we find the IOU's Grid Mod Tables filed within their Supplemental ALs were effectively identical. We approve of PG&E and SCE's submitted table, with a few edits that make them consistent and interpretable across the IOUs.

SCE's concern that the Grid Mod Tables and definitions would force or constrain requests for specific investments in the Grid Modernization Plan in the GRC, was specifically addressed in D.18-03-023, which states that the "classification framework in no way dictates what can or cannot be approved in the GRC for Grid Modernization….the determination of whether they are needed and whether the costs are justified remains squarely in the GRC process."[9] We reiterate here that this table does not presume which technologies the IOUs should include in their GRC, they may note that a category is not applicable if

[9] D.18-3-023, pg. 10

they are making no requests, and may note a new technology to add to the list if it is not covered.

We require the IOUs to provide references to their pending GRC requests within the Classification Tables, so that parties can understand how the pending GRC request relates to the most recent Grid Modernization Plan. We find this to be a reasonable requirement for GRC filings.

We clarify that the "list of examples" should be characterized as the applicable technologies that include but are not limited to the technologies listed in the technology category. These investment requests should be addressed as part of the Grid Modernization Plan.

However, we find several of CalPA's specific recommendations for modifications to the Classification Tables to be unnecessary and do not include them in the adopted tables.

Specifically, we decline to include the following recommended columns, since their usefulness has limited applicability to a broader audience in the future:

- Original Source of Propose Technology Category
- PG&E TY 2017 GRC Request
- Party that proposed technology categories

Several of the rows of technology categories proposed by CalPA are in fact in scope, but not necessary as separate rows, for the reasons identified below. These include the following:

- DER Head End: This technology is already included in the existing DER Communications/ Control Interface category in the classification table
- Remote Controlled Voltage Control Devices: Technologies are included in the Volt/Var Optimization category
- Primary Circuit Reinforcement: Investments are included in the DER hosting capacity reinforcement category that was added in response to CalPA's original protest

- Secondary Circuit Upgrades: Investments are included in the DER Hosting Capacity category
- Distribution Circuit Protection Device Upgrade: Investments are included in the Relay Replacement and DER hosting capacity category
- Alternates to New Technology: O&M expenses are already required to be itemized in the Grid Modernization Plan submission requirements as part of each category of expenditures, so this data is already a part of the Grid Modernization Plan.

However, there were two technology categories that were omitted for the Grid Mod Tables submitted in the IOUs Supplemental ALs that we find to be necessary to include within the scope of Grid Modernization in order to have a complete understanding of how DERs are being integrated into the distribution system:

- Microgrid Interface: Microgrids are dependent on DERs to supply generation within the microgrid service area. We find it necessary to better understand the cost of microgrid investments within the context

- Utility Owned Storage: CalPA pointed out that DER integration has been used to justify Utility-owned storage, which would suggest that it is a DER integration related distribution investment. While it also is defined as a DER, we find it reasonable to define it as a Grid Modernization investment as well.

Finally, we agree with CalPA that the column to define whether a technology category supports non-locationally targeted growth v. specified deferrals does not add value to the table, and that this column should be removed.

The Commission finds CalPA's request for a workshop to discuss potential modifications to the Grid Mod Tables to be unnecessary.

D.18-03-023 established a process for updating the Grid Mod Classification Tables, stating that 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.[10] The Commission concluded that it 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. Further, the Commission intends to formally revisit Grid Modernization in 2021. Since we are currently adopting a final classification system that has yet to be applied to the each of the utilities' GRCs (their 1st GRC post D.18-03-023), now is not the time to revisit the Grid Modernization framework in a workshop.

PG&E-Specific Direction

If PG&E has requested funds for either of these technology categories in their TY 2020 GRC, they shall submit errata testimony to include these requests within their Grid Modernization Plan. Omission of references to the TY 2020 GRC does not comply with D.18-03-023 OP 3.

PG&E did not include references to their TY 2020 GRC requests in their Grid Mod Table, as required by D.18-03-023. Nor did they include references in the table that was submitted as part of AL 5300-E-A. In D.18-03-023 we ordered the IOUs to update the table to include reference their GRC applications for their proposed investments, where applicable. Appendix B, footnote 4 specifically states that SDG&E and PG&E should add their GRC application references to the classification table. We direct PG&E to file a supplemental compliance ltter to add the TY 2020 GRC reference to the adopted table.

SDG&E-Specific Direction

[10] Ibid, pg. 13

Omission of references to the TY 2019 GRC does not comply with D.18-03-023 OP 3.

As with PG&E, SDG&E did not include references for their TY 2019 GRC, which was under consideration during the period that this AL was filed. While we recognize that the decision states that this guidance will first apply to PG&E's Test Year 2020 GRC and to all IOUs' subsequent GRCs thereafter,[11] the decision also clarifies that the purpose of the classification system is to develop a reference to frame the decision-making questions that GRCs need to evaluate. SDG&E is not directed to reorganize their existing GRC filing to meet the Grid Modernization structure, but it is reasonable to require them to include references in the Grid Mod Table for their current GRC, as a reference for parties, as SCE has done for their TY 2018 GRC. We therefore direct SDG&E to file a supplemental compliance advice letter to add the TY 2019 GRC references to the adopted table.

SDG&E's characterization of the scope of Grid Modernization to be included in their Grid Mod Tables and addressed in their future GRC does not comply with D.18-03-023, OP 2.

In their submitted tables, SDG&E characterized several of the technology categories as "Other Investments" that are "not Grid Modernization driven primarily by DER," and thus not subject the Grid Modernization Submission Requirements listed in Appendix A of D.18-03-023. CalPA correctly points out that SDG&E's position is not consistent with the decision. 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***."[12] SDG&E is

[11] Ibid, pg. 26

[12] D.18-03-023, OP 2

directed to submit their Grid Modernization Plan in their next GRC in compliance with definition established in D.18-03-023.

COMMENTS

Public Utilities Code section 311(g)(1) provides that this resolution must be served on all parties and subject to at least 30 days public review and comment prior to a vote of the Commission. Section 311(g)(2) provides that this 30-day period may be reduced or waived upon the stipulation of all parties in the proceeding.

The 30-day comment period for the draft of this resolution was neither waived nor reduced. Accordingly, this draft resolution was mailed to parties for comments, and will be placed on the Commission's agenda no earlier than 30 days from today.

FINDINGS

1. CalPA's request for a common classification table and list of definitions is reasonable and is attached in Appendix A.

2. The Grid Modernization Plan Submission requirements apply to the technology categories included in the Grid Mod Tables in Attachment A.

3. CalPA's recommended additional technology categories are already included in the common Grid Modernization Classification Table, with the except of the following categories, which should be added to the Classification Table:

    - Microgrid Switchgear
    - Utility-Owned Storage

4. The adoption of common Grid Mod Tables and definitions do not force or constrain requests for specific investments in the Grid Modernization Plan (GMP) included in each IOU's General Rate Case (GRC) application. GMPs need only include Grid Mod Tables for each IOU's current GMP request.

5. D.18-03-023 established a process for updating the Grid Mod Tables, and for updating the Grid Modernization Guidance, and therefore, CalPA's recommendation for a workshop to reconsider the structure of the classification tables is unnecessary.

6. PG&E's omission of references to the TY 2020 GRC in their classification tables does not comply with the requirements in D.18-03-023 to include reference their GRC applications for their proposed investments, where applicable.

7. SDG&E's omission of references to the TY 2019 GRC does not comply with the requirements in D.18-03-023 to include reference their GRC applications for their proposed investments, where applicable.

8. SDG&E errs in its conclusion that the list of technology categories that are not driven by DERs is not within scope of the Grid Modernization Guidance, and will not be included in their TY 2022 GRC. D.18-03-023, OP 3 clearly states, "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."

THEREFORE IT IS ORDERED THAT:

1. PG&E AL 5300-E-A, SCE AL 3807-E and 3807-E-A, SDG&E AL 3229-E-A are approved as modified by this Resolution.

2. The common Grid Modernization Classification Table included in Attachment A is adopted and shall apply to the IOUs Grid Modernization Plans for PG&E's TY 2020 and each of the IOU's GRCs filed subsequent to D.18-03-023.

3. The IOUs shall include the common Grid Modernization Classification Table as part of the Grid Modernization Plan with references included to the sections of their GRC, unless the IOUs file a Tier 2 Advice Letter to modify the table 60 days prior to the submission of their GRC Application.

4. The IOUs shall provide reference in their Grid Modernization Plans to all technologies included in the table, which include, but are not limited to, all technologies listed as examples in the Grid Modernization Classification Tables.

5. PG&E and SDG&E shall file Tier 2 supplemental compliance Advice Letters no later than 30 days to add cross-references to their most recent GRC to the Grid Mod Tables.

6. If PG&E has requested funds for utility-owned storage or microgrid switchgear in their TY 2020 GRC, they shall submit errata testimony to include these requests within their Grid Modernization Plan contained in their GRC, Application (A.) 18-12-009.

This Resolution is effective today.

I certify that the foregoing resolution was duly introduced, passed and adopted at a conference of the Public Utilities Commission of the State of California held on March 14, 2019; the following Commissioners voting favorably thereon:

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ALICE STEBBINS

Executive Director

ATTACHMENT A

Revision to Appendix C of D.18-03-023

Description of the Grid Modernization Classification Tables

The following Grid Modernization Classification Tables have been approved as a reference in Resolution E-4982. The tables present several types of classifications, to clarify the relationships of the various technologies needed to integrate DERs into the grid. The classifications are defined in the following columns, and the data in the tables is defined in Attachment B, Classification Definitions.

A. Technology Category: Categories defined in Attachment B, Section A of the Classification Definitions
B. Use Cases: Categorizes technologies based on the three primary objectives for distribution investment, specific to the IOUs' current intent:
    - GDS= Grid and DER Services
    - HDA= High DER Adoption
    - S&R= Safety and Reliability
C. Function: Numbers refer to Appendix B, Part C of the Classification Definitions
D. System-wide or Local Deployment of Technology
E. Distribution System Management Activities and Responsibilities
F. System/ Integration Challenges Addressed: numbers refer to Appendix C, Part F of the Classification Definitions
G. Relevant DERs: DERs that are integrated by the technology category:
    - PEV: Plug-In Electric Vehicle
    - DR: Demand Response
    - DG: Distributed Generation
    - EE: Energy Efficiency
    - ES: Energy Storage
H. Applicable Grid Mod Technologies Related to DER Integration: IOU examples of grid mod technology deployed related to DER integration. This list includes, but is not limited to, the applicable technologies
I. Utility GRC Application Volume and Category: This column shall be filled out by each IOU for their most recent GRC.

DRAFT

Grid Modernization Classification Tables*

A. Technology Category	B. Use Cases	C. Function	D. System wide or Local Deployment	E. Distribution System Management Activities and Responsibilities	F. System/ Integration Challenges Addressed	G. Relevant DERs	H. Applicable Grid Mod Technologies Related to DER Integration	I. Utility GRC Application Volume and Category **
1. Grid Connectivity Model	HDA, S&R, GDS	Circuit modeling, Data Used for Forecasting and DER Value and Solution Analysis	System wide	Distribution Planning, Grid Operations, Market Operations	Items 1 - 8 of list of challenges	EV, DG, ES	Base data layer for ICA, Load and DER forecasting, state estimation, ArcGIS, EDGIS	
2. Grid Management Systems (GMS)	HDA, GDS, S&R	All functions in the definitions, except for DER Value and Solutions Analysis	System wide	Distribution Grid Operations	All items	PEV, DG, ES, DR	Distributed Energy Resource Management System (DERMS), Advanced Distribution Management System (ADMS), Demand Response Management System (DRMS), DER Head-End, and VVO	
3. Long and Short-term Planning Tools	HDA, S&R, GDS	DER Forecasting, DER Valuation Solution Analysis, Circuit Modeling	System wide	Distribution Planning	Thermal, Operational Limitations	EE, DR, EV, DG, ES	Integrated Load and DER forecasting, solution analysis for capacity/reliability, LoadSEER, Power flow modeling and analysis of distribution feeders (CYME) System Modeling Toolset (SMT); Long- Term Planning Tools (LTPT;) Integration Capacity Analysis (ICA), Locational Net Benefit Analysis Tool (LNBA)	
4. Data Sharing Portals	HDA, S&R, GDS	DER Valuation, Solution Analysis, Circuit Modeling	System wide	Distribution Planning	Sustained voltage violations, thermal, protection	EE, DR, EV, DG, ES	Data Sharing Portal (web interface) to publish Distribution Resources Plan data; Distribution Resource Plan External Portal (DRPEP)	
5. Grid Analytics Application	HDA, S&R, GDS	Circuit/System Modeling	System wide	Distribution Planning Grid Operations	Sustained voltage violations, thermal, protection, asset management	EV, DG, ES	Asset management, sensing and measurement (data), improves quality of asset data to improve distribution planning inputs and operational decisions	

A. Technology Category	B. Use Cases	C. Function	D. System wide or Local Deployment	E. Distribution System Management Activities and Responsibilities	F. System/ Integration Challenges Addressed	G. Relevant DERs	H. Applicable Grid Mod Technologies Related to DER Integration	I. Utility GRC Application Volume and Category **
6. Interconnection Processing Tool	HDA, S&R, GDS	Application Assessment and Processing	System wide	Service Planning andCustomer Engagement	Indirect impact on sustain voltage violations, thermal, protection interconnection process)	EV, DG, ES	Customer facing application tosupport streamlining theinterconnection process, improvedistribution planning, Integration Capacity Analysis (ICA)	
7. Adaptive Protection System	S&R	Sensing & Measurement, Data & Device Communications, Control & Feedback Systems, Reliability Management,	Local & System wide	Grid Operations	Protection	All	This is typically incorporated as part of the Common Substation Platform (CSP) at the substation level. In the future, it may be incorporated into ADMS. (Capability in GMS for SCE)	
8. Substation Automation and Common Substation Platform (CSP)	HDA, S&R, GDS	Sensing & Measurement, Data & Device Communications, Control & Feedback Systems, Reliability Management, Cybersecurity	Local & System Wide	Distribution Planning, Grid Operations, Market Operations	Items 1 - 10 of list of challenges	EV, DG, ES	SCADA, coordinated distribution device control with DERs, protection, cybersecurity	
9. Volt/Var Optimization	HDA, S&R, GDS	Sensing & Measurement, Data & Device, Communications Control & Feedback Systems	Local	Distribution Planning, Grid Operations, Market Operations	Voltage fluctuation, sustained voltage violations, Low (Secondary) Voltage Controllers, Conservation Voltage Reduction	EV, DG, ES	Substation Load Tap Changers, Voltage Regulators, Automated programmable capacitor controls, integration with GMS and/or DMS and EMS, future integration with smart inverters	
10. Fault Location, Isolation and Service Restoration (FLISR)	HDA, S&R	Sensing & Measurement, Data & Device Communications, Control & Feedback Systems, Reliability Management	Local	Distribution Planning, Grid Operations, Market Operations	Thermal, Operational Limitations, Fault Location & Service Restoration, Cybersecurity	EV, DG, ES	Remote Intelligent Switches, Augmented Remote Control Switches, Automatic Reclosers, RCS retrofits	

A. Technology Category	B. Use Cases	C. Function	D. System wide or Local Deployment	E. Distribution System Management Activities and Responsibilities	F. System/ Integration Challenges Addressed	G. Relevant DERs	H. Applicable Grid Mod Technologies Related to DER Integration	I. Utility GRC Application Volume and Category **
11. Remote Fault Indicators	S&R	Sensing & Measurement, Data & Device Comms.	Local	Distribution Planning, Grid Operations, Market Operations	Thermal, Operational Limitations, Cybersecurity	EV, DG, ES	Wireless bidirectional fault indicators, providing real time power flow characteristics	
12. Field Area Network	S&R, GDS	Sensing and Measurement, Data & Device Communications, Cybersecurity	Large Local Areas, eventually system wide	Distribution Planning, Grid Operations, Market Operations	Items 1 - 10 of list of challenges	EV, DG, ES	Wireless radios, Routers	
13. Wide Area Network	S&R, GDS	Sensing and Measurement, Data & Device Communications, Cybersecurity	Large Local Areas, eventually system wide	Distribution Planning, Grid Operations, Market Operations	Items 1 - 10 of list of challenges	EV, DG, ES	Fiber optic and IP connectivity	
14. Grid Sensors	HDA, S&R, GDS	Sensing & Measurement, Data & Device Comms.	Local	Distribution Planning, Grid Operations, Market Operations	Thermal, Operational Limitations, Fault Location & Service Restoration, Cybersecurity	EV, DG, ES	Typically, incorporated with other devices/systems such as SCADA reclosers, and FLISR schemes. Telemetry included with the RFIs, RCS retrofits and RISs. This could also include Phasor Measurement Units (PMUs)	
15. Remote Controlled Switches	S&R	Control & Feedback Systems	Local	Distribution Planning, Grid Operations,	Operational Limitations	All	Typically, incorporated with other devices/ systems such as SCADA reclosers, and FLISR schemes.	
16. DER Hosting Capacity Reinforcement	HDA, GDS, S&R	Control & Feedback Systems	Local	Grid Operations	Thermal	All	Installing new manual switches, upgrading sections of cable/ conductor, extending feeder lines to create new ties	
17. Relay Replacement	HDA, S&R	Control & Feedback Systems	Local	System Planning, Grid Operations	Protection	All	Upgrading legacy protection relays on as-needed basis	

A. Technology Category	B. Use Cases	C. Function	D. System wide or Local Deployment	E. Distribution System Management Activities and Responsibilities	F. System/ Integration Challenges Addressed	G. Relevant DERs	H. Applicable Grid Mod Technologies Related to DER Integration	I. Utility GRC Application Volume and Category **
18. Utility-Owned Storage	HDA, S&R	Sensing & Measurement, Control & Feedback, Reliability Management	Local	System Planning and Grid Operations	Voltage Violations, Thermal, Operational Limitations, DER Aggregation Impacts	DR, EV, DG, ES	Energy storage systems installed on the distribution systems to buffer DER output and load (PEV)	
19. Microgrid Interfaces	HDA, S&R	Sensing & Measurement, Control & Feedback, Reliability Management	Local	System Planning and Grid Operations	Voltage Violations, Thermal, Operational Limitations, DER Aggregation Impacts	DR, EV, DG, ES	"Trayer" switches and other hardware and software which allow DER powered microgrids to operate in islanded mode	

Attachment B
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. **Grid Connectivity Model*:** The Grid Connectivity Model represents the fully integrated software database and model of the complete electrical grid containing all electrical and geo-spatial attributes. The Grid Connectivity Model feeds into all other Grid Modernization software tools that utilize grid data to perform planning and real-time operations analysis.[13]

2. **Grid Management Systems (GMS)*:** To support and provide essential functions for grid operators, GMS is envisioned to be a collection of software systems that receives near real-time telemetry from grid devices (including DERs), analyzes the data, and controls the grid devices in order to optimize power flows, respond to fault conditions, or manage microgrids--among many other functionalities. GMS may consist of multiple related software systems, or a single software package that includes all functions, including the Advanced Distribution Management System (ADMS), Distributed Energy Resource Management System (DERMS), Demand Response Management Systems (DRMS), Device Management System, Adaptive Protection System (APS), Volt/VAR Optimization, and Integration Bus Technology (PG&E). The ADMS and DERMS are deeply integrated and comprise the largest components of the GMS. When implemented, the ADMS and DERMS serve as the interface between operators in the control centers and the grid devices, help to manage DERs, control grid assets, and facilitate operations in response to or to prepare for grid events (e.g. planned and unplanned outages and load/generation transfers). From a functional capability perspective, ADMS, and the associated communication and control upgrades, provides real-time situational awareness and analysis, power flow optimization, operational planning, and reconfigurable protection.14 The following systems may be included in Grid Management Systems:

    - **ADMS:** An Advanced Distribution Management System (ADMS) is a software platform that aids Distribution Operators, Engineers, and other personnel in monitoring, controlling, and optimizing the distribution grid to provide safe, reliable, and affordable energy for customers. A DMS is often called "Advanced" if it includes automated applications that leverage the core mapping and DSCADA functionality such as on-line power flow, FLISR, Switch Order Management, VVO, etc.

    - **DERMS:** DERMs can be classified as a software platform that can manage a variety of both aggregated and individual DERs to support various objective

[13] For SCE this model will include the Grid Management System (GMS), System Modeling Toolset (SMT), and Long Term Planning Tools (LTPT). Fore PGE this is Electric Distribution Geographic Information System (EDGIS)
[14] For SCE, ADMS combines the features of SCE's existing Distribution Management System (DMS) and Outage Management System (OMS) and includes enhanced distribution and outage management functions necessary to support the capabilities outlined in SCE's 2018 Grid Modernization testimony related to enhanced communications, planning, and operations.

functions related to grid support, customer value, or market participation. It will enable real-time control and monitoring of DER smart inverters, enabling DERs to minimize grid impacts as well as providing grid services under the right conditions. As an emerging technology, the definition of Distributed Energy Resource Management System (DERMS) technology is still evolving.

- **DRMS:** The IT system that processes enrollments,-registration to the CAISO, management of aggregated resources, dispatch events of PG&E's DR events and retail settlements. DRMS is considered a mature technology.[15]

- **Integration Bus Technology:** The Integration Bus Technology supports integration of multi-vendor systems to facilitate data and control messaging. This provides a flexible, interoperable architecture to support future requirements. In absence of an integration bus, SCE would be required to implement piecemeal fixes that will prove cumbersome to implement and maintain. The GMS can accommodate future enhancements to provide distribution market operations.

3. **Short and Long-Term Planning Tools:** Software tools required for integrated grid planning and time-series forecasting up to a ten-year horizon to identify optimal solutions to system planning challenges. The Planning Tools are capable of importing information from other Grid Modernization software tools that assist with planning activities, thereby producing a single interface for electric system planners.

    - **Long-Term Planning Tools (LTPT)*:** Used by SCE, the LTPT imports data and allows system planners to develop and document both near-term and long-term solutions to grid needs. Software tools required for integrated grid planning and time-series forecasting over a five-to-ten year horizon (with potential reach beyond 10 years, depending on accuracy considerations) to identify optimal solutions to system planning challenges. The Long-Term Planning Tools are capable of importing information from other Grid Modernization software tools that assist with planning activities, thereby producing a single interface for electric system planners. Functions of the tools include distribution infrastructure project portfolio analysis and development (traditional and through DER deferrals), 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 utilizing forecasted circuit configurations.

    - **System Modeling Toolset (SMT)*[16]:** The SMT can be used for near-real time analysis informing short term operational solutions as well as identify forecasted system constraints in the long term. Models multiple levels of the electric system and acts as an interface between transmission and distribution to support analyses including Integration Capacity Analysis (ICA) and interconnection studies. Performs accurate and near-real time analyses of electric system power flows to assist with both planning and operations, providing detailed

[15] U.S. Department of Energy "Modern Distribution Grid Volume II: Advanced Technology Assessment," Version 1.1, March 27, 2017, pp. 33-34

[16] PG&E uses the CYME software platform

information to ensure voltage limits, thermal limits, and protection settings continue to be met as DER penetration increases. This toolset will provide DER applicants expedited information about estimated upgrade costs associated with interconnection requests.

4. **Data Sharing Portal*:** User-friendly, web-based interface that provides customers with immediate access to available information regarding forecasted planning needs, future projects, and circuit interconnection capacities, such as the information included in the Integration Capacity Analysis (ICA), Locational Net Benefits Analysis (LNBA), Grid Needs Assessment (GNA), and Distributed Deferral Opportunity Report (DDOR) required by the Commission in the Distribution Resources Plan (DRP). The Data Sharing Portal will provide transparent planning information to promote customer choice and enable opportunities for DERs as well as streamline the interconnection process.

5. **Grid Analytics Application*:** Software tool that 1) provides a user interface between engineers, operators, and distribution grid planners in using integrated data across multiple software platforms, including smart meter data, weather data, outage data and SCADA data[17], and 2) enables system planners to utilize pre-processed, statistically analyzed data on historical field measurement trends, circuit voltage drop, line transformer utilization, phase identification, operating circuit violations, and accuracy of transformer to meter relationships. This data improves the accuracy of System Planners' long-term electric system planning analyses and modeling, which the planners perform using other Grid Modernization software.

6. **Interconnection Processing Tool*:** Single web-based user interface that provides a common platform for all stakeholders (both internal and external) to interact throughout the interconnection process. More specifically, it allows customers to submit interconnection requests for generation, load, and combinations thereof connecting under any interconnection tariff or connecting as load. Combined with the other Grid Modernization programs.[18]

7. **Adaptive Protection System (APS)***: The Adaptive Protection System, an integrated software system, will work in conjunction with advanced Substation Automation and Distribution Automation programs to evaluate protection settings and schemes on current protection devices based upon real-time system topology and conditions and provide updated relay settings to these devices. This will

[17] Supervisory control and data analysis.

[18] For SCE, the interconnection processing tool can allow customers to track the status of their interconnection application, enables the utility to provide more accurate interconnection responses in a shorter time period, and reduces the backlog of interconnection requests by allowing a single interconnection data and processing location for all internal stakeholders, it is also the system of record across SCE for housing DER data including (but not limited to) contract information and engineering studies.

ensure the devices operate as intended based on current grid topology and operating conditions, supporting adequate and coordinated system protection.[19]

8. **Substation Automation and Common Substation Platform (CSP):** The CSP is a computing platform located in the substation that acts as a control hub, connecting devices in the field to back office systems. The CSP communicates via a suite of technologies such as distribution automation equipment through the Field Area Network (FAN) wireless communication network, and it communicates from the substation to the ADMS and DERMS back office systems through the WAN high speed network. This suite of technologies provides the high speed connectivity needed to give system operators the near real-time understanding of the state of the grid. The CSP computing platform (hardware and software) is designed for two-way communication: to enable secure remote data acquisition from circuit devices (i.e. consumer of data) and provide remote and automatic control over circuit devices (i.e. sender of data). It employs common cybersecurity tools to monitor traffic from FAN and WAN into the substation.[20]

9. **Volt/Var Optimization:** The objective of a Volt VAR Control /Optimization (VVO)[21] systems is to manage voltage and VARs on the system to achieve specific goals, most often voltage /VAR compliance and Conservation Voltage Reduction (CVR). CVR reduces energy usage by lowering service voltages on specific areas of the system with load types that are responsive to CVR, while maintaining overall customer service voltage requirements.[22] VVO allows for greater circuit voltage control as DER behavior changes throughout the day affecting a circuit's voltage profile. VVO is often a centralized automated control system that coordinates substation and field SCADA assets including substation LTCs, voltage regulators, and capacitor banks to optimize voltage and VARs in the system. The system centralizes control of the field and substation capacitors to coordinate and optimize voltage and VARs across all circuits fed by a substation, which indirectly affects low voltage controllerslocated in the secondary voltage portion of the distribution grid. There is also the potential to incorporate low voltage devices with more localized impacts.

10. **Fault Location Isolation System Restoration (FLISR) (e.g. Intelligent Automated Switches):** FLISR technologies and systems involve field hardware, communications systems, and software to automate power restoration and reduce the area and length of power outages by a utomatically isolating the faulted areas re-energizes non-affected customers more quickly and locates trouble areas for field crews to speed restoration. Remote-controlled switches with advanced telemetry

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[19] From SCE's initial research, the above capabilities are not typically provided within an ADMS. The Adaptive Protection System will integrate within GMS to communicate with protective devices throughout the grid.
[20] For SCE, Advanced Substation Automation, particularly SA-3, 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 while providing an avenue for latency reduction.
[21] SCE refers to the system as Distribution Volt VAR Control (DVVC). Volt/Var is a type of optimization performed within the Grid Management System.
[22] Per CPUC Rule 2 criteria for customer allowable voltage limits and ANSI C84.1

provide grid operators with real-time visibility of electric system characteristics such as voltage, current, power flow direction, and fault location information. Installation of remote-controlled switches with advanced telemetry capabilities replaces the ongoing deployment of similar devices that lack these capabilities. These devices are necessary to facilitate outage restoration and enable self-healing circuit capabilities. In addition to providing increased visibility to the grid, these switches and associated automated schemes allow for quick and remote reconfiguration of the distribution system in response to abnormal or emergency situations by having the ability to coordinate with operational systems and/or neighboring devices.

11. **Remote Fault Indicators**: Remote fault indicators (RFIs) are stand-alone grid sensors that provide grid operators with real-time visibility of electric system characteristics such as current, power flow direction, and fault location information. This decreases the time to respond to abnormal conditions, potentially avoiding overload conditions, and reduces customer outage time since field workers can be directed to the faulted line section, reducing their travel and troubleshooting times.

12. **Field Area Network*:** The Field Area Network (FAN) is a wireless communications system that provides connectivity of data and control functions to Distribution Automation (DA) devices, Distributed Energy Resources (DERs), and Commercial and Industrial meters. Components of the FAN include a set of wireless radios and routers that support all the cybersecurity, performance, and operational requirements needed to support current distribution automation assets (once the existing NetComm system is retired), as well advanced Grid Modernization capabilities. These advanced capabilities include automated switching, fault interruption, real-time situational awareness, and reliable integration of non-wires solutions. FAN, along with cybersecurity upgrades, will also provide secure communications between back office control systems and field devices.

13. **Wide Area Network*:** Wide Area Network (WAN) is a historical program of installing fiber optic cable interconnecting substations and control centers to enable real-time data transmission and control functions; and 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. The WAN relies on an internet-based protocol to match the communication protocol of the FAN and enhance cybersecurity via a more robust and secure network. FAN data is backhauled through the WAN with the Common Substation Platform (CSP) providing security services between FAN and WAN.

14. **Grid Sensors:** Equipment capable of providing gathering data such as directional current flow, fault location identification, and voltage at various locations along distribution lines and transmit that data to the distribution control center and grid management systems for near- real time viewing of grid operators and electric system planners. Grid sensors can eventually be incorporated into all devices

installed on distribution lines including but not limited to Intelligent Automated Switches. Remote Fault Indicators are a type of grid sensor.

15. **Remote Controlled Switches:** The first generation of automated switching devices capable of being operated remotely by a grid operator. Remote Controlled Switches (RCS) do not have grid sensing capabilities and are unable to send any distribution system load flow characteristics to grid operations or electric system planners. Capable of minimizing outage time by detecting loss of voltage and operating in a scheme that keeps portions of the circuit energized when experiencing a fault condition.

16. **DER Hosting Capacity Reinforcement:** Grid reinforcement consists of the local upgrades needed to solve distribution needs that arise due to increased DER (e.g., mitigation of overloads, facilitate load balancing, or due to increased DER-hosting capacity needs). The upgrades include installing new manual switches, upgrading sections of cable, or installing conductor to create circuit ties. This could also include upgrades to 4kV substations, including cutovers and eliminations.

17. **Relay Replacement:** Certain protection relay devices may become unreliable under the condition of load encroachment caused by additional DER generation. This is due to the fact that most legacy relaying devices are not equipped to support two-way power flows. Such protective relays may operate incorrectly when experiencing reverse power flow, which would increase equipment outages and increase customer service interruptions. To provide safe and reliable integration of DERs on the system, the protective relaying scheme and related infrastructure on certain circuits ma need to be improved. One option is to upgrade legacy protection relays with new ones. The new microprocessor protection relays are equipped with the capability to provide load encroachment, voltage polarized directional sensing, and ground overcurrent protection. These capabilities can accommodate reverse power flow created by DERs and protect the downstream circuits.

18. **Utility Owned Storage**: Energy storage systems can be installed in substations and on distribution circuits to charge or discharge as needed to smooth the output of PV and the load from PEV charging. SCE and SDG&E have proposed utility owned storage as a mitigation to intermittent renewable energy resources.[23]

19. **Microgrid Interfaces**: Microgrids require hardware and software interfaces with the distribution grid. A switch, for example a "Thayer" switch, is required to isolate the microgrid from the grid and ensure generation from the microgrid generators is connected to the islanded microgrid loads. Software is also required to sense isolation conditions, communicate with the grid operators, and synchronize the microgrid generators. While microgrid demonstration projects are ongoing, SDG&E has requested deployment of microgrids to "alleviate renewable

[23] Ibid, pp. AFC-129 to AFC-133.

intermittency, which allows for increased renewable energy penetration levels and enhanced electric service reliability."[24]

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:** SCE is expected to enable forecasted growth of DERs that is driven by existing tariffs and programs, such as NEM and SGIP. This use case refers to functions and capabilities necessary to safely and reliably plan and operate the distribution system while accommodating the levels of DER adoption anticipated by California's current policies. This use case also refers to enhanced utility tools and processes that streamline and expedite the customer interconnection process. This DER growth consists of customer adoption driven by existing tariffs and programs.

2. **Grid and DER Services:** DERs targeted for specific locations, such as those being piloted in the Integrated Distributed Energy Resources (IDER) Incentives pilot[25] 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. To enable DERs to provide grid services, the distribution planning process should identify opportunities for DERs to defer or avoid traditional capital investments. This use case refers to functions and capabilities needed to enable DERs to provide grid services whereby the DERs provide a specific service to maintain the safety and reliability of the distribution grid. It also refers to functions and capabilities 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 maintain or improve safety and reliability throughout the electric system, independent of DER growth. These investments are required to maintain the safety of the public and field personnel working on the electric system while providing customers with reliable electric service. Although these investments are needed for safety and reliability purposes, irrespective of the levels of DER growth, these investments provide additional benefits by enabling higher DER adoption.

C. Functions of Grid Modernization

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[24] Ibid, pp. AFC-133 to AFC-134.

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

This 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.[26]

1. **DER Forecasting:** DER forecasting refers to estimating future changes in net electrical power flows resulting from increased DER adoption. These forecasts should reflect power flow changes with sufficient temporal and spatial resolutions to support both short-term and long-term planning efforts. 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 forecast DER power flows, including analyzing DER adoption and operational patterns and reviewing DER- related circuit demand changes over time. DER forecasting includes real-time, day-ahead, week-ahead, etc. forecasting to predict net power flow conditions in order to plan appropriately and optimize available grid resources. DER forecasting also includes developing long-term DER power flow forecasts to improve electric system planning accuracy.

2. **DER Value and Solutions Analysis:** DER value analysis refers to estimating the time- and locational-value of DERs. DER values should reflect the benefits DERs provide, including their potential distribution capacity deferral value, as well as the cost of reliably integrating them with the electric system. As referenced in DSPx, "The avoided cost of these 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."[27] DER solutions analysis refers to assessing the potential for DERs to defer traditional upgrades to the distribution system.

3. **Circuit Modeling:** Circuit modeling refers to the representation of real-time and forecasted distribution circuit topology, asset details, load and DER connections, and electrical connectivity (electric system configuration) required to run analysis and simulations for electric system planning and grid operations.

4. **Sensing and Measurement:** Sensing refers to the data collection from devices that measure, track, and record electrical information such as voltage, current, real power, reactive power, and frequency as examples. Measurement refers to the ability to record, track, and compare data to physical reference points in order to understand and determine the current state of any aspect of the electric system. This assists both with real-time grid operations and informs future electric system planning activities.

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[26] More information on DOE's DSPx can be found at https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx/UcLlZ/

[27] U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability, Modern Distribution Grid, Volume I: Customer and State Policy Driven Functionality, p. 53.

5. **Data and Device Communications:** Data refers to various information that is provided by the field devices, including sensors referenced above, to the various software systems for near real-time use or for planning purposes. Device communications refers to the physical infrastructure that transports data to (and takes it from) field devices (e.g. the FAN and WAN).

6. **Distribution Grid Control and Feedback:** This refers to the ability to monitor electric system conditions in near real-time, and to use near real-time data to optimize grid resources devices and electric system configuration by controlling distribution grid assets (including DERs). As described in DSPx under Distribution Grid Controls, coordination and control refers to the signaling and mobilization of distribution grid assets and DERs 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 maintaining or improving safety and reliability.

7. **Reliability Management**: Reliability management refers to the use of near real-time grid data, communications, processes, systems, and procedures to operate the grid safely and reliably. This enables distribution operators to prevent, discover, locate, isolate, and resolve power outages in an informed, orderly, efficient, and timely manner. Technology in this area encompasses many of the grid modernization software and field technologies working in concert, including the Grid Management System, communication infrastructure to transfer data, and the field devices being monitored and operated to ensure optimized grid configuration.

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."[8] Modernizing the grid increases the number of devices an attacker might be able to exploit. New grid applications must be designed with improved cybersecurity controls throughout their lifecycle by integrating strong access controls, secure communications, and secure programming code. Cybersecurity needs to be integrated into each grid modernization component throughout its lifecycle to provide a strong framework against a cyber-attack. SCE employs a defense-in-depth cybersecurity strategy, which uses multiple layers of protection to prevent unauthorized access to its systems.

D. System-wide v. Local Investments

1. **System-wide investments:** System-wide investments provide foundational capabilities that are necessary for enabling all locational grid modernization investments to realize their full benefits. System-wide investments are required to meet the needs of the entire distribution system, which include safety, reliability, and DER integration. These investments primarily include communication systems and

software systems that enable greater visibility to grid operators for real-time grid monitoring and control. These investments also help electric system planners to better model and forecast the needs of the electric system.

2. **Local investments:** Local investments include field equipment installed on the distribution system to meet an identified or forecasted location-specific grid need including, but not limited to, safety and reliability needs or the integration of DERs (e.g. communication equipment for DERs that can be dispatched such as energy storage).

E. Distribution System Management Activities

1. **System Planning:** Distribution system planning involves determining future grid needs based on reviews of historical data, forecasting, electric system capacity analysis, and information sharing activities. These functions require software and analytic tools to analyze historical electric system performance, model electric system topology and equipment, and perform forecasted load flow analysis for the distribution grid. System planning will leverage increasing amounts of granular field data to analyze past, present, and future network models to make accurate decisions about future infrastructure needs while incorporating expected DER performance into safety and reliability analysis to optimize future grid configuration. Examples include the software tools mentioned in Section A above (LTPT, SMT, GAA) that help perform analytic functions such as forecasting the growth of DERs on specific feeders, predicting how those DERs will perform, and determining how those DERs will impact power flows on the grid. Planning technologies serve to benefit the entire system and are foundational to performing critical planning functions.

2. **Grid Operations:** Grid operations technologies enhance operational capabilities to continually assess, monitor, and analyze near real-time data at various circuit locations to manage grid equipment and resources, including DERs, to improve reliability and optimize DERs for customers' and the grid's benefit. Grid operations requires granular visibility of electric system conditions and the ability to reconfigure the distribution grid and dispatch resources. Sensing and monitoring technologies are used to improve visibility of DER performance and the grid's response to changing power flow and outage conditions. Communications technologies transmit this data, allowing grid operators to optimize asset utilization in near real-time. Distribution grid operations technologies encompass both field equipment and software. Field equipment is installed to meet safety and reliability needs in specific locations. Software, including operational forecasting, asset optimization, and distribution system models, are foundational functionalities required to perform grid operations with or without high DER penetration.

3. **Market Operations:** Markets support the provision of grid services for reliably serving load in a manner that maximizes value and minimizes costs while pursuing state policy objectives. Markets currently enable the realization and quantification of the energy and capacity benefits that DERs can provide to the bulk electrical system by enabling the sale of energy, ancillary services, and resource adequacy products to

the bulk electrical system. Market opportunities for DERs at the distribution level are currently under development, largely within the Energy Storage MUA, DRP, and IDER proceedings, with the aim of quantifying and monetizing the local distribution grid benefits that DERs may provide. These distribution markets are expected to promote greater transparency for market participants by identifying locations where DERs could provide the greatest potential benefits, thereby promoting the optimal deployment and dispatch of DERs to satisfy local distribution grid needs, while simultaneously supporting system energy needs. Ultimately, robust market operations are necessary to enable DER benefit stacking. This is necessary to maximize the value DER can provide to the grid, thereby accelerating DER adoption and improving customer choice.

Market operations technologies refer to a suite of integrated software and systems that collectively provide the grid operator with tools and information necessary to optimally dispatch available grid resources. The technologies enable markets to function effectively by incorporating numerous data (demand and behind-the-meter DER forecasts, participating generating resource bids, current grid conditions, planned outages, etc.), to develop optimal, least-cost resource dispatch schedules aimed at maintaining grid reliability. The current ISO market environment determines the dispatch of generating facilities, but future distribution markets could potentially inform the optimal dispatch of not only generation resources, but also distribution grid assets. This would expand least-cost dispatch for reliability purposes to an entirely new suite of electrical assets.

The technologies required to enable these market functions include, but are not limited to, forecasting models (to predict load and non-dispatchable generation), power flow models (to determine grid needs, grid constraints, and the ability of DER capacity to contribute to grid needs), advanced distribution management systems (to provide forecasted and real-time grid condition information), distributed sensing devices (to provide locational-specific information on real power, reactive power, power flow direction, and voltage), aggregation systems (to bundle DERs into meaningful resource clusters for dispatch), outage management systems (to account for grid and asset outages and reduced availability), web portals (for publication of prices, market information, and grid conditions, and to enable energy market participation and capacity auctions), optimization engines (to calculate optimal, least-cost dispatch while maintaining reliability despite grid constraints), distributed energy resource management systems (to monitor and dispatch DERs), communications systems (to monitor and pass instructions to generating facilities), advanced metering infrastructure (to measure resource performance), settlements systems (to compensate generators), and market monitoring (to assure fairness for all market participants).

Many of these systems are "back office" systems deployed for system-wide use. Most of these systems may be deployed in the field or at substations, and thus could be deployed in stages to different locations. However, within a deployment region, all systems must be fully deployed to enable market operations in that region. Ultimately, to maximize effectiveness, these software and field equipment technologies would need to be deployed system-wide.

F. List of Potential System/Integration Challenges

General Issues	Description	Grid Modernization Functional Group	Technologies to Mitigate Challenge[28]
1. Voltage Fluctuation[29]	Distributed generation resources may be randomly intermittent, such as cloud covering a solar panel, thereby lowering their power production and impacting power quality (PQ). This intermittency causes voltage fluctuations and as a consequence, potential flicker in the form of a quick momentary voltage violation.	Distribution Grid Operations	Smart Inverters, Energy Storage, Substation LTCs, Grid Sensors
2. Steady-State Voltage Violations[30]	Steady-state voltage violations may result from distributed generation injecting real power into the circuit, whereby voltage increases. It may also result from loads connecting to the circuit, whereby it decreases voltage. DERs may consequently cause nearby voltages to go above or below set voltage standards, which could damage electrical equipment and impact surrounding customers. This is a particular problem for situations where DER generation exceeds load and produces reverse power flow, which various utility equipment was not built for.	Distribution Grid Operations, Distribution System Planning	Smart Inverters, Load Tap Changers, Voltage Regulators, Capacitors[31], Communication Systems[32], Grid Management Systems, Energy Storage, Reconductoring, Reconfiguration or Addition of Circuits, Remote Switching, Grid Sensors, Energy Storage and Controls
3. Masked Load	Masked load refers to the load on a circuit that is served by customer-sited generation and to which the grid operator lacks real-time visibility. Real-time load data for an entire circuit is	Distribution System Planning, Distribution	Sensors, Grid Management Systems, Communication Systems, Smart Inverters, More granular DER

[28] Examples are not limited to those procured by utilities.

[29] To address voltage issues, utilities have traditionally used voltage regulators, capacitors, and load tap changers. Smart inverters represent a new remedy for managing the voltage concerns at the source 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.

[30] Edited from "Sustained Voltage Violations" to "Steady State Voltage Violations"

[31] Starting in 2011, the CPUC 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.

[32] Communication Systems may include 3rd party communications infrastructure and does not pre-determine that the communication systems are utility-owned

	available to the operator at the substation. On circuits without DERs, this load data is sufficient for operators to estimate load levels along the circuit. On circuits with DERs, however, load is offset by the DER generation, and the operators only see the net load (gross load minus the DER generation). While telemetry at the customer site provides limited real-time generation information, load information from AMI is not available in real-time. So, from the operator's perspective, some load is masked by DER generation such that the operator is unaware that it exists. This limits the grid operators' situational awareness which could limit electric service reliability.	Grid Operations	production information, Remote Switching, Grid Sensors, Short-Term Load-DER Forecasting
4. Thermal[33]	Power flow exceeding device ratings due to the bi-directionality of power flow. This includes power flow stemming from load in one direction and power flow stemming from distributed generation in the opposite direction. This two-way power flow may result in wires and/or transformers exceeding their thermal limits since they were designed for one-way power flow.	Distribution Grid Operations, Distribution System Planning	Substation and Circuit Upgrades, Re-Conductors, Voltage Conversion, local DERMS, Communication Systems, Grid Sensors, Grid Management System, Energy Storage, Remote Switching
5. 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 additional risk outage.	Distribution System Planning, Distribution Grid Operations	Relays, Grid Management Systems, Automation, Communication Systems, Grid Sensors, Remote Switching
6. Operational Limitations	Abnormal conditions or normal operation 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, Remote Switching, Grid Sensors
7. Fault Location and Service Restoration	Utilities are already moving toward automated schemes that restore service more quickly following a fault. These same schemes will also allow some customers to avoid experiencing an	Distribution System Planning, Distribution	Automation, Sensors Technology Platforms, Grid Management System, Communication Systems,

[33] 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.

	outage altogether. With increasing adoption of DERs utilities' grid operations methods need to consider the variation and intermittency of variable resources. This should include considering the output of these resources when determining switching operations to avoid potential operating constraint violations (to avoid a fault). It should also include considering these resources when determining the appropriate switching operations to restore service to as many customers as possible following a fault.	Grid Operations	Grid Sensors, Remote Switching
8. Energy Market Security	The market could be manipulated by a participant with sufficient market power. Market monitoring capabilities are required to provide the tools needed to identify and mitigate security issues, such as insecure market participant transactions.	Distribution Grid Operations, Distribution Market Operations	Technology Platforms, Sensors, Resource Diversity, Grid Management System, Sensors
9. Cybersecurity	The proliferation of DERs that communicate with utility systems presents many more opportunities and vulnerability to cyber threats. This includes DER devices large enough, that if used incorrectly, could damage distribution equipment on the system particularly in ways difficult to restore.	Distribution Grid Operations	Technologies that can Enable IP Based Cybersecurity Protocols, CSP, Substation Automation, FAN, Grid Management System
10. DER Aggregation Impacts on the Bulk Grid	In a world of increasing DERs and customers, the larger grid needs to be able to handle events that occur which could lead to devices reaching their thermal limits causing 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 (will be fixed in the future with smart inverters).	Distribution System Planning, Distribution Grid Operations	Communication Systems, Grid Management System, Smart Inverters, Synchronous Condensers, Static Var Compensators, Remote Switching, DER Headend, Grid Sensors, Curtailment, Negative Pricing, Flex Resources
11. DER Wholesale Market Participation	Growth of DERs responding to wholesale energy and ancillary service market dispatches have the potential to create distribution level voltage and capacity violations without new tools and processes.	Distribution System Planning, Distribution Grid Operations	System Modeling, Short and Long- Term Forecasting, Grid Management Systems, DERMS, DER Headend, Communication Systems

(END OF APPENDIX C)