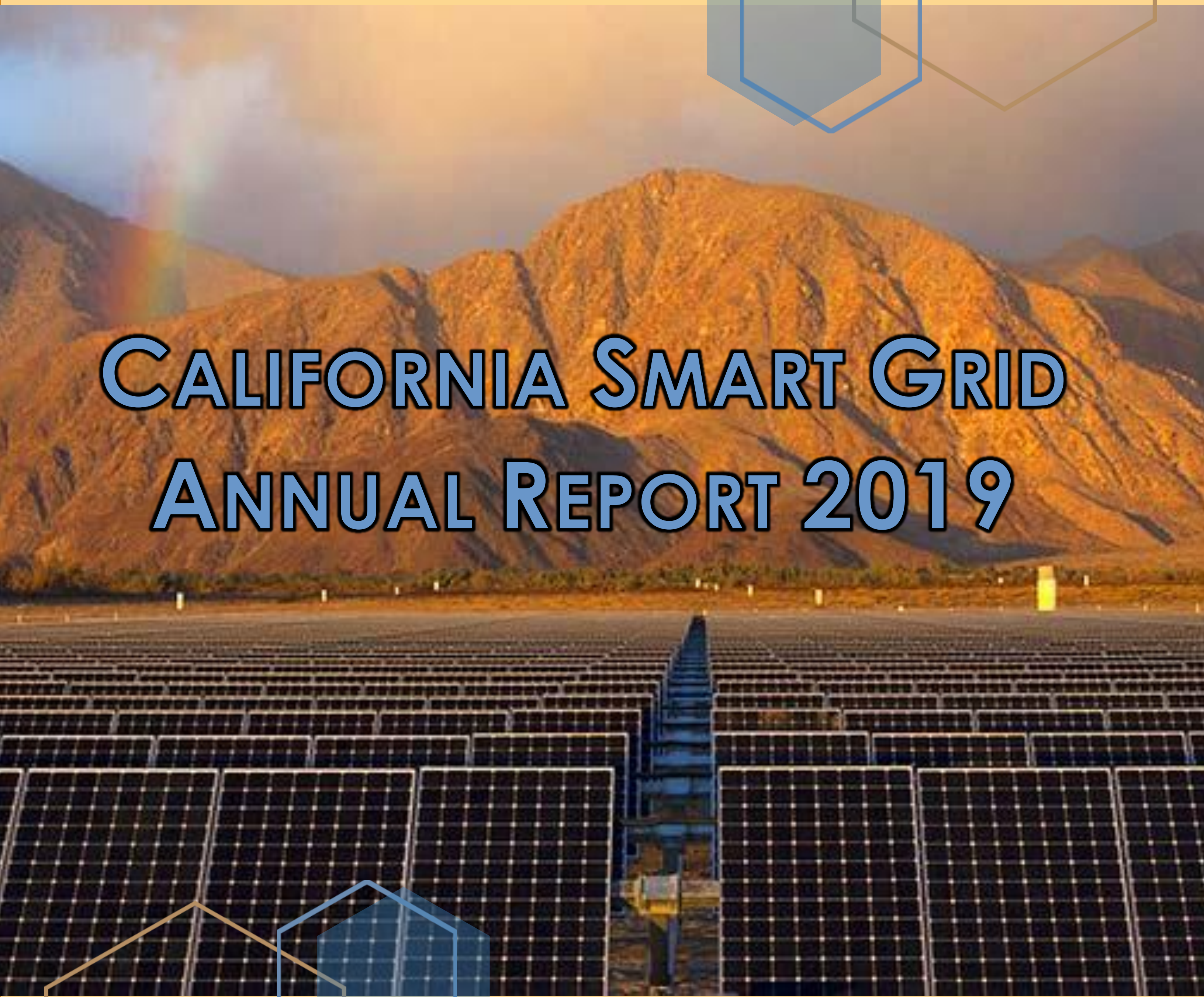
California Smart Grid Annual Report 2019



California Public Utilities Commission

CALIFORNIA SMART GRID ANNUAL REPORT TO THE GOVERNOR AND THE LEGISLATURE

February 2020

About This Report

Each February, the California Public Utilities Commission is required to report to the Legislature and Governor on the progress made in the past year towards achieving the State's Smart Grid Goals. This Annual Report complies with Public Utilities Code § 913.2.

Principal Author

Jonathan Frost – Analyst, CPUC Energy Division

Contributors

Sophie Meyer – Utilities Engineer
David Lee – Utilities Engineer
Audrey Neuman – Analyst
Joyce Steingass – Utilities Engineer
Jose Aliaga-Caro – Utilities Engineer
Robert Peterson – Analyst
Jean Lamming – Analyst
Brian McCollough – Analyst
Michael Castelhano – Analyst
Kanya Dorland – Analyst
Katherine Stockton – Analyst
Gabriel Petlin – Supervisor, Grid Planning and Reliability Section, CPUC Energy Division

On the Cover: Borrego Springs Microgrid in Borrego Springs, California. Photo courtesy of the National Renewable Energy Laboratory.

CONTENTS

TABLES AND FIGURES

1. EXECUTIVE SUMMARY

This Annual Report on California's Smart Grid activities provides an overview of the California Public Utility Commission's (CPUC's or the Commission's) recommendations for a Smart Grid. It also reviews the plans and deployment of Smart Grid technologies by the state's three largest electric investor-owned utilities (IOUs or the utilities),[1] and the IOUs' estimates for the costs and benefits to ratepayers.[2]

This report will detail the following:

- CPUC Smart Grid-related activities in 2019 (Section 3.1);
- CPUC Smart Grid activities that are expected in 2020 (Section 3.2); and
- IOU Smart Grid project reports and overall ratepayer costs and benefits. (Section 4).

California Smart Grid Report – Key 2019 Developments

In 2019, the CPUC continued to make progress towards creating a safer, greener, more efficient and more reliable electric grid through:

- Approving additional energy storage to defer several utility infrastructure investments, to mitigate reduced natural gas deliverability, and to meet long-term capacity needs.
- Crafting a policy framework to promote microgrids and resiliency strategies to help make communities more resilient in the face of the growing threat of wildfires and other natural disasters.
- Developing policies and technical standards and approve utility pilot programs to facilitate higher penetrations of distributed energy resources (DERs) and electric vehicles.
- Approving additional demand response (DR) to shift electricity use away from peak consumption hours and extending the Demand Response Auction Mechanism (DRAM) to facilitate future utility DR contracts.

[1] The three largest California IOUs are Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E).

[2] "…the commission shall report to the Governor and the Legislature on the commission's recommendations for a Smart Grid, the plans and deployment of Smart Grid technologies by the state's electrical corporations, and the costs and benefits to ratepayers." (Pub. Util. Code § 913.2).

Highlights of the 2019 CPUC Smart Grid-related activities include:

- **Distribution Resources Plan (DRP)** – The three electric IOUs published geospatial data portals that provide information from their Distribution Investment Deferral Framework (DIDF) 2019 cycle filings and Interconnection Capacity Analyses (ICA). Also in 2019, the CPUC Energy Division published a white paper that proposed methods for estimating the value of deferring distribution and transmission infrastructure investments with DERs. The CPUC approved over 16 megawatts (MW) of PG&E battery storage contracts that are deferring several planned capital investments in grid infrastructure. The CPUC also approved the launch of two DIDF solicitations scheduled for January 2020 where SCE and PG&E will seek DER offers to defer several planned grid infrastructure investments totaling $54.8 million.
- **Microgrids –** To implement Senate Bill (SB) 1339 (Stern, Chapter 566, Statutes of 2018), the CPUC initiated a rulemaking focused upon crafting a policy framework to facilitate the commercialization of microgrids and development of resiliency strategies. In addition, the CPUC staffed a new Resiliency and Microgrids Section to develop and implement energy policy in support of SB 1339. The Resiliency and Microgrids Unit convened an initial Microgrids Order Instituting Rulemaking (OIR) Workshop in December 2019. CPUC Staff transmitted its Track 1 Staff Proposal making recommendations to address issues that could be mitigated by Summer 2020, such as streamlining interconnection processes, modifying existing tariffs to maximize resiliency benefits, and facilitating local government access to utility infrastructure data to support development of resiliency projects.
- **Interconnection Rule 21** – The Rule 21 Working Group Three submitted its final report in July 2019 for CPUC action on the following issues: interconnection upgrade timelines and costs, interconnection application portal improvements, the interconnection of electric vehicles, and smart inverter issues, In August 2019, the CPUC authorized the formation of a Vehicle-to-Grid Alternating Current (V2G AC) Interconnection subgroup – a joint effort with the transportation electrification proceeding – to develop safety standards for the interconnection of electric vehicles that utilize an internal on-board inverter.
- **Smart Inverters** – In July 2019, the CPUC issued Resolution E-5000,[3] which provided guidance on implementation of the smart inverter Phase 2 communications requirements (Phase 2) and of select Phase 3 advanced functions (Phase 3). In August 2019, the Smart Inverter Working Group (SIWG)

[3] Resolution E-5000 is accessible through the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M309/K713/309713654.PDF.

reconvened to develop recommendations for final implementation plans for the smart inverter Phase 2 communications requirements and select Phase 3 advanced functions, which will allow the grid to support additional distributed generation while contributing to grid stability.

- **Energy Storage** – The CPUC approved over 211 MW of new IOU storage procurement in 2019. The largest procurement was driven by two needs: 1) to help address electrical system operational limitations resulting from reduced gas deliverability caused by the partial shutdown of the Aliso Canyon natural gas storage facility; and 2) to contribute to meeting long-term local capacity requirements (LCR) in the Moorpark sub-area of the Big Creek/Ventura local reliability area. The CPUC approved other storage procurements to satisfy distribution deferral objectives where the storage may serve as a non-wire alternative (NWA) to a traditional distribution infrastructure investment.
- **Transportation Electrification** – Through continued efforts to implement Senate Bill (SB) 350 (De León, Chapter 547, Statutes of 2015), the CPUC approved utility programs and pilots at all three of the large IOUs and small multi-jurisdictional utilities, totaling approximately $166 million in 2019. This brings the total spending that the CPUC has approved over the past few years for transportation electrification to more than $1.3 billion. The CPUC is currently considering another $803.5 million in utility proposals for additional transportation electrification investment programs.
- **Demand Response (DR)** – The CPUC approved a four-year extension of the DRAM and ordered several design changes to improve DRAM performance. The CPUC refined technical aspects of DR integration into CAISO markets, including the adoption of new baseline methods. The CPUC implemented a prohibition on use of fossil fuel generators during DR events. The CPUC scoped into a dynamic rate proceeding consideration of pilots that would shift flexible loads to reduce the evening ramp, integrate excess renewable generation, provide cost savings to customers and grid operators, and lower greenhouse gas emissions. The Federal Energy Regulatory Commission (FERC) supported a CPUC decision that gives the CAISO more flexibility in dispatching emergency DR. Finally, the CPUC approved a 14 MW long-term DR contract procured through an all-source solicitation.

- **Enhanced Reliability Reporting** -- Enhanced reliability reporting supports the State's grid modernization efforts by increasing transparency into the reporting metrics for reliability standards and by requiring the IOUs to publicly describe the remediation efforts they plan to take to address the worst performing circuits. In 2019, the utilities reported reliability metrics that were largely better than the national average. For instance, national average for outage duration per customer was 100.5

minutes per customer, while Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) reported 99.6, 71.3 and 77.8 minutes per customer respectively.

- **Customer Data Access** –The click-through authorization process, released in 2018, allows customers to easily share their energy related data with third-party demand response providers of their choice, has been used over 137,725 times by residential and commercial customers.[4] Regional planners are now also able to target energy programs in geographical areas in order to help combat climate change with the release of Energy Atlas 2.0 geospatial tool in August 2019.

[4] Information about the number of authorizations and service accounts processed by the IOUs click-through processes was taken from the IOUs compliance filings pursuant to D.15-03-042, Ordering Paragraph 1, Quarterly Reports to Track Progress of Rule 24 and Rule 32 implementation (Quarterly Rule 24/32 Reports) for March 2018, June 2018, September 2018, December 2018, March 2019, June 2019, and September 2019.

2. INTRODUCTION

2.1. WHAT IS THE SMART GRID?

The Smart Grid, as defined in the State of California by Senate Bill 17 (Padilla, Chapter 327, Statutes of 2009), is a fundamental change in the existing electricity infrastructure that utilizes advances in technology to create a safer, greener, more efficient, and more reliable electric grid.[5,6] The objectives in California, per SB 17 and Pub. Util. Code § 8360, are to promote:

- Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid;
- Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security;
- Deployment and integration of cost-effective distributed resources and generation including renewable resources;
- Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources;
- Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation;
- Integration of cost-effective smart appliances and consumer devices;
- Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in-electric and hybrid-electric vehicles, and thermal-storage air conditioning;
- Development of functions that provide consumers with timely information and control options;

[5] Per the IEEE (Institute of Electrical and Electronics Engineers), Smart Grid refers to the use of digital communications and control technology and new energy sources, generation models, and adherence to cross-jurisdictional regulatory structures to provide an objective collaboration, integration, and interoperability between computational and control systems, generation, transmission, distribution, customer, operations, markets, and service providers.

[6] Please see the following link for the SB 17 Bill text: http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200920100SB17.

- Development of standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid; and
- Identification and lowering of unreasonable or unnecessary barriers to adoption of Smart Grid technologies, practices, and services.

2.2. CALIFORNIA'S CONTINUAL GRID MODERNIZATION

The CPUC has worked with the California IOUs and the Legislature on numerous fronts throughout 2019 to advance grid modernization. The resulting initiatives are oriented towards making the grid in California smarter, safer, and better able to accommodate higher penetrations of DERs, while reducing carbon emissions and improving reliability and resiliency. Recent grid modernization efforts have built upon smart meter[7] deployment, cost reductions in digital control and communications technology, power electronics, and advanced automation technologies that improve customer reliability and grid resilience.[8] The accelerating adoption of customer-side intermittent renewable generation, primarily solar photovoltaic (PV) systems, is producing new operational challenges and opportunities for the grid, and is driving the current need for IOU investment in Smart Grid technologies. The CPUC and the IOUs are prioritizing modernizing grid infrastructure such that it serves as a beneficial platform rather than an impediment for customer adoption of DERs so that DERs can be interconnected to the grid in a "plug-and-play" manner.[9]

A planned approach to increase Smart Grid investments is required to increase grid reliability and to reduce safety risks that may be driven by increasing levels of DER penetration on the grid from customer adoption of DERs and IOU traditional distribution investment deferral with DERs. The Distribution Resources Plan proceeding (R.14-08-013)[10] currently underway has been guiding new Smart Grid investment requests in future general rate cases (GRCs)[11] to meet these safety and reliability challenges.[12] The DRPs require the IOUs to begin planning and investing in the distribution system in a way that will enable higher levels of DER adoption than traditional grid planning processes have previously allowed. DERs have the potential to

7 Smart meter refers to modern electrical meters that can transmit customer energy consumption information directly to the utility through its cellular network on a frequent schedule, so the utility does not need to send a person to obtain this information.

8 Reliability is measured in number of outages and outage duration. IEEE Standard 1366 defines the following reliability metrics: Customer Average Interruption Duration Index (CAIDI), System Average Interruption Frequency Index (SAIFI), and System Average Interruption Duration Index (SAIDI).

9 Creating a distribution grid that is "plug-and-play" involves dramatically streamlining and simplifying the processes for interconnecting to the distribution grid to create a system where high penetrations of DER can be integrated seamlessly.

10 Please see the following link to the R.14-08-013 Order Instituting Rulemaking: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M103/K223/103223470.pdf.

11 General Rate Cases are regulatory proceedings used to address the costs of operating and maintaining the utility system and the allocation of those costs among customer classes for a given IOU.

12 Pursuant to P.U. Code § 769, CPUC Rulemaking (R.) 14-08-013 is considering the IOUs' DRPs.

improve reliability and resiliency, particularly for essential emergency-response and disaster-recovery services.

The CPUC is working diligently to address all aspects of creating a modern grid for California. Established in 2016, the DER Action Plan was created to capture the CPUC's vision for enhancing DER adoption in order to support the CPUC's directives related to rates and affordability, climate change, environmental sustainability, economic prosperity, and coordination with other governmental entities. The DER Action Plan serves as a roadmap for decision-makers, staff, and stakeholders working in support of California's DER future in order to facilitate proactive, coordinated, and forward-thinking development of DER-related policy.[13] As of early 2020, approximately 80-90 percent of the DER Action Plan had been achieved.

2.2.1 DEPLOYMENT PLAN BACKGROUND

The Commission adopted several Decisions to further the state policy of Grid Modernization through implementation of the Smart Grid Proceeding (R.08-12-009)[14], including D.10-06-047, which requires the IOUs to annually file Smart Grid Deployment Plans (Annual Reports).[15] The three IOUs filed their initial Deployment Plans on July 1, 2011, as required by SB 17.[16] The Commission approved the Deployment Plans in D.13-07-024[17] on July 25, 2013. This approval cleared the way for implementation of the Deployment Plans as part of each IOU's GRC. Furthermore, D.13-07-024 adopted template criteria for the Smart Grid Annual Reports that the IOUs are required to file annually to demonstrate progress on Smart Grid deployment.

Through successive Decisions, the Smart Grid Proceeding ordered the utilities to:

- Deploy smart meters and provide downloadable usage data to customers and authorized third parties, referred to as Customer Data Access (CDA);
- File Smart Grid Deployment Plans and to set the requirements for what the plans must address;
- Protect the privacy and security of customer data generated by smart meters;

[13] The DER Action Plan is accessible through the following link: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Commissioners/Michael_J._Picker/DER%20Action%20Plan%20(5-3-17)%20CLEAN.pdf.
[14] Please see the following link to the R.08-12-009 Order Instituting Rulemaking: http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/95608.PDF.
[15] For the full text of D.10-06-047, please see the following link: http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/119902.PDF.
[16] Please see the following link for the SB 17 Bill text: http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200920100SB17.
[17] Please see the following link for the full text of D.13-07-024: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M075/K390/75390046.PDF.

- Provide Home Area Networks (HAN) capability on the smart meters;
- Adopt metrics to measure the effectiveness of smart grid investments; and
- Convene an Energy Data Access Committee to determine ongoing access policies and issues.

In 2014, the Commission closed the Smart Grid Proceeding R.08-12-009[18], and ordered the IOUs' Smart Grid Deployment Plans to include the following eight elements:[19]

1. Smart Grid Vision Statement
2. Deployment Baseline
3. Smart Grid Strategy
4. Grid Security and Cyber Security Strategy
5. Smart Grid Roadmap
6. Cost Estimates
7. Benefits Estimates
8. Metrics

Per the direction of D.10-06-047, the IOUs have filed their Smart Grid Deployment Plans in October of each year since 2012 and are required to so through October 1, 2020. The IOUs filed their 2019 Smart Grid Annual Reports in October 2019.[20]

2.2.2 SMART GRID COSTS AND BENEFITS

The CPUC requires the three major IOUs to report on Smart Grid program costs and associated benefits. The costs and benefits are shown in Table 1. Table 1. IOU Costs and Benefits for Fiscal Year July 1, 2018 through June 30, 2019 reflect the reporting period for the IOUs' Smart Grid Annual Reports.[21] Costs are calculated as the sum of all the Smart Grid programs and investments implemented by each IOU. Benefits are calculated as a sum of avoided cost of utility operations, including environmental, customer service, and Transmission & Distribution (T&D) costs, as well as reliability, physical and cybersecurity benefits, and

[18] Please see the following link to the R.08-12-009 Order Instituting Rulemaking: http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/95608.PDF.
[19] From Decision (D).14-12-004, which is accessible through the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M143/K563/143563016.PDF.
[20] The 2019 annual reports, as well prior annual reports, can be found on the CPUC website at: http://www.cpuc.ca.gov/General.aspx?id=4693.
[21] The IOUs were ordered to report data in alignment with the State's Fiscal Year which corresponds with July 1, 2018 to June 30, 2019.

demand response savings realized in a fiscal year.[22] Each IOU has a different approach to calculating the Smart Grid costs and benefits. The data presented in Table 1 is shown as it was reported to the CPUC by the IOUs. This data is not suitable for direct comparison between the IOUs as they rely on different methodologies for estimating benefits.[23] See Section 4.1, **Error! Reference source not found.**, for additional detail.

Table 1. IOU Costs and Benefits for Fiscal Year July 1, 2018 through June 30, 2019

IOU	Smart Grid Costs ($Millions)	Smart Grid Benefits ($Millions)	Avoided Outage Minutes
PG&E	$253.73[24]	$200.27	87.2 Million
SDG&E	$133.5	$99.9	3 Million
SCE	$115.38	$659.3[25]	239 Million

2.2.3 ONGOING COMMITMENT TO IMPROVING SAFETY AND RELIABILITY

The CPUC is committed to maintaining and improving the safety, reliability, and economic value of the electric supply, as well as to reducing the environmental impact of electricity production, transmission, and distribution.

Pursuant to the goals of Assembly Bill 66 (Muratsuchi, Chapter 578, Statutes of 2013)[26] which directed the IOUs to improve electric system reliability through greater accountability and enhanced reporting, the CPUC issued a Decision in January 2016[27] that required reliability reporting on a more local basis by the

[22] Benefits may include those accrued from previously completed projects and does not include all the benefits that may be realized over the lifetime of the projects. Some Smart Grid projects may not have direct benefits but may enable other programs or technologies that will provide benefits in the future.

[23] In past GRCs the calculation of reliability benefits has been reviewed in some utilities' GRCs, but for the purpose of this report, this data is included as utilities reported it to the Commission and has not been vetted.

[24] Of this total, $99.8 million of the costs incurred this past reporting year is represented by the cumulative costs of one distribution automation and reliability project (Distribution Substation SCADA Program), and one transmission automation and reliability project (Modular Protection Automation and Control Installation Program).

[25] According to SCE, its reliability benefits are driven by its distribution automation program which was deployed two decades ago and continues to accrue benefits. In 2019, SCE estimated that its distribution automation technologies allowed SCE to avoid 239 million customer outage minutes. SCE updated its Value of Service (VOS) estimates, which calculate the cost of outages, and assigned a value of $2.63 per customer minute of interruption (CMI). By multiplying $2.63 per CMI and 239 million customer outage minutes, SCE estimated a savings of $628.57 million from avoided outage minutes which represents 90% of the total $659.3 million benefits SCE reported. (SCE Smart Grid Deployment Plan Annual Report, p.8). The CPUC cannot attest to the accuracy of SCE's VOS or avoided outage minutes estimates.

[26] For the full text of AB 66, please see the following link: http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB66.

[27] D.16-01-008 in R.14-12-014. See the following link for the full text of D.16-01-008 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M157/K724/157724560.PDF.

IOUs. The IOUs were also directed to report annually on the top one percent of their worst-performing circuits and to detail their investment plans for mitigating these reliability deficiency issues. Several Smart Grid technologies deployed by the utilities, such as Geographic Information Systems (GIS) and Outage Management Systems (OMS), are expected to be deployed to mitigate reliability concerns and to automate and improve outage detection while improving reporting.

As the result of the CPUC's commitment to making safety an integral consideration in all its proceedings, the utilities, in Fiscal Year 2018-2019, refined their safety risk assessments in their 2019 Wildfire Mitigation Plans, SCE's Grid Safety and Reliability Plan, and the IOUs' GRCs. By identifying, prioritizing, and offering mitigations for their top safety and operational risks, the utilities are providing the CPUC with a stronger rationale for considering proposed GRC investments in infrastructure upgrades, improved training, and safer operations. In their GRCs, the IOUs have identified wildfire safety to be among their top priorities. Increasingly, mitigation proposals involve new Smart Grid technologies that enhance safety, reliability, and resiliency and improve monitoring of both grid and pipeline operations and distributed energy resources.

The CPUC also focuses on resiliency. Unlike reliability, which is well-defined with specific quantitative metrics, resiliency is an emerging Smart Grid attribute. Resiliency includes the ability of the electric system to resist failure, to reduce the magnitude and/or duration of outage events, and the ability to recover from these events. Improving the ability of the system to restore operations fully from a high-stress situation or event is one of the objectives of many CPUC Smart Grid initiatives. Grid modernization initiatives generally enable the utility to develop situational awareness that anticipates problems using automated fault location technologies and smart meters. Such information and technologies contribute to maintaining a more resilient grid by reducing the frequency and duration of outages and enabling microgrids to operate in island mode.[28]

Given the rising frequency of catastrophic wildfires in California and the present-day use of proactive Public Safety Power Shut-offs (PSPS) to reduce the incidence of utility equipment-caused wildfires, the need for smart grid technologies to enhance safety, reliability, and resiliency is ever more paramount. The CPUC and the utilities have prioritized the following wildfire mitigation pathways to guide their investments and to reduce the negative impacts of PSPS over the next several years:

[28] Island mode refers to when a circuit or microgrid operates in isolation from the distribution grid and can continue to serve power through DERs when the distribution grid experiences outages and can no longer serve the circuit or microgrid.

1) Reducing Fire Ignitions
    a. Grid hardening –
       Includes installing covered conductors and steel poles, and selective undergrounding of distribution and transmission lines that are currently mounted on wooden poles and towers.
    b. Proactive operational practices –
       Such practices include remote disabling of reclosing devices by using supervisory control and data acquisition (SCADA) technology (described further in Section 4.2.2 SDG&E Example Projects) and PSPS as a last resort to reduce the risk of vegetation-related ignitions.
    c. Enhanced vegetation management –
       Includes clearing overhanging branches directly above or near powerlines to a 12-foot radius and removing trees that are among the highest risk for vegetation-related fires and trees that have the potential to hit powerlines if they fall.
    d. Asset inspection and maintenance –
       Includes increasing above ground asset inspection with aircraft (including drones) and crews on the ground and using GIS and advanced metering infrastructure (AMI) data to monitor facilities for signs of failure.

2) Reducing Fire Spread
   The IOUs are installing hundreds of weather stations and high-definition cameras, utilizing satellites, granular weather forecasts, remote sensing technologies, monitoring fuel moisture and running models to predict weather and possible wildfire behavior. The utilities are also staffing wildfire safety operations centers and PSPS emergency operations centers around the clock during fire season.

3) Reducing the Number of Customers Impacted by PSPS
   This includes using distribution sectionalizing/segmentation devices, transmission line switching, and deploying microgrids and backup generation.

4) Reducing PSPS Outage Durations
   The IOUs aim to reduce the amount of time for restoration post-PSPS event. PG&E, for instance, aims to cut its restoration time in half for the next fire season.

5) Reducing PSPS Frequency
   The IOUs aim to obtain enhanced meteorological data to guide PSPS decision-making and to refine the PSPS boundaries. They seek to install further segmentation devices, microgrids and additional grid hardening materials so that they can reduce the frequency of PSPS outages in the future.

3. COMMISSION ACTIVITIES RELATED TO SMART GRID IN 2019

3.1. 2019 SMART GRID ACTIVITIES

3.1.1 DISTRIBUTION RESOURCES PLANS

Pub. Util. Code §769[29] required the IOUs to file Distribution Resource Plans (DRPs) by July 1, 2015. In the IOUs' Distribution Resource Plans submitted in 2015, the CPUC required the IOUs to propose contracts, tariffs or other DER procurement mechanisms to maximize the locational benefits and minimize the incremental costs of distributed resources. The CPUC also required the utilities to identify additional spending necessary to integrate DERs into distribution planning, to modernize their electric grids, and to identify the barriers to the deployment of DERs. The CPUC's overarching goals within this framework are to lower incremental cost of forecasted DERs, to minimize grid impacts, to reduce barriers to DER deployment, and to target DER deployment to avoid or defer planned utility distribution investments. Because California's climate targets require electrification of the transportation sector by 2045, DERs play an important role in mitigating load growth on the distribution system and on transmission in load-constrained areas, which is necessary to limit the costs of meeting California's climate targets.

The CPUC's DRPs align with the State's Smart Grid goals of grid modernization, which includes greater customer choice (in terms of facilitating behind-the-meter DER deployment), improved communications systems, and higher levels of automation, all of which can also accommodate two-way energy flows.[30] Many of the projects and activities envisioned as part of the DRP support a smarter, cleaner grid in which customer-sited DERs not only supply power to the customer's own load but also to other customers on the grid.

The CPUC instituted the Distribution Resources Plan Proceeding, R.14-08-013[31], to consider the IOUs' 2015 DRP Applications across the following three tracks:

[29] Pursuant to Assembly Bill 327 (Perea, Chapter 611, Statutes of 2013).
[30] Traditional distribution system planning practices, in which the IOUs planned the system for one-way power flows emanating from centralized power generation, are undergoing dramatic changes as a result of the requirements of Pub. Util. Code § 769.
[31] Please see the following link to the R.14-08-013 Order Instituting Rulemaking: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M103/K223/103223470.pdf.

Track 1: Analytical/Methodological Issues

This Track is focused on developing the methodologies for two analyses that identify optimal locations for DER deployment; the analyses were adopted in D.17-09-026[32] and implemented in 2018:

1. *Integration Capacity Analysis*: The ICA determines the available hosting capacity of every distribution circuit in the IOUs' service territories to accommodate additional DERs. The ICA helps DER developers site projects in grid locations that are less likely to trigger system upgrades and are used by the IOUs in the annual distribution planning process to identify proactive upgrades to increase a given area's hosting capacity in light of forecasted DER adoption. The ICA is intended to streamline the Rule 21 interconnection process.
2. *Locational Net Benefits Analysis*: The LNBA is used by the IOUs to determine optimal locations for DER deployment based on cost-effective opportunities for DERs to defer or avoid traditional distribution system investments. LNBA results are used to identify candidate distribution investment deferral opportunities in annual IOU filings as part of the DIDF process described under Track 3, below. The LNBA will reflect the benefits of DER deployment, relative to traditional infrastructure. This information also informs DER sourcing activities being determined in the Integration of Distributed Energy Resources and Integrated Resource Planning Proceedings (R.14-10-003 and R.16-02-007 respectively).[33,34]

Track 2: Demonstration (Demos) and Deployment Projects

Under DRP Track 2, the IOUs sought to implement projects with the aim of 1) proving the ability to defer traditional infrastructure projects with DERs and 2) managing the distribution system with increasingly higher DER penetrations. Track 2 of the DRP concluded in 2019, and most activity concluded prior to 2019. Activities in 2019 included:

Demo D (Operate the system at high penetrations of DERs): This project called for the utilities to integrate high penetrations of DER into their distribution operations, to demonstrate the operations of multiple DERs in concert, and to coordinate operations with third parties and

[32] For the full text of D.17-09-026, please see the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M196/K747/196747754.PDF.

[33] For the full text of the R.14-10-003 Order Instituting Rulemaking, please see the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M116/K116/116116537.PDF.

[34] For the full text of the R.16-02-007 Order Instituting Rulemaking, please see the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K663/158663325.PDF.

customers. In 2017, this project was approved for PG&E and SCE in D.17-02-007[35] and D.17-06-012[36]. PG&E's Demo D DER solicitation was unsuccessful, because it did not receive cost-effective DER bids. SCE's Demo D concluded in 2019. after SCE determined that the Demo could not be completed because field testing could not be performed due to cybersecurity challenges. SCE, though, obtained valuable information, such as the design, development, and testing of new control and communication systems for the electric grid.

Demo E: Plan and operate a microgrid. This project will demonstrate a microgrid where DERs (both customer- and utility-owned) serve a significant portion of customer load and reliability services. Furthermore, it will demonstrate the use of a DER management system (DERMS), which is a software solution that monitors, controls, and optimizes both third-party- and utility-owned DERs. In 2017, the CPUC approved this project for SDG&E and SCE in D.17-02-007 and D.17-06-012, respectively. SCE's and SDG&E's Demo E concluded in 2019. SCE's Demo E is described in more detail in the Microgrid section on page 17. SDG&E utilized an existing microgrid for this project, the Borrego Springs microgrid. SDG&E successfully conducted multiple islanding events which disconnected the microgrid from the main distribution electric grid with no power interruption to the customers. However, SDG&E encountered challenges islanding when utilizing a third-party owned photovoltaic plant; thus, SDG&E was able to island the Borrego Springs microgrid for only a short period of time.

Track 3: Policy Issues

In Track 3 of the DRP, the CPUC addressed policy questions related to incorporating new tools and forecasting methods into existing distribution system planning and investment processes that the CPUC adopted in 2018:

1. **DER Growth Scenarios and Distribution Load Forecasting**: In D.18-08-004, the CPUC considered the methodological issues for developing circuit-level forecasts of DER adoption and distribution load to inform distribution planning, as well as to support process alignment with the California Energy Commission's (CEC) Integrated Energy Policy Report (IEPR), IRP, Long-Term Procurement Planning (LTPP), and the CAISO's Transmission Planning Process (TPP).[37] Each year the IOUs disaggregate the

[35] For the full text of D.17-02-007, please see the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M176/K178/176178449.PDF.

[36] For the full text of D.17-06-012, please see the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M190/K737/190737689.PDF.

[37] For the full text of D.18-08-004, please see the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M221/K552/221552166.PDF.

CEC IEPR forecast for load and DER down to the circuit level in order to support their August filing of the Grid Needs Assessment (GNA).

2. **Grid Modernization Investment Framework**: In D.18-03-023, the CPUC adopted a framework for identifying and evaluating which utility investments in grid modernization are necessary to integrate cost-effective DERs into distribution planning and which will also yield net benefits to ratepayers.[38] With the expansion of DERs, many new technologies have emerged that work to integrate DERs into grid planning and operations. The Grid Modernization Framework guides CPUC GRC decision-making to help determine the necessary investments to the distribution grid that will yield net ratepayer benefits while supporting a modern grid that supports high penetrations of DERs and maintains safety and reliability. In May 2019, the CPUC issued D.19-05-020 which approved $159.2 million in capital and $11.57 million in operations and maintenance expenditures for Grid Modernization for SCE's 2018 Test Year GRC.[39]
3. **Distribution Investment Deferral Framework:** The DIDF was established in 2018 by D.18-02-004.[40] DIDF is a planning framework for identifying, evaluating, and selecting opportunities for DERs to defer or avoid traditional distribution investments and produce net ratepayer benefits. The IOUs implemented the framework in 2018 and 2019. The IOUs submit an annual Grid Needs Assessments and Distribution Deferral Opportunity Report (DDOR) in August of each year, followed by a six-week Distribution Planning Advisory Group (DPAG) stakeholder process to help screen and vet which planned grid investments are best suited for deferral by DERs via competitive solicitations. Each November, the IOUs file advice letters seeking approval to launch DIDF request for offers (RFOs) for specific deferral projects.

To date, SCE has contracted for DERs for two deferral projects. The CPUC has approved four PG&E contracts for DERs for deferral projects. In December 2019, the CPUC approved three new PG&E contracts for energy storage projects totaling 14 MW which will defer $13.5 million in grid

---

[38] See the following link for the text of D.18-03-023: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M212/K432/212432689.PDF.

[39] Please see the following link to the full text of D.19-05-020: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M293/K008/293008003.PDF.

[40] The solicitation framework and key underpinning of the IOUs' annual Grid Needs Assessment and Distribution Deferral Opportunity Report filings are established in the Competitive Solicitation Framework from Decision D.16-12-036 (here: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M171/K555/171555623.PDF) and implemented in the DRP by Ruling on 11/19/18 (here: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M240/K044/240044803.PDF).

investments. To date, SDG&E has not had any deferrals. The latest round of proposed deferral projects shows an increase in the volume of projects that will go to DIDF RFO in 2020.[41] SCE will seek offers to defer six planned investments that were estimated to cost a total of $36.2 million. PG&E will seek offers to defer one investment in January 2020 ($3.6 million) and two to three additional investments later in 2020 (up to $15 million). The total value of the ten SCE and PG&E investments to be deferred by DERs is $54.8 million.

3.1.2 MICROGRIDS

The CPUC has developed policies to facilitate the deployment of distributed energy resources located within the IOUs' distribution systems. Recognizing that microgrids may support California's policies to integrate a high concentration of distributed energy resources on the electric grid, the Legislature passed SB 1339 (Stern, 2018), which added Sections 8370, 8371, and 8372 to the Public Utilities Code. These new Sections 8370-8372 are intended to facilitate both the commercialization and interconnection of microgrids.[42]

At its September 12, 2019 Commission meeting, the CPUC initiated the OIR Regarding Microgrids Pursuant to SB 1339 and Resiliency Strategies, R.19-09-009, to consider how to implement the requirements of SB 1339. The scoping memo issued in December 2019 organized the proceeding into three tracks. Track 1 will develop resiliency plans in areas prone to outage events and wildfires, with the goal of putting some microgrid and other resiliency strategies in place by Spring or Summer 2020 and policy framework to facilitate the commercialization and interconnection of microgrids.[43] Therefore, the issues within scope of Track 1 are:

1. Prioritizing and streamlining interconnection applications to deliver resiliency services at key sites and locations;
2. Modifying existing tariffs to maximize resiliency benefits;
3. Facilitating local government access to utility infrastructure and planning data to support the development of resiliency projects; and
4. Investor Owned Utility proposals for immediate implementation of resiliency strategies, including

[41] The solicitation framework and key underpinning of the IOUs' annual Grid Needs Assessment and Distribution Deferral Opportunity Report filings are established in the Competitive Solicitation Framework from Decision D.16-12-036 (here: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M171/K555/171555623.PDF) and implemented in the DRP by Ruling on 11/19/18 (here: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M240/K044/240044803.PDF).

[42] For the full text of Public Utilities Code Sections 8370, 8371 and 8372, please see: https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB1339.

[43] For the full text of the Microgrid OIR, see: docs.cpuc.ca.gov/PublishedDocs/Published/G000/M314/K274/314274617.PDF.

partnership and planning with local governments.

In Track 2 of the Microgrids OIR, the CPUC will focus on developing standards, protocols, guidelines, methods, rates, and tariffs to support and reduce barriers to microgrid deployment statewide, while prioritizing system, public, and worker safety, and avoiding cost shifts between ratepayers. Track 3 will consider the ongoing implementation requirements of SB 1339 as well as any future resiliency planning. Track 3 will include:

1. Forming a working group to codify standards and protocols needed to meet IOU and CAISO microgrid requirements;
2. Developing a standard for direct current metering in Electric Rule 21 to streamline the interconnection process and lower interconnection costs for direct current microgrid applications, including net energy metering paired with storage systems and microgrids; and
3. Removing the waiver of fees for projects that do not provide resiliency.

Other 2019 Microgrid Activities:

CPUC Staff attended the April 26, 2019 public workshop regarding microgrids funded by the CEC's Electric Program Investment Charge (EPIC) program to monitor and become informed about lessons learned from CEC's experience with 20 microgrid demonstration projects. The EPIC demonstration projects have a total of 30 sites in the California IOU service territories. The IOUs' 2019 microgrid-related activities are described in detail below.

Pacific Gas and Electric Microgrid Activities

PG&E submitted a Track 1 proposal in R.19-09-009 to address immediate resiliency strategies for outages. Its proposal seeks authorization for three programs:

1. Make Ready Program involving infrastructure upgrades that would enable a subset of distribution substations deemed as high priority to operate as distributed generation enabled substations that would operate as microgrids.
2. Temporary Generation Program that would reserve third party mobile generators for deployment during public safety power shut-offs to provide power for:
    a. Energizing safe-to-energize distribution substations which are not yet configured for permanent distributed generation under PG&E's Distributed Generation Enabled Microgrids initiative;
    b. Energizing safe-to-energize substations using temporary interconnections;

c. Supplying energy for temporary microgrids such as mid-feeder microgrids serving critical facilities or community commercial corridors;

d. Providing backup power as a last resort to specific critical facilities to support continuity of service during public safety power shut-off events such as fire departments, county emergency services, medical facilities, water treatment plants, and major transportation routes.

3. Community Microgrid Enablement Program to provide a framework that would provide utility technical support to enable local communities' efforts to initiate community microgrid solutions.

PG&E is developing Resilience Zones where PG&E can safely provide electricity to community resources by isolating the area from the wider grid (islanding the area) and re-energizing it using mobile generation during an outage. PG&E's Resilience Zone approach had been operationalized in at least two locations (Angwin and Calistoga) as of October 2019 while a total of 40 Resilience Zone locations were proposed in PG&E's General Rate Case filing.

PG&E's Resilience Zones are:

- Hardened, central subset of the local electric distribution system that serves "Main Street" (central business district);
- Can be quickly (within 1 hour) isolated/islanded from the broader grid during PSPS events by on-site PG&E workers;
- Powered with mobile generators using a pre-installed interconnection hub for rapid energization;
- Cost approximately $1 million each not including site preparation costs.

PG&E intends to install remote grids in lieu of overhead pole lines, where cost effective. For example, this solution may be feasible in portions of Butte County that are being rebuilt following the 2018 Camp Fire. In the design phase, remote grids are presently described as stand-alone, self-sufficient grids powered by solar, battery energy storage, and propane generators or other technologies, to serve small electric distribution systems. The sites are chosen based on risk evaluation and cost analysis, with consideration of mitigation options such as:

- Proactive de-energization of power lines (PSPS);
- Undergrounding;

- Hardening in place (e.g., wood to steel poles, covered conductors).

Southern California Edison Microgrid Activities

SCE intends to initiate a 2020 Public Safety Power Shut-off Microgrid Project according to its Track 1 Proposal submitted in R.19-09-009. Based on a screening approach that considered circuits involving 2019 public safety power shut-offs, SCE has selected six shortlisted locations. The utility will seek vendor proposals in mid-to-late February 2020 and targets final decisions on microgrid projects with vendor contract execution in March 2020.

SCE provided a report for Demonstration Project E ("Demo E") in the DRP Proceeding.[44] In its report, SCE concluded that it cannot complete Demo E because SCE was unable to incorporate design and implementation of necessary and appropriate cybersecurity controls with the demonstration technologies within the project timeframes. The SCE Demo E project was intended to demonstrate operations and coordination of multiple DERs managed by a dedicated control system. The Demo E project also aimed to demonstrate capabilities to serve as the system operator of a microgrid using customer and SCE-owned DERs. SCE stated the cybersecurity threat environment that Demo E was slated to operate in had evolved, necessitating additional cybersecurity controls to minimize risks to the grid production systems.

San Diego Gas and Electric Company Microgrid Activities

In its Track 1 submittal to R.19-09-009, SDG&E reported that it has several microgrid projects that could potentially be in-service by end of 2020 based upon CPUC authorizations of its 2019 Wildfire Mitigation Plan. These projects involve microgrid installations proposed for Cameron Corners, the Ramona Air Attack Base, and Desert Circuit 221.

SDG&E's proposed Cameron Corners Microgrid Project would consist of renewable resources (725 kW photovoltaic modules) and 500 kW storage to serve about 1,700 customers who SDG&E identifies as disproportionally impacted by PSPS events or other outages. Additionally, SDG&E will be seeking CPUC authorization for a field level microgrid controller which is a software and hardware solution that enables the distribution grid operator to monitor, manage and control the

component resources of the microgrid.

SDG&E's second proposal in the Microgrid OIR would install electrical infrastructure and electrical vehicle

[44] Southern California Edison Company's (U 338-E) Demonstration Project E Final Status Report, Consistent with Appendix A of Decision (D.)17-02-007.

("EV") charging stations at critical facilities within the microgrids that SDG&E is deploying in anticipation of the 2020 fire season. This charging infrastructure would mitigate customer mobility issues arising from a public safety power shut-off ("PSPS"), including emergency evacuation.

In its Energy Storage Procurement application, SDG&E proposed microgrid energy storage projects within the distribution grid, which provided some multiple-use applications, including microgrid islanding for selected critical public sector facilities. Although the CPUC did not deem the results of the request for proposals reasonable in CPUC D.19-06-032, the CPUC authorized SDG&E to use the previous results in a future Application seeking approval of specific projects that better address the requirements of Assembly Bill 2868 (Gatto, Chapter 681, Statutes of 2016).[45]

Liberty Utilities

In its 2019-2021 GRC Application, Liberty Utilities proposed to install a microgrid in Olympic Valley and an 8 MW/32 MWh battery electric storage system (BESS) within a village in nearby Placer County. The system is comprised of 72 Tesla Powerpack 12 systems (each of which has 210 kWh of energy storage capacity) and 4 Tesla bi-directional inverters. In the event of a specific outage condition, this BESS will automatically activate and provide vital back-up power to all Liberty CalPeco customers reliant on those circuits for power. Liberty states that the BESS will provide up to 8 MW of electricity for four hours. In addition to back-up power, it would increase system reliability in the region; provide for the integration of additional renewable energy resources; and allow for system peak shaving, energy shifting, voltage regulation, and demand response.

PacifiCorp

PacifiCorp's October 2019 Application, A.19-10-003, proposed reallocation of remaining California Solar Initiative Program funding to support emergency service resiliency programs: 1) conduct technical feasibility studies and/or fund the capital costs to enable the installation of battery storage systems at facilities offering critical services during emergencies; and 2) deploy portable renewable generators for emergency responders.[46]

[45] For the full text of AB 2868, please see the following link: https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160AB2868.

[46] Please see the following link to the full text of PacifiCorp's A.19-10-003: https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/california/filings/docket-a-19-10-003/10-1-19-application/PacifiCorp_Emergency_Services_Resiliency_Programs_Application.pdf.

3.1.3 INTERCONNECTION

The Rule 21 tariff sets interconnection, operating, and metering requirements for generation facilities connecting to a utility's distribution system in order to maintain safety and reliability of the distribution and transmission systems. Barriers to the deployment of distributed resources are addressed in the CPUC's Interconnection Rulemaking, R.17-07-007[47]. In 2018, the Interconnection Rulemaking considered policy and programmatic changes to streamline the interconnection process. The March 2018 Working Group One Report[48] addressed urgent interconnection issues. The October 2018 Working Group Two Report[49] leveraged work on the ICA from the utility DRP Proceeding R.14-08-013[50] to further streamline the Fast Track process[51] in Rule 21. Working Group Three addressed 1) planning, construction, and billing of distribution upgrade issues, 2) application processing and review issues, 3) smart inverter issues and coordination with the Integrated Distributed Energy Resources proceeding, and 4) the interconnection of electric vehicles, from December 2018 through early 2019. The July 2019 Working Group Three Report outlined the consensus and non-consensus items across the eleven interconnection issues scoped for the group to consider. The CPUC will consider the Working Groups' recommendations in forthcoming decisions.

In August 2019, the CPUC authorized the formation of a Vehicle-to-Grid Alternating Current Interconnection subgroup in R.17-07-007 (to consider streamlining interconnection of distributed energy resources and improvements to Rule 21) and R.18-12-006 (to continue the development of rates and infrastructure for vehicle electrification) to discuss and identify existing standards to fulfill safety requirements for the interconnection of a mobile inverter housed inside the electric vehicles. The establishment of the subgroup in both proceedings will ensure broad applicability of the subgroup's efforts.

The sub-group launched in September 2019 and a final subgroup report was filed in both proceedings in December 2019. The subgroup's recommendations will be considered in a forthcoming Decision on the

---

47 For the full text of the R.17-07-007 Order Instituting Rulemaking, please see the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M192/K079/192079467.PDF.

48 The R.17-07-007 Working Group One Report is accessible through the following link: http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/Infrastructure/RDI/itcn/R1707007WorkingGroupOneFinalReport.pdf.

49 The R.17-07-007 Working Group two Report is can be found on in the following webpage: http://www.cpuc.ca.gov/General.aspx?id=6442455170.

50 Please see the following link to the R.14-08-013 Order Instituting Rulemaking: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M103/K223/103223470.pdf.

51 The Fast Track process is a streamlined review process that is based on multiple evaluation screens for interconnecting net energy metering, non-export, and small exporting facilities.

Working Group Three Report. The safety standards developed through the V2G AC Interconnection subgroup will facilitate future transportation electrification programs and create policies.

3.1.4 SMART INVERTERS

Inverters convert Direct Current (DC) to Alternative Current (AC) power and are essential for interconnecting various DERs, including solar PV systems (which produce DC power), to the grid. Smart inverters provide capabilities beyond those of a standard inverter—autonomous response to voltage and frequency conditions, safety features, and communications capabilities—and are one of the foundational building blocks of the Smart Grid. Smart inverters' primary benefit is to increase the capacity of the distribution system to accommodate higher penetrations of DERs. Smart Inverters accomplish this by mitigating some of the grid impacts of intermittent variable resources and enhancing these same DERs' ability to serve as grid assets. They also have the potential to improve operation of the grid through advanced communications and control. Under the CPUC's direction, the SIWG has developed inverter functionality recommendations that are being incorporated into the Electric Rule 21 tariffs. These recommendations are grouped into three phases: Phase 1 describes seven autonomous smart inverter functions, Phase 2 defines smart inverter communications requirements, and Phase 3 outlines eight advanced smart inverter functions. The Phase 2 communications requirements and Phase 3 advanced functions represent higher levels of DER dispatch and control capabilities which are necessary for leveraging DERs for grid operations. Once operationalized, these functions will increase the amount of DER generation that the grid can accommodate without infrastructure upgrades and will increase grid safety and stability.

As of September 9, 2017, the IOUs incorporated seven autonomous Phase 1 smart inverter functions into their Rule 21 tariffs and made these Phase 1 functions mandatory for all inverter-based DERs interconnecting under Rule 21, pursuant to CPUC D.14-12-035and R.11-09-011. [52,53] The Phase 2 Smart Inverter communications requirements were added to Rule 21 in April 2017, and it is expected that these capabilities will become mandatory in 2020. Once these requirements are adopted, all inverter-based generation interconnecting under Rule 21 will be capable of communication and the Institute of Electrical

[52] For the full text of R.14-12-035, please see the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M143/K827/143827879.PDF.

[53] For the full text of R.11-09-011, please see the following link: http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/144161.PDF.

and Electronics Engineers (IEEE) standard 2030.5[54] will serve as the default protocol used by IOUs to communicate to either individual DERs, energy management systems, or DER aggregators. These communications, when operationalized, will increase utility visibility into grid conditions and allow DERs to respond to shifting grid needs.

In April 2018, the CPUC approved revisions to Rule 21 that incorporate smart inverter Phase 3 advanced functions. The CPUC also adopted Reactive Power Priority, which is a powerful tool for preventing and mitigating voltage rise on the distribution system. Reactive Power Priority became mandatory in June 2018. Throughout late 2018 and early 2019, the SIWG developed a plan to implement smart inverter Phase 2 communications requirements as well as Phase 3 advanced functions such as "Scheduling Power Values and Modes."

In February 2019, SIWG stakeholders formally requested that the CPUC clarify and amend the Phase 2 and 3 requirements to allow for smoother implementation. The CPUC responded to this request and, in July 2019, issued additional implementation clarifications through Resolution E-5000.[55] In August 2019, the SIWG recommenced bi-weekly meetings to finalize the implementation plan for the smart inverter Phase 2 communications requirements and to select Phase 3 advanced functions.

3.1.5 ENERGY STORAGE

The CPUC's energy storage procurement policy was formulated with three primary goals:

1) Grid optimization, including peak reduction, contribution to reliability needs, or deferral of transmission and distribution upgrade investments;
2) Integration of renewable energy; and
3) Greenhouse gas (GHG) reductions in support of state targets.

In response to Assembly Bill (AB) 2514 (Skinner, Chapter 469, Statutes of 2010), the CPUC established energy storage targets in 2013 of 1,325 MW to be procured by 2020 and to be operational by 2024.[56] In 2019, the CPUC approved over 211 MW of energy storage. To date the CPUC has approved procurement of more than 1,746.95 MW of new storage capacity to be built in the state, of this total 506 MW are operational. The AB 2514 mandate is procured in three distinct grid domain targets with some flexibility

[54] Also known as Smart Energy Profile (SEP) 2.0 Application Protocol Standard.
[55] Resolution E-5000 is accessible through the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M309/K713/309713654.PDF.
[56] For the full text of AB 2514, please see the following link: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200920100AB2514.

between the grid domain targets. Cumulatively the utilities have exceeded the 1,325 MW target and satisfied nearly all domain-specific requirements. See Table 2 below for more detail including the grid domains and targets.

Table 2. IOU Progress Towards the AB 2514 Energy Storage Target (MW)

	Grid Domains	Storage procurement mandate (AB2514) target	Mandate driven storage procurements	Other storage procurements	Total Storage procurement to date	Current excess/ deficiency relative to storage mandate	Adjusted excess/deficiency, per CPUC counting rules
PG&E	Transmission	310	135	557	692	382.00	235.75
	Distribution	185	36	16.95	52.95	(132.05)	0.00
	Customer-side	85	36	10	46	(39.00)	(39.00)
SCE	Transmission	310	0	120	120	(190.00)	0.00
	Distribution	185	27	293	320	135.00	0.00
	Customer-side	85	100	219	319	234.00	135.00
SDG&E	Transmission	80	-	110	110	30.00	30.00
	Distribution	55	-	57	57	2.00	2.00
	Customer-side	30	-	30	30	0.00	0.00
	IOU Total	**1325**	**334**	**1412.95**	**1746.95**		

CPUC Data as of January 2020.

The utilities have procured energy storage to meet local capacity requirements and is a focus of distribution planning, deferral, and other services. Thus, energy storage is emerging as a crucial backbone of the Smart Grid and is increasingly selected as a reliability resource of choice.

The CPUC is implementing AB 2868, which allows for the procurement of up to 500 MWs of additional distribution-connected energy storage, with up to 25% behind the utility meter. On June 27, 2019, through D.19-06-032, the CPUC approved PG&E's proposed AB 2868 procurement plan for up to 5 MWs of behind the meter thermal storage with a spending cap of $6.4 million.[57] However, D.19-06-032did not approve SDG&E and SCE's proposed AB 2868 procurement programs.

[57] Please see the following link for the full text of D.19-06-032: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M309/K522/309522481.PDF.

In D.19-12-055, the CPUC approved an application filed by SCE in A.19-04-016 for a 100 MW energy storage resource that will contribute to meeting long-term LCR requirements in the Moorpark sub-area of the Big Creek/Ventura local reliability area.[58] SCE also procured 95 MW of energy storage in the same area to support the same LCR needs while also addressing electrical system operational limitations resulting from reduced gas delivery caused by the partial shutdown of the Aliso Canyon natural gas storage facility. In both procurements, the expectation of relatively quick commissioning of the energy storage resources was key in selecting storage to meeting these reliability needs.

In Northern California, the CPUC approved a distribution deferral project for PG&E consisting of 2.75 MW of energy storage.[59] The project was procured through the DIDF process and will be located at the Gonzales substation.

3.1.6 TRANSPORTATION ELECTRIFICATION

In order to help reduce greenhouse gas emissions below 40 percent of 1990 levels by 2030 and to help achieve carbon neutrality by 2045,[60] the State of California aims to have 5 million light-duty[61] zero emission vehicles on the road by 2030 and 250,000 electric vehicle charging stations operational by 2025.[62] To date, there are approximately 655,000 light-duty zero emission vehicles on the road in California. Beginning with the Smart Grid Proceeding, R.08-12-009, the CPUC began exploring the potential for plug-in electric vehicles (PEV) to interact with an increasingly modernized grid. The CPUC's activities related to PEVs are broadly categorized into four areas:

1) Charging infrastructure deployment
2) Determining Rates
3) Vehicle-grid integration
4) Designing rebates and incentives

In December 2018, the CPUC issued a new OIR (R.18-12-006) regarding Transportation Electrification, called the Development of Rates and Infrastructure for Vehicle Electrification (DRIVE) OIR, which directed the utilities to develop EV rates that are affordable and beneficial to the grid and directed staff to

---

[58] Please see the following link for the full text of D.19-12-055: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M323/K464/323464733.pdf.
[59] The CPUC approved this project by approving PG&E's Advice Letter 4002-E.
[60] See Governor Edmund (Jerry) Brown's Executive Order B-55-18 to Achieve Carbon Neutrality for more information https://www.gov.ca.gov/wp-content/uploads/2018/09/9.10.18-Executive-Order.pdf.
[61] Light-duty refers to passenger vehicles (cars and light trucks) and all other vehicles under 8,500 pounds.
[62] See Governor Edmund (Jerry) Brown's Executive Order B-55-18 to Achieve Carbon Neutrality for more information https://www.gov.ca.gov/wp-content/uploads/2018/09/9.10.18-Executive-Order.pdf.

develop a framework to guide future IOU investments in Transportation Electrification.[63] In response, CPUC staff will release the Transportation Electrification Framework (TEF) in early 2020. The TEF directs the IOUs to develop ten-year plans for their transportation electrification investments, addressing, among other topics, certain cross-cutting issues; needed upgrades to the electrical grid to support PEVs; managing charging load; and alignment with other planning processes like the IRP, DRP, and those at the CEC, CAISO, and CARB.

In 2019, the CPUC approved a new PG&E commercial time-variant EV rate, designed to manage the grid impacts of commercial EVs while reducing burdensome demand charges. This decision also directed PG&E to submit an application for a dynamic commercial EV rate, to better account for grid impacts in the future. In 2019, SDG&E also applied for an EV commercial rate, which the CPUC is currently reviewing. SCE and Liberty Utilities continue to offer their own commercial EV rates while PG&E, SCE, SDG&E, and Liberty Utilities each continue to offer EV time-of-use energy rates for residential customers to encourage off-peak EV charging. SDG&E also offers a dynamic EV rate for those that use charging infrastructure deployed in their Power Your Drive program which is described in more detail in **Error! Reference source not found.** on page 41 of this Report.[64] SDG&E is also implementing a Public Grid Integrated Rate for use at DC fast charging stations the utility owns, and Bear Valley is implementing an EV Pilot Rate.[65]

In 2019, the CPUC worked extensively with CARB, the IOUs, publicly owned utilities, and other stakeholders to establish a statewide point-of-purchase PEV rebate program, the Clean Fuel Reward. SCE is authorized to be the short-term administrator of this program. The CPUC required that all IOU customers receiving the rebate must also receive rate education. The dealership experience is a pain point for selling PEVs. This program is an opportunity to educate customers and vehicle dealers about how to best charge an EV by taking advantage of rates that save the customer money and benefit the grid. The program is expected to launch in 2020.

In 2019, the CPUC also authorized several new charging infrastructure programs including: pilots for schools and beaches across the three large IOU territories, a medium- and heavy-duty electrification program in SDG&E's territory, and a pilot program called EV Empower to provide residential chargers to low- and medium-income customers in PG&E territory. Each of these programs considers grid impacts through rates.

---

[63] Please see the following link to the full text of the R.18-12-006: http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=252025566.

[64] In SDG&E's dynamic rate, prices change in response to expected hourly grid conditions.

[65] Through this rate, SDG&E directly passes the TOU rate signals through to the customer to encourage off-peak charging.

The CPUC authorized SDG&E,[66] SCE,[67] and PG&E[68] to deploy up to 13,500 charging stations at multi-unit dwellings, workplaces, and some public locations. [69]

A 2012 settlement between the CPUC and NRG – a large American energy company that was connected to the 2000 California Energy Crisis – directed NRG to spend $102.5 million to deploy infrastructure to support the same location sectors as the IOU programs above, public DC fast charging, pilot programs for research and development (R&D), and to support underserved communities.[70] In addition to some of the load management strategies described above, the NRG Settlement is also testing vehicle-to-grid technologies and energy storage integration as load management strategies.

The CPUC, along with other state agencies, is developing policies that support Vehicle-Grid Integration (VGI), which is discussed further in the interconnection section 3.1.3 of this report.

3.1.7 DEMAND RESPONSE

In response to Energy Division's 2019 Demand Response Auction Mechanism (DRAM) Evaluation Report, the CPUC adopted D.19-07-009 in A.17-01-012 et al. approving a four-year extension (2020-2023) to the DRAM with a budget of roughly $55 million.[71] The DRAM provides a primary pathway for third-party DR providers and their customers to receive capacity payments for providing load shedding services during periods of peak electricity demand and high prices. D.19-07-009 adopted the following goal for DRAM:

> To help California meet its environmental objectives, cost-effectively meet the needs of the grid, and enable customers to meet their energy needs at a reduced cost while spurring innovation and growth of a competitive third-party market.[72]

D.19-07-009 also established critical design changes intended to improve performance and reliability of DRAM resources. A working group, formed by CPUC order, submitted a report recommending further

[66] For more information see D.16-01-045.
[67] See D.16-01-023 for more information.
[68] See D.16-12-065 for more information.
[69] The actual amount of deployed infrastructure will almost certainly be lower than 13,500, however the final charging station count is not yet known since the IOUs are either still implementing or concluding these pilots.
[70] For more information about the CPUC/NRG settlement agreement, please see the following link: http://www.cpuc.ca.gov/General.aspx?id=5936.
[71] For the full text of D.19-07-009, please see http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M309/K713/309713644.PDF.
[72] D.19-07-009, p. 38.

improvements to the design, operation and performance of DRAM for CPUC consideration. In December 2019, this was addressed in D.19-12-040, which also closed the proceeding.[73]

The CPUC's D.19-07-009 adopted four out of five wholesale baseline methods approved by FERC for the DRAM settlement process. These new methods are expected to ease some of the challenges posed by the interaction between the wholesale and the current retail baselines for calculating customer performance during DR events.

As of January 1, 2019, and in line with the state's focus on reducing GHG emissions, the CPUC has prohibited the use of customer-owned fossil fuel generators during DR events and launched an associated verification mechanism. In late 2019, the utilities completed a study to assess the effectiveness of various devices in detecting customers' compliance with the prohibition.

The Load Shift Working Group released a report in January 2019 with six proposals for pilots that would incentivize customers to shift flexible loads like space heating and cooling, electric vehicle charging, industrial processes, and agricultural pumping to periods of high renewable generation and low GHG emissions, which in the CAISO system tend to correspond with low or negative prices. These pilot concepts and other proposals were under consideration in 2019 in SDG&E's GRC Application, A.19-03-002.

In April 2019, the FERC accepted the CAISO's request to revise regulations to allow implementation of CPUC D.18-11-029, which confirmed that reliability-based demand response resources (RDRR) can be used anytime within the CAISO Warning Stage without any additional conditions.[74] These revisions to Section 34.7 at FERC, increased the flexibility available to CAISO for utilizing this resource to potentially alleviate an imminent grid emergency condition.

The Supply Side Working Group, established in D.17-10-017, submitted their final report in June 2019 with recommendations on technical refinements to the January 2018 integration of all demand response programs into the CAISO wholesale markets.[75] The report weighed in on issues including CAISO requirements for telemetry and the need to investigate less costly technologies to address the expensive telemetry requirement for resources greater than 10 megawatts; for minimum availability to be eligible for local area capacity credit through the CPUC's Resource Adequacy program, and for must-offer obligations.

[73] Please see the following link for the full text of D.19-12-040: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M322/K796/322796293.PDF.
[74] The full text of D.18-11-029 is available through the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M248/K670/248670669.pdf.
[75] Please see the following link for D.17-10-017: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M198/K319/198319901.PDF.

Finally, in late 2019 the CPUC approved Southern California Edison's long-term contract for 14 MWs of residential battery-backed DR to serve capacity-constrained local areas.

3.1.8 ENHANCED ELECTRIC RELIABILITY REPORTING

Enhanced electric reliability reporting provides an objective standard and information to foster continuous improvement of reliability. Pursuant to the goals of AB 66,which directs the IOUs to improve electric system reliability through greater accountability and enhanced reporting, the CPUC issued D.16-01-008 in January 2016 that required reliability reporting on a more local basis by the IOUs.[76,77] The IOUs were also directed to report one percent of their worst-performing circuits and to annually detail their investment plans for mitigating these reliability deficiencies. Several smart grid technologies deployed by the utilities, such as Geographic Information Systems (GIS) and Outage Management Systems (OMS), are expected to be further deployed to mitigate reliability concerns and to automate and improve outage detection while improving reporting.

CPUC D.16-01-008 directed the utilities to use an enhanced reliability reporting template to report reliability data to the CPUC on July 15 of each year beginning in 2017.[78] Reliability data is reported at the system level as well as division or district level.[79] D.16-01-008 requires the IOUs to identify and report on their worst performing circuits based on two or three years of repeat poor performance according to quantified reliability metrics. The three IOUs report one percent of their worst-performing circuits, while PacifiCorp, Liberty Utilities, and Bear Valley Electric Service report their top three worst performing circuits, respectively and combine their reporting into a single report for the CPUC.

D.16-01-008 also allows customers to request reliability information about their circuits via utility websites and receive responses in a timely manner. All the IOUs will conduct at least one annual public in-person town hall and webinar presentation about the information in their annual electric reliability reports. Furthermore, in compliance with D.16-01-008, the IOUs developed a joint proposal to consolidate

[76] For the full text of AB 66, please see the following link: http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB66.

[77] See the following link for the full text of D.16-01-008 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M157/K724/157724560.PDF.

[78] The Electric System Reliability Annual Reports can be found on the CPUC website at: http://www.cpuc.ca.gov/General.aspx?id=4529.

[79] Electric utilities divide their service territories into either Divisions or Districts. Each Division or District consists of groups of electric circuits.

different reliability-reporting requirements from CPUC Decisions and General Orders into a single reporting framework. The IOUs are expected to further refine their proposal in 2020.

In 2018, the IOUs reported below the national median electric reliability performance for duration per customer, but the IOUs' duration per event was above the national median based on the U.S. Energy Information Administration (EIA) Annual Electric Power Industry Report.[80] This report detailed data from a) 823 electric companies that reported duration of outages and from b) 757 electric companies that reported frequency of outages.[81]

Table 3 below compares the electric reliability indices of Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) with the national electric reliability indices median values.

Table 3. IOU Electric Reliability Compared to the U.S. National Median Values for 2018

Reliability Measure \ Utility	Nation (Median)	PG&E	SCE	SDG&E
Duration per Customer (Minute/Customer)	100.5	99.6	71.3	77.8
Frequency per Customer (Event/Customer)	1.1	.96	0.7	0.6
Duration per Event (Minute/Event)	93.4	103.9	99.5	123.8

Source: EIA Annual Electric Power Industry Report 2018

Enhanced reliability reporting supports the State's grid modernization efforts by increasing transparency into the reporting metrics for reliability standards and by requiring the IOUs to publicly describe the remediation efforts they plan to take to address the worst performing circuits. The reporting will ultimately serve as an assessment tool to measure the progress in grid reliability and security improvements as indicated in SB 17 and Pub. Util. Code § 8360. [82]

[80] For more information on the EIA Annual Electric Power Industry Report, please see the following link. https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&cad=rja&uact=8&ved=2ahUKEwi2yuiz_IPmAhUESK0KHTnmBAMQFjAAegQIAxAB&url=https%3A%2F%2Fwww.eia.gov%2Felectricity%2Fdata%2Feia861%2F&usg=AOvVaw1Y7MAV9o3oKd9-LWjXRO22.

[81] The reliability indices excluded major event days and ISO outages.

[82] Please see the following link for the SB 17 Bill text: http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200920100SB17.

3.1.9 CUSTOMER DATA ACCESS

The Click-Through Authorization Process

In 2018, the IOUs completed the first phase of the click-through authorization process, which allows customers to easily share their energy data with third-party DR providers who can use the data to help the customer optimize their DR performance.[83] Prior to the improved click-through authorization process, customers would either have to fill out a paper authorization form or go through a multi-step online authorization process on the IOU's website. The new streamlined process on the IOU's website can now be completed in as little as two-screens and four-clicks. From 2018 to the end of 2019, all three IOUs have processed a total of 137,725 authorizations of 139,708 service accounts.[84] PG&E processed 37,970 authorizations from 38,954 service accounts in 2018 and 41,374 authorizations from 42,361 service accounts in 2019. SCE processed 17,524 authorizations from 18,842 service accounts in 2018 and 17,972 authorizations from 18,872 service accounts in 2019. SDG&E processed 9,211 authorizations from 9,248 service accounts in 2018 and 13,674 authorizations from 11,431 service accounts in 2019.

Expanding the Click-Through Authorization Process

The IOUs filed applications to expand the click-through process on November 26, 2018, per Resolution E-4868 Ordering Paragraph 29.[85,86] Resolution E-4868 ordered the IOUs to include in an application proposals to:

- Expand the click-through authorization process to DER and energy management providers, which include consideration of customer protection issues and the evaluation of which data sets should be available to which providers;
- Make improvements to the click-through authorization processes;
- Improve data delivery processes;
- Offer an alternative click-through authorization processes; and
- Deliver the expanded data set, within ninety seconds.

---

[83] PG&E, SDG&E and SCE completed their authorization processes in February 2018, March 2018, and April 2018 respectively.

[84] Information about the number of authorizations and service accounts processed by the IOUs click-through processes was taken from the IOUs compliance filings pursuant to D.15-03-042, Ordering Paragraph 1, Quarterly Reports to Track Progress of Rule 24 and Rule 32 implementation (Quarterly Rule 24/32 Reports) for March 2018, June 2018, September 2018, December 2018, March 2019, June 2019, and September 2019.

[85] Please see the following link for Resolution E-4868: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M194/K746/194746364.PDF.

[86] Applications 18-11-015, 18-11-016, and 18-11-017 are accessible through the following links: https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO:RP,57,RIR:P5_PROCEEDING_SELECT:A1811015; https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO:RP,57,RIR:P5_PROCEEDING_SELECT:A1811016; and https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO:RP,57,RIR:P5_PROCEEDING_SELECT:A1811017.

Geospatial Tools to Combat Climate Change

Since 2014, the CPUC has been part of a group of state and local agencies to support the development of the Energy Atlas, a geospatial analytical tool developed by UCLA's California Center for Sustainable Communities Institute of the Environment. The Energy Atlas 2.0, released in August 2019, uses public records combined with energy consumption data at the building level to reveal previously undetectable patterns about how people, buildings, and cities use energy. The tool helps regional planners and decision makers more effectively target energy program interventions and develop policies to mitigate and prepare for climate change. CPUC D.18-05-041 (Ordering Paragraph 32) directs the utilities to expand these capabilities to all IOU territories statewide.[87,88]

3.2. SMART GRID ACTIVITIES EXPECTED IN 2020

Below is a list of some of the Grid Modernization and Smart Grid development projects anticipated in 2020:

- **Distribution Resources Plan –** Deferral solicitation results from the 2019 DIDF cycle will be submitted summer 2020 for CPUC approval. Refinements are expected for the 2020 DIDF cycle, with the annual IOU GNA and DDOR filings currently scheduled to occur on August 15. The annual DPAG will reconvene from September through October 2020 to review the filings and the IOUs will submit candidate distribution investment deferral opportunities to the CPUC for approval in November 2020. Additionally, improvements are expected for the ICA information provided on the IOUs' DRP geospatial data portals to streamline Rule 21 interconnection processes and to facilitate DER interconnections.
- **Microgrids** – The Microgrids OIR, R.19-09-009, will continue into 2020 and focus on addressing issues identified during the 2019 Workshop. A working group will be formed to collaborate on actions to reduce barriers and to facilitate the deployment of microgrids. Activities may involve developing standards, protocols, tariffs, and guidelines for interconnection. The Microgrid OIR deliverables may include party alternative proposals on proposed approaches to implementing SB 1339 (Stern) and during Quarter 4 of 2020 for the writing of a proposed decision addressing SB 1339.

[87] Please see the following link for the text of D.18-05-041: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M215/K706/215706139.PDF.

[88] The Energy Atlas is a free, public tool that is available at http://www.energyatlas.ucla.edu/.

- **Interconnection Rule 21 –** In 2020, the CPUC will issue Decisions addressing the recommendations of Rule 21 Working Groups Two and Three, as well as those of the V2G AC Interconnection subgroup. Working Group Four will commence and address safety and environmental issues, Rule 21 updates necessary for the implementation of the California Zero Net Energy building codes, and opportunities arising from the increased operational flexibility of distributed resources. Phases 2 and 3 of the Rule 21 Interconnection proceeding—addressing small and multi-jurisdictional utility rates and rate-setting issues—will commence after those working groups finalize their recommendations.
- **Smart Inverters –** In 2020, smart inverter Phase 2 communications requirements and new advanced functions will be mandatory for all inverter-based generation interconnecting under Rule 21. Once activated, these functions could increase the amount of renewable generation that the grid can accommodate without upgrades and could contribute to grid safety and stability. The Rule 21 Interconnection OIR (R.17-07-007) will consider operational requirements of smart inverters including rules and procedures for adjusting smart inverter advanced functions via communication controls.
- **Energy Storage –** The CPUC Staff anticipates a significant ramp up of procurement activities as a result of the CPUC Decision D.19-11-016, Requiring Electric System Reliability Procurement for 2021-2023. D.19-11-016 orders 3,300 MW of incremental procurement of non-fossil resources by all LSEs. Another driver of increased storage procurement is publication of the CPUC's latest IRP Reference System Plan. The Plan calls for the procurement of approximately 11 gigawatts (GW) of energy storage resources over the next decade. CPUC Staff expects that significant work in refining the storage target and clarifying other issues related to procurement and market participation of energy storage resources of all types will be a major focus in 2020. Finally, the CPUC will contract for an evaluation framework and report on the California Storage Framework achievement of storage goals.
- **Transportation Electrification –** The CPUC is reviewing several applications, which it will continue to work on in 2020. Specifically, the CPUC is reviewing SCE's application for Charge Ready 2 and SDG&E's Power Your Drive 2, both expansions of the IOUs' existing light-duty PEV infrastructure pilots. Submetering PEVs involves measuring the PEV load separate from the rest of the house load to facilitate grid-beneficial charging. Submetering PEVs is scoped into the DRIVE OIR to be addressed in 2020. CPUC staff held a workshop on the past PEV Submetering Pilot in 2019 and directed further data gathering and reporting from the IOUs following this workshop. In

2020, the CPUC will likely direct next steps on submetering. The Clean Fuel Reward program is expected to launch in 2020. The CPUC will be supporting this process and working with the utilities to ensure sufficient data is gathered and that the dealers and customers receive adequate rate education.

- **Demand Response -** CPUC staff will hold workshops to discuss further refinements to DRAM per its D.19-07-009 proceeding. The utilities will conduct a new DRAM solicitation to procure DR from third parties for delivery in 2021. CPUC staff will also oversee an evaluation of DRAM expected to be completed by the end of 2021. Consideration of the Load Shift Working Group pilot proposals will continue in 2020 under the SDG&E GRC Application A.19-03-002. In April 2020, the IOUs will each submit a mid-cycle status report on key parameters of the five-year portfolio of demand response programs and file any requests for small program changes. The utilities will also propose an implementation plan for a new 5-in-10 residential customer baseline, which the Baseline Analysis Working Group found to be more suitable for this sector. This will apply to residential customers in the Capacity Bidding Program.
- **Customer Data Access –** In 2020, the CPUC expects that the Click-Through Authorization Process application proceeding will develop a record on improvements and expansion of the click-through process that allows customers to share their data with a third-party DER provider. Additionally, the utilities will issue a request for proposals in early 2020 for the expansion and statewide rollout of these geospatial tools, with work expected to begin in 2020.
- **General Rate Cases -** The CPUC will continue to review PG&E's 2020 Test Year GRC (A.18-12-009) and begin reviewing SCE's 2021 Test Year GRC in 2020. Both GRCs include several proposed Grid Modernization-related investments.

4. SMART GRID PROJECTS IN CALIFORNIA

4.1 SUMMARY OF IOU ACTIVITIES IN 2019

The State of California and the California IOUs continued to advance Smart Grid development initiated in 2009 pursuant to SB 17.[89] Utility activities are reported in the Smart Grid Annual Reports, which are filed by the IOUs each October, per D.10-06-047,[90] and are organized into the categories below:

- Customer Engagement and Empowerment;
- Transmission and Distribution Automation and Reliability;
- Asset Management and Operational Efficiency;
- Cyber and Physical Grid Security; and
- Integrated and Cross-Cutting Systems.[91]

Examples of utility programs and pilots related to the above activity categories can be found later in the section for each individual utility.

4.1.1 SMART GRID DEPLOYMENT BENEFITS

The IOUs are required to report the monetary value of benefits derived from Smart Grid activities. While the methodology for calculating benefits among the three IOUs has some variability, they all calculate reliability benefits as the largest benefit of Smart Grid activities. In prior years each utility estimated their own reliability benefits using a Value-of-Service reliability model developed by the Lawrence Berkeley National Laboratory (LBNL). This model is used to determine reliability benefits by monetizing reductions in customer minutes of interruption that are achieved through fault location isolation and service restoration

[89] Please see the following link for the SB 17 Bill text: http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200920100SB17.

[90] The names of the reports are as follows for SDG&E, SCE and PG&E respectively: "SDG&E Smart Grid Deployment Plan 2018 Annual Report", "Southern California Edison Smart Grid Annual Deployment Plan Update", and "Pacific Gas and Electric Company Smart Grid Annual Report – 2018." All these reports can be found on the CPUC website at: http://www.cpuc.ca.gov/General.aspx?id=4693.

[91] PG&E also reported on their Community Wildfire Safety Program for the first time in 2019 for their Smart Grid Report. SCE and SDG&E did not report on comparable wildfire-specific programs.

(FLISR) and other distribution automation technologies.[92] While the IOU's utilize the same Value of Service Reliability model as the foundation for estimating their reliability benefits, their estimated value of service measured by dollars per customer minute of interruption (CMI) differ from one another. For instance, SCE estimates a value of $2.63 for each avoided CMI which is slightly lower relative to PG&E's estimated $2.68 per avoided CMI. This difference is in part attributed to the different proportions of various customer classes like commercial, industrial, residential, and agricultural that make up the IOUs' service territories.

Furthermore, the utilities have different methodologies for estimating the number of avoided outage minutes that are obtained through smart grid technologies. As was shown on Table 1 on page 10, SCE estimated 238.9 million avoided CMI for 2019, which is nearly three times higher than PG&E's estimated 87.2 million avoided CMI, even though both utilities serve a similar number of customers in similarly sized service territories. Additionally, SCE's avoided CMI figure of 238.9 million is about 80 times higher than SDG&E's 3 million CMI, but SDG&E is comparatively a much smaller utility relative to SCE.[93] As a consequence of SCE's higher estimate for avoided CMI relative to the other IOUs, SCE's calculated reliability benefits are significantly higher than those recorded by SDG&E and PG&E. The costs and benefits shown in Table 1 on page 10 were accrued from July 1, 2018, to June 30, 2019, which is the reporting period of the 2019 IOU Annual Update reports.

According to the IOUs, smart meter deployments continued to provide value during the reporting period. The utilities also reported benefits to customers, markets, and the utility from automation projects. Environmental benefits related to the integration of renewable energy generation resources, both centralized and distributed, as well as those related to electric vehicle load were noted. Other identified benefits relate to operational, reliability, and demand response/energy conservation. Smart Grid investments continue to contribute to a safe, reliable, resilient, and sustainable grid.

[92] FLISR is a software system integrated into the utilities' outage management system that limits the impact of outages by quickly opening and closing automated switches and reconfiguring the flow of electricity through a circuit. By reconfiguring the flow of electricity, FLISR can minimize the number of customers impacted by an outage and to isolate the outage to reduce restoration times. With FLISR, outages that may have been one- to two-hours in duration can be reduced to less than five minutes.

[93] According to SCE and PG&E, this is the result of different estimation methodologies for avoided outages. SCE calculates their theoretical CMI for each circuit using modeling through a program called CYME and compares this to the actual CMI for each circuit. SCE takes the difference between the two to obtain the avoided CMI which can later be used to calculate the reliability benefit by multiplying by $2.63 per CMI. SCE assumes the benefits of their distribution automation is available on all circuits that have distribution automation technologies installed. On the other hand, PG&E obtains their estimated avoided CMI from their FLISR program based on comparing to outage data from 2013 as a baseline. PG&E's calculated difference represents their avoided CMI from their smart grid technologies installed since 2013 and similar to SCE, this figure would be multiplied by their cost per CMI ($2.68) to obtain PG&E's estimated reliability benefit.

1. Customer Empowerment

The IOUs consider the customer to be an integral part and prominent driver of the Smart Grid program. They aim to provide customers with information such as energy usage, rates, energy conservation, and peak-load reductions. Using this information, customers will be empowered to better understand and manage their energy use and costs, including their use of time-variant rates. Applications and tools are designed to meet customers' evolving communication preferences and expectations. Projects that deliver information, services, and control pursued by customers themselves and that enable demand response, dynamic pricing, and HANs are included in this category.

2. Transmission and Distribution Automation/Utility Operations

Transmission Automation and Reliability (TAR) and Distribution Automation and Reliability (DAR) projects improve the utilities' information and control capabilities on both the transmission and distribution levels of the electric grid. TAR projects provide the wide-area monitoring, protection, and control tools necessary to monitor bulk power system conditions; to safely and reliably incorporate utility-scale intermittent power generation; and to prevent emerging threats to transmission system stability. DAR projects similarly provide the ability to safely and reliably incorporate high penetrations of distributed energy resources on the distribution level, including the increasing load of electric vehicles. DAR projects also detect and isolate faults, provide "self-healing"[94] benefits, and to provide optimization of voltage and reactive power to enhance power quality and to decrease energy consumption. TAR and DAR help deliver a Smart Grid that has the infrastructure necessary to support the integration of demand response, energy efficiency, distributed generation, and energy storage.

3. Asset Management, Safety, and Operational Efficiency

This category enhances monitoring, operating, and optimization capabilities to achieve more efficient grid operations and to improve asset management. These projects enable the utilities to manage the maintenance and replacement of the grid's infrastructure on a health-basis rather than on a time-in-service basis, which should minimize critical equipment failure. This functionality also helps the IOUs manage costs associated with maintaining and replacing equipment.

4. Cyber and Physical Grid Security

Physical and cybersecurity investments are becoming more important as the communications and control systems needed to enable Smart Grid capabilities increase in size and reach. These systems have the

[94] Self-healing benefits refer system reliability benefits derived from a network of sensors, automated controls, and advanced software that utilize real-time distribution data to detect and isolate faults and to reconfigure the distribution network to minimize the customers impacted.

potential to increase the reliability risks of the electric grid if the systems are not properly secured. The security programs of the IOUs enhance security throughout the network to resist attacks, and to manage compliance and risks. Security is paramount to the full development, implementation, operation, and management of the Smart Grid.

5. Integrated and Cross-Cutting Systems

Integrated and cross-cutting systems refer to activities that support multiple areas of utility operations and may involve such systems as grid communications, data management and analytics, and advanced technology testing. An integrated approach helps to ensure that the overall network is efficient and delivers benefits across IOU operations and to customers. Integrated communications systems will provide solutions to enable sensors, metering, maintenance, and grid asset control networks. Over the long term, these systems will enable information exchange among IOUs, service partners, and customers by way of secure networks. Advanced technology testing and standards certification are fundamental for the utilities to accommodate new devices from vendors. Workforce development and advanced technology training will also be required to enable the successful deployment of new technologies and to ensure that the IOUs are prepared to make use of emerging technologies and tools, which will maximize the value of these technology investments.

4.1.2 ADVANCED METERING INFRASTRUCTURE DEPLOYMENT

Table 4. Advanced Metering Infrastructure (aka Smart Meters) Rollout[95] as of Oct. 2019[96]

IOU	Total Number of Electric Smart Meters (Millions)	Cumulative Electric Smart Meter Opt-outs[97] (No. of customers)	Percentage of Opt-outs	Annual Customer Complaints (escalated) [98]
PG&E	5.44	43,064	0.79%	9
SDG&E	1.45	4,217	0.29%	0
SCE	4.7	22,972	0.48%	495
Total	11.59	70,253	0.61%	504

Source: IOU 2019 Smart Grid Reports and Data Requests

[95] These statistics only include data as reported by the State's electric Utilities in the Smart Grid Annual Reports. The State's gas Utilities have also deployed millions of Smart Meters.
[96] The reporting period was from November 1, 2017 to October 31, 2018.
[97] Opt-out totals listed here are since the beginning of the Smart Meter programs.
[98] Escalated complaints are customer complaints regarding smart meters that have gone through the complaint process and reached resolution during the reporting period.

In 2007, with Commission approval, the IOUs began full deployment of Advanced Meter Infrastructure, which was largely completed in 2013. Electric Smart Meter opt-outs refer to customers who have either declined to adopt smart meters or returned to using analog meters. The percentage of opt-outs relative to the total number of customer accounts with Smart Meters has remained less than one percent for all the IOUs. Annual escalated customer complaints have increased over the past year by 50, or by 5.5 percent.

4.1.3 UTILITY PUBLIC SAFETY POWER SHUT-OFF

The State's Investor Owned Utilities, PG&E, SCE, and SDG&E have general authority to shut off electric power to protect public safety under California law, see California Public Utilities Code Sections 451 and 399.2(a). This process is called de-energization or Public Safety Power Shut-off (PSPS). This authority includes shutting off power if the utility reasonably believes that there is an "imminent and significant risk" that strong winds may topple power lines or cause major vegetation-related damage to power lines, leading to increased risk of fire.

The State's utilities will de-energize electric facilities only during periods of extreme fire hazard and only after weighing several criteria including fuel conditions, weather forecasts, and on-the-ground real-time observations. As potentially hazardous conditions develop, the utilities will inform the CPUC, California Governor's Office of Emergency Service (CalOES), the California Department of Forestry and Fire Protection (CAL FIRE) and local public safety authorities of the potential for a PSPS event. Following these notices, the utilities will conduct outreach via multiple channels to potentially impacted customers informing them of the potential for a power shutdown. If the hazardous conditions continue to develop the utilities will proceed with de-energizing electric facilities within the impacted area. Following the weather event utility crews will inspect all de-energized lines and restore power to impacted communities.

On July 12, 2018, the CPUC adopted Resolution ESRB-8 which contains rules to strengthen customer notification requirements before de-energization events and orders utilities to engage local communities in developing de-energization programs.[99] Resolution ESRB-8 also requires utilities to submit post-event reports to the Director of the CPUC's Safety and Enforcement Division (SED) within 10 business days of a PSPS event. D.19-05-042 adopted PSPS communication and notification that expanded the Resolution ESRB-8 guidelines, which remain in effect.[100]

[99] For the full text of Resolution ESRB-8, please see the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M217/K801/217801749.PDF.

[100] For the full text of D.19-05-042, please see the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M296/K598/296598822.PDF.

In October 2019, PG&E initiated back-to-back PSPS events from October 9-12 and October 26 - November 1 that impacted 728,980 and 941,000 unique customer accounts respectively; millions of people were without electricity for multiple days.[101] Also during the October 9-12 event, PG&E experienced significant issues with its communications and its website crashed, so customers were unable to access critical information about the event. In response to these issues, the Commission held an emergency Commission meeting on October 18, 2019, and imposed additional requirements on PG&E. Additionally, the CPUC issued an Order to Show Cause (OSC) to PG&E in the open PSPS Proceeding, R.18-12-005, to determine whether PG&E should be sanctioned by the Commission for violation of Public Utilities Code Section 451, D.19-05-042, and Resolution ESRB-8.[102] Furthermore, the CPUC opened Investigation (I.) 19-11-013 to determine whether the IOUs prioritized safety and complied with the Commission's regulations and requirements with respect to their PSPS events in late 2019.[103] The OSC and Investigation will take place over the course of 2020 and will be conducted in parallel with the CPUC's assessment of new and updated PSPS guidelines that the CPUC seeks to implement in advance of the 2020 fire season.

In addition to the procedural steps described above, the CPUC continues to work with CalOES, CAL FIRE, and first responders throughout the state to address potential impacts of utility de-energization practices on emergency response activities, including evacuations. Additionally, the CPUC continues to assess the implementation of PSPS programs by utilities, including performing a thorough review of de-energization events as they occur and after they conclude by evaluating the post-event reports.

[101] The average outage duration for these events was 37 hours and 55 hours for the October 9-12 and October 26 - November 1 events respectively.

[102] For the full text of the PG&E OSC in R.18-12-005, please see the following link: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M319/K530/319530378.PDF.

[103] For the full text of I.19-11-013, please see the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M319/K821/319821875.PDF.

4.2 HIGHLIGHTS OF SAN DIEGO GAS & ELECTRIC'S (SDG&E) SMART GRID DEPLOYMENT

This section provides information on SDG&E's estimated expenditures and benefits realized during the reporting period, and it highlights some of SDG&E's projects.

4.2.1 SDG&E Example Projects

Costs

Table 5. SDG&E's Estimated Smart Grid Costs for Fiscal Year July 1, 2018 through June 30, 2019

Task	Value
Customer Empowerment and Engagement	$500,000
Distribution Automation and Reliability	$32,388,000
Transmission Automation and Reliability	$4,390,000
Asset Management, Safety and Operational Efficiency	$3,390,000
Security	$25,546,000
Integrated and Cross-Cutting Systems	$1,057,000
Total Estimated Costs	$133,541,000

Benefits

Table 6. SDG&E's Estimated Smart Grid Benefits Realized for Fiscal Year July 1, 2018 through June 30, 2019

Benefit	Value
Reliability Benefits	$34,846,000
Physical and Cybersecurity Benefits	$11,714,000
Customer Demand Response Benefits	$610,000
Avoided Costs (Operational, Capital, Environmental)	$52,733,000
Total Estimated Benefits	$99,903,000
Avoided Outage Minutes	3 Million

The following are highlights of SDG&E's Smart Grid deployment:

- SDG&E experienced a 22.5 percent growth rate in NEM distributed generation (DG) with residential and commercial customers connecting nearly 30,000 new systems (primarily solar), bringing the total number of interconnected DG systems to 163,938 and NEM generation capacity to nearly 1,130 MW;
- Customers continue to deploy energy storage in the commercial/industrial sector and have now connected over 57 MW to SDG&E's grid; and
- Plug-in electric vehicle penetration grew to nearly 42,000 vehicles (both plug-in electric and plug-in hybrid), which represents an increase of 11,000 vehicles from the previous year.[104]

4.2.2 SDG&E EXAMPLE PROJECTS

- **Distributed Energy Resource Management System (DERMS)** – The DERMS project was initiated in order to develop a software solution to monitor, control, and optimize DERs by:
    1. Integrating and aggregating batteries, solar, generators, and other DERs for improving reliability and market participation;
    2. Using load forecasting, day-ahead price signals, the demand response management system (DRMS), and other factors to give multiple options for optimization and scenario-based operations; and
    3. Providing the ability for future integration with DMS, GIS, DRMS, and numerous other functions.

  The project has successfully deployed the microgrid at the Borrego Microgrid and has completed deployments of the Advanced Energy Storage controller software application for the Miguel Vanadium Redox Flow (VRF) Battery System and for the Del Lago Park n' Ride Energy Storage System.

- **Borrego Springs Microgrid** – This project seeks to establish a microgrid demonstration at an existing substation to evaluate the effectiveness of integrating multiple DER technologies, feeder automation system technologies, and outage management system (OMS) to improve reliability during outages. The Borrego Springs Microgrid can island all three circuits out of Borrego Springs, which has a peak load of 14 MW and serves about 2,500 residential and 300 commercial and

[104] SDG&E notes that 600 of their employees also drive electric vehicles and there are over 280 EV workplace charges at SDG&E facilities.

industrial customers. SDG&E completed the final project report, and in the first quarter of 2019, the CEC published the report, "Borrego Springs: California's First Renewable Energy Based Community Microgrid."[105]

- **Supervisory Control and Data Acquisition (SCADA) Expansion –** SCADA is a system of software and hardware elements that allow distribution system operators to remotely gather, monitor, and process data from sensors deployed along the distribution system. For this project, SDG&E plans to install 300 SCADA line switches in order to have an average of 1.5 switches on every distribution circuit. Additionally, SDG&E will install SCADA at 13 existing substations. Through this project, SDG&E aims to have circuit automation at these locations in order to provide faster isolation of faulted electric distribution circuits that in turn will result in faster load restoration when system disturbances occur. In 2019, SDG&E installed SCADA at the Descanso, Pendleton, and Warners substations. Engineering plans are addressing the addition of SCADA to the Rancho Santa Fe and Poway substations in 2020. The Capistrano substation will be rebuilt with SCADA as part of the Southern Orange County Reliability Enhancement project.
- **Power Your Drive (PYD)** –This pilot project is designed to deploy EV charging stations in both multifamily dwellings and workplaces combined with a dynamic hourly EV rate to encourage customer EV adoption and charging during hours that are optimal for the grid. As part of the project, SDG&E plans to install and operate 5,015 electric vehicle charging ports at 454 sites.[106] SDG&E has goals of locating at least 10 percent of the overall installations in disadvantage communities (DACs) and 40 percent of the multifamily installations in DACs. Customers participating in the program are assessed a nominal one-time payment. However, if the site is within a DAC, then the payment is waived. To date, 254 customers have executed Site Agreements with SDG&E, and a total of 3,015 ports have been completed. Of the 254 sites, 35 percent are within DACs.

[105] For the full text of the CEC's report on the Borrego Springs microgrid, please visit: https://www.energy.ca.gov/2019publications/CEC-500-2019-013/CEC-500-2019-013.pdf.

[106] In October 2019, SDG&E submitted Application (A.) 19-10-012 in which SDG&E seeks to expand the Power Your Drive program by adding an additional 2,000 ports at 200 sites to the 3,015 ports at 254 sites that were completed in 2019 at the conclusion of the original pilot phase. The original pilot targeted 3,500 ports at 350 sites. A.19-10-012 is available through the following link: https://www.sdge.com/sites/default/files/regulatory/A.19-10- %20SDG%26E%20PYD%202%20-%20Application%20w_Attachments%20FINAL%20MASTER.pdf.

4.3 HIGHLIGHTS OF SOUTHERN CALIFORNIA EDISON (SCE) SMART GRID DEPLOYMENT

This section provides information on SCE's estimated expenditures and benefits realized during the reporting period, and it highlights some of SCE's projects.

4.3.1 SCE SMART GRID COSTS AND BENEFITS

Costs

Table 7. SCE's Estimated Smart Grid Costs Realized for Fiscal Year July 1, 2018 through June 30, 2019

Task	Value
Customer Empowerment and Engagement	$19,030,965
Distribution Automation and Reliability	$42,242,038
Transmission Automation and Reliability	$43,781,739
Asset Management, Safety and Operational Efficiency	$753,607
Security	$0[107]
Integrated and Cross-Cutting Systems	$9,576,614
Total Estimated Costs	$115,384,963

[107] The Common Cybersecurity Services (CCS) platform project was completed and deployed during the 2016 update reporting period.

Benefits

Table 8. SCE's Estimated Smart Grid Benefits for Fiscal Year July 1, 2018 through June 30, 2019

Benefits	Value
Reliability Benefits[108]	$628,300,000
Physical and Cybersecurity Benefits	N/A[109]
Customer Demand Response Benefits[110]	$2,900,000
Avoided Costs (Operational, Capital, Environmental)	$28,200,000
Total Estimated Benefits	$709,100,000
Avoided Outage Minutes	239 Million

The following are highlights of SCE's Smart Grid deployment:

- SCE received approval of a $378 million budget to build out its transportation electrification infrastructure and has deployed a cumulative total of 1,321 charge ports at 80 customer sites. 658 of the ports, or 50 percent, that are located in disadvantaged communities;
- SCE's plan to migrate residential customers to default TOU rate structures, beginning in October 2020, was approved in CPUC D.19-07-004;[111]
- As of 2019, the number of distribution circuits equipped with automation or remote-control equipment, including SCADA systems, has reached 3,699, and represents approximately 90 percent of the total 4,163 distribution circuits;
- In 2019, SCE installed 177 remote control switches and 204 remote sectionalizing reclosers in order to enhance circuit automation and to improve the overall performance and reliability of the distribution system;

108 In past reports, this benefit was calculated based on Lawrence Berkeley National Laboratory's Value-of-Service (VOS) reliability model. In support of SCE's 2018 GRC filing, SCE has changed how reliability improvements are calculated that are achieved through distribution automation and how those improvements are valued through updating its VOS estimates. The other utilities have not similarly updated their VOS estimates. The modified approach indicates a significant increase in calculated reliability benefits relative to past reports. (Smart Grid Annual Deployment Plan Update, p.8). As a disclaimer, this data point is shown as it was reported by SCE to the CPUC. This method has not been vetted by the Commission and the CPUC cannot attest to its accuracy.

109 SCE's pilot projects did not specifically track physical and cybersecurity costs and benefits.

110 According to SCE, "Demand Response and Energy Conservation benefits are specifically attributed to demand response enabled by Auto-DR technology and controllable programmable communicating thermostats for SCE's PTR-ET-DLC program." (SCE 2019 Smart Grid Deployment Plan, p.8)

111 D.19-07-004 is available through the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M309/K843/309843509.PDF.

- SCE's implementation of distribution Volt/VAR control, which is intended to coordinate and optimize voltage and VARs across all circuits fed by a substation, has been successfully completed at 300 substations across SCE's service territory. SCE estimates the avoided energy procurement and capacity costs related to deploying distribution Volt/VAR control should provide a 1 percent actual savings in energy costs for customers per 1 percent reduction in voltage.

4.3.2 SCE EXAMPLE PROJECTS

- **PHASOR** – According to the U.S. Department of Energy, synchrophasors are "sophisticated monitoring device[s] that can measure the instantaneous voltage, current, and frequency at specific locations on the grid." [112] Synchrophasors enable SCE to collect, verify, and share Phasor Measurement Unit (PMU) information about the status and health of the grid at millisecond intervals. This allows SCE to obtain an almost real-time picture of what is happening on their system and allows SCE to take actions to prevent power outages. Furthermore, the technology can be leveraged to prevent wildfires by detecting and turning off broken lines before they hit the ground and possibly spark a fire. SCE, SDG&E, and PG&E are working in collaboration with the Western Electricity Coordination Council on their Phasor program. The Phasor system will also allow SCE to meet its compliance obligations as part of SCE's participation in the Western Interconnect Synchrophasor Program. SCE completed testing and implementation in 2013 and continues to send Synchrophasor data to and from Peak Reliability, a reliability coordinator listed with NERC in the Western Interconnect.[113]
- **Circuit Automation** –SCE began this program in 2010 in order to automatically or remotely restore power to customers after outages caused by faults and to minimize the impact on customers of outages that occur in the ordinary course of business. During the 2019 reporting period, SCE installed 177 remote control switches, 204 remote sectionalizing reclosers, and spent approximately $27 million.

- **Distribution System Efficiency Enhancement Project** – SCE's Distribution System Efficiency Enhancement Program (DSEEP) is intended to service and expand SCE's wireless communication system known as NETCOMM. SCE's NETCOMM system allows SCE to utilize their radio communication infrastructure to remotely monitor and control SCE's distribution automation

[112] https://www.energy.gov/articles/how-synchrophasors-are-bringing-grid-21st-century.
[113] For more information about Peak Reliability, please see the following link to their website: https://www.peakrc.com/Pages/default.aspx.

devices.[114] In 2019, SCE added 4,607 distribution automation devices and 44 infrastructure radios, extending communication to the new devices. SCE also conducted maintenance on existing infrastructure which consisted of replacing 678 automation devices and 278 packet radios to maintain network performance levels. Additionally, SCE replaced 500 end-of-life battery-backed radios.

- **Charge Ready Program** –The purpose of the Charge Ready Program is to deploy EV charging stations at locations where EVs will be parked for four or more hours, such as multi-family dwellings, workplaces, fleet parking, and destination centers. SCE also conducts market education to develop awareness of EVs and their benefits to the grid and to customers. Charge Ready customers are required to participate in demand response as part of the related Charge Ready DR Pilot. The DR pilot held 14 test events through 2019 for evaluating the vehicles' abilities to reduce load during peak times and to shift load during times of high renewable generation. SCE intends to conduct additional test events and analysis into 2020. In December 2018, the CPUC approved an additional $22 million to continue implementing the Charge Ready Pilot. By the end of the reporting period, SCE had 80 sites and 1,321 charge ports committed for overall deployment. 658 or 50 percent of these charge ports are located in disadvantaged communities.

[114] These devices include all the devices SCE deployed in their related Circuit Automation program (remote control switches and remote sectionalizing recloser), Capacitor Automation program (programmable capacitor controls) and remote fault indicators.

4.4 HIGHLIGHTS OF PACIFIC GAS & ELECTRIC (PG&E) SMART GRID DEPLOYMENT

This section provides information on PG&E's estimated expenditures and benefits realized during the reporting period, and it highlights some of PG&E's projects.

4.4.1 PG&E SMART GRID COSTS AND BENEFITS

Costs

Table 9. PG&E's Estimated Smart Grid Costs for Fiscal Year July 1, 2018 through June 30, 2019

Task	Value
Community Wildfire Safety Program[115]	$19,440,000
Customer Empowerment and Engagement	$68,220,000
Distribution Automation and Reliability	$54,970,000
Transmission Automation and Reliability	$68,900,000
Asset Management, Safety and Operational Efficiency	$21,190,000
Security	$7,770,000
Integrated and Cross-Cutting Systems	$13,240,000
Total Estimated Costs	$253,730,000

Benefits

Table 10. PG&E's Estimated Smart Grid Benefits – Fiscal Year July 1, 2018 through June 30, 2019

Benefits	Value
Customer Reliability Benefit[116]	$194,000,000
Customer Demand Response Savings	$372,000
Avoided Costs (Operational, Capital, Environmental[117])	$5,900,000
Total Estimated Benefits	$200,272,000
Avoided Outage Minutes[118]	87.2 million

115 The Community Wildfire Safety Program is only a PG&E program.

116 PG&E's customer reliability benefits are derived from calculating the monetary benefits from avoided customer outage minutes that were achieved through its FLISR program.

117 For details on PG&E's Environmental developments, please see PG&E's Corporate Sustainability Report at: http://www.pgecorp.com/corp/responsibility-sustainability/corporate-responsibility-sustainability.page.

118 The avoided outage minutes are calculated based on customer interruption minutes that were saved as a result of FLISR technologies.

The following are highlights of PG&E's Smart Grid deployment:

- The subset of customers who enrolled in the Bill Forecast Alert and High Usage Alert programs saved an estimated $372,000 this past year with 9,521 MWh of energy savings;
- PG&E began implementing enhanced local situational awareness projects to avoid the risk of catastrophic wildfires through activities such as setting up its Wildfire Safety Operations Center, improving its weather forecasting abilities, and using satellite-based early warning fire detection;
- PG&E installed substation equipment at the Idaho National Laboratory's test facility for threat assessment exercises to gain high-resolution assessments of potential effects of various physical and cyber tactics that can be employed against the grid and to test mitigations;
- Smart Meter outage information improvement reduced an estimated 8,400 "truck rolls"[119] and saved PG&E over $700,000 over the reporting period;
- Over 420,000 NEM customers have installed rooftop solar and 235,000 customers have replaced internal combustion vehicles with electric vehicles in PG&E's service territory.

4.4.2 PG&E EXAMPLE PROJECTS:

- **Distribution Supervisory Control and Data Acquisition (SCADA) Program** – This program is focused on increasing SCADA penetration in the distribution system and improving reliability for PG&E's customers. PG&E's goal is to achieve 100 percent visibility and control over all critical distribution substation breakers over the next few years by adding or replacing SCADA for approximately 530 substations and 2,030 breakers. By the end of the 2018 reporting period, the project had upgraded SCADA in 432 substations and 1,670 breakers. Between 2011 and 2019, the project has upgraded or replaced SCADA in 495 substations and 1,930 breakers. PG&E estimates that it will achieve 99 percent penetration by December 2020. Additionally, at the conclusion of Q2 2019, PG&E completed SCADA-enabling on approximately 87 percent of line recloser devices on lines serving or running through Tier 2 and Tier 3 High Fire Threat District (HFTD) areas. This will allow PG&E to remotely disable line recloser devices during high fire danger conditions so that the reclosers do not automatically reclose and re-energize a line after opening when a fault is detected and potentially spark a fire. On a related note, over 98 percent of reclosing devices on approximately

[119] Truck roll refers to a utility dispatch of technicians to investigate electrical equipment during an outage.

400 transmission lines with voltages of 115 kV or below are now SCADA-enabled and can also be remotely disabled.

- **Modular Protection Automation and Control (MPAC) Installation Program –** The purpose of this program is to deploy pre-engineered, fabricated, and standardized control buildings in transmission substations as part of PG&E's effort to modernize its facilities. By installing prefabricated control buildings, PG&E can save money on construction costs and ensure standardization of building units across its facilities. These MPAC upgrades are performed in conjunction with other PG&E transmission substation upgrade projects such as business conversions, control center consolidation efforts, and aging asset replacement. The program is ongoing and does not have a defined end date. As of 2019, PG&E had installed and completed 120 MPAC buildings and avoided $5.2 million in capital costs over traditional upgrade methods in 2019. PG&E has avoided $69.8 million in capital costs cumulatively since the program began in 2005.

- **Resilience Zones –** This program is in the pilot phase and is intended to reduce the public impact and to increase community resiliency during PSPS events by enabling power to stay on in designated resiliency zones. Customers served by circuits in the central business district in the resilience zone can continue to maintain normal business operations rather than suffer from a prolonged outage. While the scale and scope of each resiliency zone may vary, the following equipment will be available for use at each site:
    1. Isolation devices, which will temporarily disconnect a circuit from the grid so it can operate independently from the grid
    2. A pre-installed interconnection hub, that will allow PG&E to rapidly connect temporary generation and to energize the isolated circuit (thereby forming an energized "island")

  In order to establish a resilience zone in a given area, PG&E may need to engage in additional system hardening, such as targeted undergrounding, to ensure safe operation during weather events that could trigger PSPS events. PG&E's first resilience zone site became operational in 2019 in Angwin, California and an additional four resilience zones are currently in the design phase.
- **Electric Vehicle Infrastructure** –This program, launched in January 2018, is a three-year pilot designed to enable the deployment of make-ready infrastructure[120] to support up to 7,500 EV level-2

[120] Make-ready refers to the utility making the infrastructure ready for third parties to build out the charging stations themselves. This entails the trenching, installation of conduit and electrical wire, pulling of wires, installing concrete installation bases (if needed), potential upgrades of existing electrical infrastructure including panel additions and transformer replacement, landscape removal, paving, and guard post installation.

charging ports located primarily in workplaces and multi-family housing units. In 2019, the program was fully subscribed. PG&E received 819 program applications totaling more than 14,000 charging ports by the end of the reporting period. At the close of Q2 2019, 201 customer sites representing 4,464 charging ports had signed agreements with PG&E and the ports had been activated or were in the final design and construction phases. According to PG&E, the program will scale to completion in 2020

5. CONCLUSION

The Smart Grid policies pursued by the State of California and implemented by the State's Utilities continue to generate benefits for California ratepayers. Based on the utilities' estimates in their 2019 Smart Grid reports, the utilities' programs and projects have realized nearly $1 billion in benefits in the 2018-2019 Fiscal Year. However, California still has more to do to realize the vision of a smart and modern grid that is prepared to meet California's ambitious energy and climate goals, while also addressing the challenges posed by the increasing threat of cyber security attacks, and risk of wildfires and other extreme weather events. This will require the coordination of the CPUC, the Legislature, partner agencies such as the CEC, and the electric IOUs to invest further in grid automation, grid hardening, cybersecurity, and smart inverters and increase the penetration of distributed energy resources such as electric vehicles, demand response, and energy storage. By fulfilling the vision of the DER Action Plan, the CPUC will help move California towards a sustainable, affordable, efficient, reliable, and resilient grid. With its rich tradition of entrepreneurship, technological innovation, and forward-looking regulation, California will continue to lead the nation in Smart Grid development and deployment.

APPENDIX A – GLOSSARY OF TERMS

Advanced Distribution Management System: (ADMS) See Distribution Management System.

Advanced Metering Infrastructure: (AMI) refers to the full energy consumption data measurement and collection system that includes Smart Meters at the customer site, communication networks between the customer and utility, and data reception and management systems that make the information available to the utility.

Behind-the-Meter: (BTM) refers to electrical equipment and technologies that are interconnected on the customer's side of the electric meter. Customer-sited distributed energy resources (DERs) are one of the most common examples of BTM resources.

CAISO: California Independent System Operator maintains reliability on one of the largest and most modern power grids in the world, and operates a transparent, accessible wholesale energy market.

Circuit: A network of wires that carries power from substations or distributed generation to local load areas such as commercial and residential areas.

Click-Through Authorization Process: An online customer authorization process that allows customers to easily share their energy data with third-party demand response providers who can use the data to help the customer optimize their demand response performance.

Customer Minutes of Interruption: (CMI or CMIN) refers to the duration of an outage event measured in minutes summed across all customers affected by the event.

De-Energization: See Public Safety Power Shut-off.

Demand Response: (DR) refers to changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.

Demand Response Auction Mechanism: (DRAM) a competitive solicitation mechanism run by the investor-owned utilities that enables distributed energy resource aggregators to offer their services to utilities and the state's wholesale energy markets. The commodity being traded is measured in kilowatt-months of capacity or the ability to reduce use or add energy for up to 4 hours at a time during the state's late afternoon and evening peaks, over the course of a month.

Distributed Energy Resources: (DERs) include distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies. DERs are connected to the distribution grid both behind the customer's meter (BTM) and in front of the customer's meter (IFM).

Distribution Feeder: (Or feeder) refers to a circuit that carries power from a distribution substation to local load areas such as commercial and residential areas.

Distribution Investment Deferral Framework: (DIDF) a framework designed to identify opportunities where future distribution system upgrades can be deferred or avoided through distributed energy resource deployment as "non-wires alternatives" (NWA).

Distribution Management System: (DMS, also referred to as Advanced Distribution Management System (ADMS)) a software platform that can monitor and control the distribution system efficiently and reliably.

Distribution Planning Advisory Group: (DPAG) a body formed by market participants and an independent professional engineer who advise the utilities on the selection of distribution deferral opportunities and provide input on the development of competitive solicitation for distributed energy resources.

Distribution Resources Plan: (DRP) refers to the plans that each of the investor-owned utilities were required to develop to propose contracts, tariffs or other distribution energy resources procurement mechanisms to maximize the locational benefits and minimize the incremental costs of distributed resources. The DRPs also identify additional spending necessary to integrate distribution energy resources into distribution planning and to modernize their electric grids; as well as identify the barriers to the deployment of distribution energy resources. DRP also refers to the namesake proceeding in which the DRPs were developed.

Electric Tariff Rule 21: (Or Rule 21) refers to the tariff governing the utilities' interconnections of distributed energy resources.

Energy Atlas: A geospatial analytical tool developed by UCLA's California Center for Sustainable Communities Institute of the Environment. The Energy Atlas is the largest set of disaggregated energy data in the nation, and it uses energy consumption data at the building level, combined with public records, to reveal previously undetectable patterns about how people, buildings and cities use energy.

The tool helps regional planners and decision makers more effectively target energy program interventions and develop policies to mitigate and prepare for climate change.

EV: Electric vehicle. See plug-in electric vehicle.

Fast Track Process: A streamlined review process within Rule 21 that is based on multiple evaluation screens for interconnecting net energy metering, non-export, and small exporting facilities.

Fault Location Isolation and Service Restoration: (FLISR) a software system integrated into the utilities' outage management system that limits the impact of outages by quickly opening and closing automated switches and reconfiguring the flow of electricity through a circuit. By reconfiguring the flow of electricity, FLISR can minimize the number of customers impacted by an outage and isolate the outage to reduce restoration times. With FLISR, outages that may have been a one- to two-hours in duration can be reduced to less than five minutes.

General Rate Case: (GRC) General rate cases are proceedings used to address the costs of operating and maintaining the utility system and the allocation of those costs among customer classes. For California's three large investor-owned utilities (IOUs or Utilities), the GRCs are parsed into two phases. Phase I of a GRC determines the total amount the utility is authorized to collect, while Phase II determines the share of the cost each customer class is responsible for and the rate schedules for each class. Each large electric utility files a GRC application every three years.

Gigawatt: (GW) a unit of electric power equal to one billion watts.

High Fire Threat District: Refers to the high fire threat areas in the CPUC's Fire-Threat Map which was adopted by the CPUC in Decision (D.)17-12-024. The map consists of three fire-threat areas (Zone 1, Tier 2 and Tier 3) that have increasing levels of risk of wildfires associated with overhead utility power lines and facilities that also support communication facilities.

Home Area Network: (HAN) a communication network that is deployed and operated in a small area such as a house or small office that enables the communication of various devices such as distributed energy resources, heating and air-conditioning units, and smart household appliances for purposes of energy management and responding to variable energy price signals. Utilities can leverage HANs to manage customer load during peak hours and reduce greenhouse gas emissions from expensive gas-fired power plants that would otherwise be needed to meet peak demand.

Integrated Capacity Analysis: (ICA) quantifies the available hosting capacity of every distribution circuit in the utilities' service territories to integrate distributed energy resources without triggering grid upgrades.

Integrated Distributed Energy Resources: (IDER) refers to the CPUC's strategy for the utilities to integrate customer demand-side programs, such as energy efficiency, self-generation, advanced metering, and demand response, in a coherent and efficient manner. Also refers to the IDER proceeding which is focused on developing sourcing mechanisms for the procurement DERs that advance distribution planning objectives.

Integrated Resource Plan: (IRP) comprehensive utility procurement plans that detail what resources are to be procured and how it will be done to comply with the State's climate and energy policies and adequately balance safety, reliability, and cost while meeting the State's environmental goals laid out by SB 350 and SB 100.

Inverter: An electronic device that converts DC power to AC power and is necessary to connect most distributed energy resources to the grid. See Smart Inverter.

IOU: Investor-owned utility.

Island Mode: Refers to when a circuit or microgrid operates in isolation from the distribution grid and can continue to serve power through DERs when the distribution grid experiences outages and can no longer serve the circuit or microgrid.

Kilowatt: (kW) A unit of electric power equal to one thousand watts.

Load: The total amount of power needed to meet all demand on the grid at any given time.

Locational Net Benefits Analysis: (LNBA) a tool that can determine optimal locations for DER deployment based on cost-effective opportunities for DERs to defer or avoid traditional distribution system investments.

Megawatt: (MW) a unit of electric power equal to one million watts.

Multiple-Use Applications: (MUA) refers to the multiple benefits and services that energy storage devices can provide to the grid to increase the economic value provided.

Net Energy Metering: (NEM) Customers who install small solar, wind, biogas, and fuel cell generation facilities to serve all or a portion of onsite electricity needs are eligible for the state's net metering program. NEM allows customers who generate their own energy ("customer-generators") to serve their energy needs directly onsite and to receive a financial credit on their electric bills for any surplus energy fed back to their utility.

Order Instituting Rulemaking: (OIR) An investigatory proceeding opened by the PUC to consider the creation or revision of rules or guidelines in a matter affecting more than one utility or a broad sector of the industry. Comments and proposals are submitted in written form. Oral arguments or presentations are sometimes allowed.

On-Peak: Refers to the hours of the day in which demand for electricity tends to be the highest.

Off-Peak: Refers to the hours of the day that are not characterized by on-peak electricity demand.

Outage Management System: (OMS) a computer system used by electric distribution system operators to assist in restoration of power.

PEV: Plug-in electric vehicle. A type of zero emission vehicle (ZEV) which has no tail pipe emissions. A plug-in electric vehicle is any motor vehicle that can be recharged from an external source of electricity, such as wall sockets, and the electricity stored in the rechargeable battery packs drives or contributes to driving the wheels.

Plug-and-Play: Refers to a distribution grid system where high penetrations of distributed energy resources can be integrated seamlessly due to streamlined and simplified processes for interconnecting these technologies.

Public Safety Power Shut-off: (PSPS): Is a wildfire mitigation measure where a utility pre-emptively turns off electricity to geographic areas when gusty winds, dry conditions, and heightened fire risks are forecasted. Also referred to as de-energization.

Reactive Power Priority: A mandatory smart inverter setting for California's investor-owned utilities that allows distributed generation to provide local voltage support and mitigate voltage rise on the distribution system.

Reliability: The ability of the electric grid to deliver electricity in the quantity and with the quantity demanded by customers while minimizing service interruptions. Reliability is measured by the number of outages and outage duration.

Request for Offer: (RFO) an open and competitive solicitation process whereby an organization requests the submission of offers in response to a scope of services that is needed.

Resiliency: The ability of the grid to resist failure, reduce the magnitude and/or duration of disruptive events to the grid, and recover from disruptive events.

Resource Adequacy: a regulatory requirement designed to provide sufficient resources to the California Independent System Operator to ensure the safe and reliable operation of the grid in real time. RA is a planning reserve margin of available generation resources.

Self-Healing Benefits: Refers to system reliability benefits derived from a network of sensors, automated controls, and advanced software that utilize real-time distribution data to detect and isolate faults and to reconfigure the distribution network to minimize the customers impacted by outages and other disruptive events.

SIWG: Smart Inverter Working Group is an ad-hoc collaborative stakeholder committee that provides input and recommendations to the CPUC Rule 21 proceeding in the areas of smart inverters.

Supervisory Control and Data Acquisition: (SCADA) is a system of software and hardware elements that allow distribution system operators to remotely gather, monitor, and process data from sensors deployed along the distribution system.

Smart Inverter: A smart inverter is an inverter that performs functions that, when activated, can autonomously contribute to grid support during excursions from normal operation voltage and frequency system conditions. Smart inverters provide autonomous responses to voltage and frequency conditions, safety features, and communications capabilities. See Inverter.

Smart Meter: An electronic meter that records consumption of electric energy in intervals of an hour or less and communicates that information at least daily back to the utility for monitoring and billing. A smart meter enables customers to view their consumption hourly to enable improved energy management and responsiveness to time variant energy price signals. See Advanced Metering Infrastructure.

SONGS: Refers to the former San Onofre Nuclear Generating Station.

Time of Use Rates: (TOU) Time-of-use is a rate plan in which rates vary according to the time of day, season, and day type (weekday or weekend/holiday). Higher rates are charged during the peak demand hours and lower rates during off-peak (low) demand hours. Rates are also typically higher in summer months than in winter months. This rate structure provides price signals to energy users to shift energy use from peak hours to off-peak hours. Time of use pricing encourages the most efficient use of the system and can reduce the overall costs for both the utility and customers.

Truck Roll: A utility dispatch of technicians to investigate electrical equipment during an outage.

Vehicle-Grid Integration: (Also referred to as Vehicle-to-Grid Integration or VGI) a framework for utilizing the flexible charging and discharging capabilities of plug-in electric vehicles to serve as a grid asset.

Volt Amperes Reactive: (VAR) a measure of reactive power, which exists in an AC circuit when the current and voltage are not in phase. Certain types of loads absorb or produce reactive power, so its presence on the distribution grid is unavoidable. However, reactive power imbalances cause abnormal voltages, so VARs must be managed to keep line voltages within acceptable ranges.

Volt/VAR Control: (Also known as Volt/VAR Optimization) refers to the process of managing voltage levels by injecting or absorbing reactive power (measured in VAR) on the distribution system.