California Public Utilities Commission

California Smart Grid

Annual Report to the Governor and the Legislature

in Compliance with Public Utilities Code § 913.2

February 2017

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1. Executive Summary

This Annual Report on California's Smart Grid activities provides an overview of the California Public Utility Commission's (CPUC's) recommendations for a Smart Grid, the plans and deployment of Smart Grid technologies by the state's three largest Investor-Owned Utilities (IOUs),[1] and the costs and benefits to ratepayers, as estimated by the IOUs.[2]

Highlights of the 2016 CPUC Smart Grid-related activities include:

- CPUC Distributed Energy Resources (DERs)[3] Action Plan[4] – The Commission adopted a vision to support California's DER future in order to facilitate proactive, coordinated, and forward-thinking development of related DER policy.
- Distribution Resources Plan (DRP) – The Commission established collaborative working groups to help the IOUs develop methodologies for two analytic tools which will calculate available hosting capacity and identify optimal locations for DER deployment.
- Integrated Distributed Energy Resources (IDER) – The Commission approved a competitive solicitation framework and a utility regulatory incentive mechanism pilot which will facilitate the deployment of DERs to displace or defer the need for capital expenditures on traditional distribution infrastructure.
- Interconnection – The Commission issued a decision that directed significant improvements to Electric Tariff Rule 21[5] by streamlining and increasing the cost certainty of the interconnection process.
- Energy Storage – The Commission approved expediting 64.5 MW of storage to address reliability concerns posed by the shutdown of Aliso Canyon, and SCE procured an additional 20 MW of

[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." (Public Utilities (P.U.) Code § 913.2)

[3] DERs are defined in P.U. Code § 769 as renewable distributed generation, energy storage, demand response, energy efficiency, and electric vehicles.

[4] The DER Action Plan is available at the Energy Division's Energy Reports and Whitepapers page: http://www.cpuc.ca.gov/energy_reports/.

[5] Electric Tariff Rule 21 is the jurisdictional tariff governing the application and study process of interconnecting DERs to the three IOUs' distribution system.

utility-owned storage for similar purposes. Out of the 84.5 MW procured, 79.5 MW were brought online by January 2017.

- Electrification of Transportation – The Commission issued three separate decisions authorizing the IOUs to deploy charging infrastructure to support plug-in electric vehicles (PEVs).
- Demand Response – The CPUC's Energy Division began registering third-party demand response providers, to bundle retail customers and bid electric loads on the customers' behalf into the CAISO wholesale energy market.
- Enhanced Reliability Reporting – The Commission ordered the IOUs to increase reliability reporting, improving transparency as well as grid reliability and security assessment.

This report will detail the following:

- CPUC Smart Grid-related activities in 2016 (Section 2);
- IOU Smart Grid project reports and overall ratepayer costs and benefits. (Section 3); and
- CPUC Smart Grid activities that are expected in the coming year (Section 1.2.4.).

1.1. What is the Smart Grid?

The Smart Grid,[6] as defined in the State of California by Senate Bill (SB) 17 (Ch. 327, statute 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 electricity supply. The objectives in California, per SB 17 and P.U. Code § 8360 et al., 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;

[6] 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.

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

The CPUC has been working with California IOUs and the Legislature on numerous fronts throughout 2016 to advance grid modernization. The resulting initiatives are oriented towards making the grid in California smarter and safer, while reducing carbon emissions and improving reliability and resiliency.

1.2. California's Continuing Grid Modernization

Grid Modernization, or the process of installing Smart Grid technologies, has traditionally been a strategy of the IOUs where it has been economically feasible, and that strategy has been supported by the CPUC in General Rate Cases (GRC). Recent Grid Modernization efforts have built upon smart meter deployment, cost reductions in digital control and communications technology, power electronics, and advanced automation technologies that improve customer reliability and grid resilience.[7] However, the accelerating adoption of customer-side intermittent renewable generation, primarily solar photovoltaic (PV) systems, has produced new operational challenges and opportunities for the grid, which is driving the current need for IOU investment in Smart Grid technologies. Modernizing grid infrastructure, such that it serves as a beneficial platform rather than an impediment for customer adoption of distributed energy resources, is becoming a priority for the CPUC and the IOUs so that DERs can be interconnected to the grid in a "plug and play" manner.

A planned approach to increase Smart Grid investments is required to increase grid reliability and to reduce safety risk in the light of increasing customer adoption of DERs. The new Distribution Resources Plan proceeding now underway will guide new Smart Grid investment requests in future GRCs to meet these challenges.[8] 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. If properly planned for and deployed, DERs can potentially 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 as illustrated in the recently adopted DER Action Plan which seeks to align the Commission's vision and actions to shape California's distributed energy resources future. The DER Action Plan will serve 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 related DER policy.

1.2.1. Deployment Plan Background

The Commission adopted a number of decisions to further the state policy of Grid Modernization through implementation of the Smart Grid proceeding, including establishing that the IOUs file Smart Grid Deployment Plans annually. In 2014, the Commission closed the Smart Grid Proceeding, and ordered the IOUs' Smart Grid Deployment Plans to include the following eight elements:[9]

1. Smart Grid Vision Statement

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[7] 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).

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

[9] Decision (D).14-12-004.

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

The three IOUs filed their initial Deployment Plans on July 1, 2011, as required by SB 17. The Deployment Plans were approved by D.13-07-024 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.[10]

In 2014, the CPUC's Smart Grid proceeding was closed. Through succeeding decisions, the proceeding ordered the following:

- Required the IOUs to deploy smart meters and provide customers with smart meter-collected usage data;
- Required the IOUs to file Smart Grid Deployment Plans and to set the requirements for what the plans must address;
- Determined rules to protect the privacy and security of customer data generated by smart meters;
- Ordered the utilities to provide Home Area Networks (HAN) capability on the smart meters;
- Ordered the utilities to offer downloadable usage data to customers and authorized third parties, referred to as Customer Data Access (CDA);
- Adopted metrics to measure the effectiveness of smart grid investments; and
- Required an Energy Data Access Committee to determine ongoing access policies and issues.

[10] Each utility Smart Grid Annual report is available at: http://www.cpuc.ca.gov/General.aspx?id=4693.

The IOUs filed their 2016 Smart Grid annual reports in October 2016.[11]

1.2.2. Smart Grid Costs and Benefits

The three IOUs are required to report on Smart Grid program costs and associated benefits. Although progress has been made on standardizing reporting requirements among the three IOUs, there remains some divergence on how the IOUs represent environmental and customer benefits in monetary terms as well as which projects are Smart Grid-related. The costs and benefits shown in Table 1 below reflect the reporting period for the IOUs' Smart Grid Update Reports, which cover fiscal year 2015-2016 (July 1, 2015 through June 30, 2016). Costs are calculated as a 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 in the fiscal year with some exceptions.[12] The Commission will work to standardize project qualifications and cost-benefit analysis methodologies in the future.

Table 1 IOU Costs and Benefits for Fiscal Year July 1, 2015 through June 30, 2016

IOU	Smart Grid Costs ($Millions)	Smart Grid Benefits ($Millions)
PG&E	$455.35[13]	$ 68.30[14]
SDG&E	$107.10	$112.90
SCE	$ 73.88	$236.30[15]

1.2.3. 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 reducing the environmental impact of electricity production, transmission and distribution.

[11] The annual reports can be found on the CPUC website at: http://www.cpuc.ca.gov/General.aspx?id=4693.

[12] Benefits may include those accrued from previously completed projects and does not include all of the benefits that may be realized over the lifetime of the projects. Some Smart Grid projects may not have direct benefits yet may enable other programs.

[13] Of this total, $260.1 million represents the cumulative costs of one distribution automation and reliability project and one asset management and operational efficiency project incurred since the programs' inceptions.

[14] PG&E also reports non-monetized benefits of 49.4 million avoided customer outage minutes as a result of installing Smart Grid technologies.

[15] This total is primarily generated from monetized reliability benefits from SCE's Circuit Automation program, estimated using a Value of Service (VOS) reliability model developed by Lawrence Berkeley National Laboratory.

Pursuant to the goals of Assembly Bill (AB) 66 (Ch. 578, statute of 2013) which directed the IOUs to improve electric system reliability through greater accountability and enhanced reporting, the CPUC issued a decision in January 2016[16] that required reliability reporting on a more local basis by the IOUs. The IOUs were also directed to report 1% of their worst-performing circuits and to detail each year their investment plans for mitigating these reliability issues. Several Smart Grid technologies deployed by the utilities such as Geographic Information Systems (GIS), and Outage Management Systems, are expected to be deployed to mitigate reliability concerns and to automate and improve outage detection and mitigation while also improving reporting.

As the result of the CPUC's commitment to make safety an integral consideration in all of its proceedings, California's energy utilities in 2015-2016 have been refining their safety risk assessments in general rate cases (GRC). By identifying, prioritizing and offering mitigations for their top safety and operational risks, the utilities are providing the Commission with a stronger rationale for considering proposed GRC investments in infrastructure upgrades, improved training and safer operations. A top risk identified in the GRCs is the physical and cyber security of utility facilities. Increasingly, mitigation proposals involve new Smart Grid technologies that enhance safety, reliability and resiliency as well as improve monitoring of grid and pipeline operations, and distributed energy resources.

The CPUC also focuses on resiliency. Unlike reliability, which is well-defined with specific quantitative metrics (see Footnote 4), resiliency is more of an emerging Smart Grid attribute. Resiliency can be characterized as both the ability of the system to resist failure, and the ability to recover from events that cause outages. Improving the ability of the system to fully restore operations from a high stress situation or event is one of the objectives of many Smart Grid initiatives. Grid modernization initiatives generally enable the utility to develop situational awareness that anticipates problems using automated fault location, smart meters, and synchro-phasor measurements. Such information and technologies contribute to maintaining a more resilient grid by reducing the frequency and duration of outages and also enabling microgrids to operate in island mode.

1.2.4. Smart Grid Activities Expected in 2017 at the CPUC

Below is a list of some of the Grid Modernization and Smart Grid development projects anticipated in 2017:

[16] D.16-01-008 in R.14-12-014

- CPUC DER Action Plan – The CPUC's Energy Division will support the realization of the vision expressed in the CPUC DER Action Plan by forming a steering committee to coordinate implementation of the vision and goals of the Action Plan across multiple proceedings.
- Distribution Resources Plan - The Commission is likely to consider several proposed decisions (PDs) and project reports in the Distribution Resource Plan proceeding (R. 14-08-013), potentially on all three tracks in the proceeding. The DRP activities will address the analytic tools and methods, demonstration projects, and policy issues related to changing distribution system planning and investment practices to efficiently integrate high penetrations of DERs into the distribution grid. The IOUs have been directed to modernize the electric distribution system to accommodate two-way flows of DERs throughout their networks as part of the Commission's Grid Modernization guidance.
- Energy Storage - A proposed decision in the Energy Storage Proceeding (R.15-03-011) is scheduled in 2017. It is expected to address issues such as station power,[17] multi-use applications,[18] consideration of technology eligibility, community storage, and any adjustments to the storage target. The Commission will also initiate implementation of AB 2868 (Ch. 681, statute of 2016)[19] and AB 33 (Ch. 680, statute of 2016)[20] which requires the Commission to consider programs and investments to accelerate the widespread deployment of distributed energy storage paired with energy management systems, and analyze the ability of bulk energy storage projects to facilitate the integration of renewable generation, respectively.
- Interconnection - The Commission expects to open or designate a successor interconnection proceeding in 2017 to further streamline the interconnection process by leveraging the integration capacity analyses being developed in the utility Distribution Resource Plans proceeding (R.14-08-013). The Commission will also begin to implement AB 2861 (Ch. 672,

[17] Station power is the electricity consumed by a generating facility that is not directly related to the generation of electricity, including cooling systems and office equipment.

[18] Multi-use applications refers to the ability of storage devices to stack incremental value and revenue streams by delivering multiple services to the wholesale market, transmission system, distribution grid and end users.

[19] Effective January 2017, AB 2868 requires the Commission to direct the three IOUs to file applications for programs and investments to accelerate widespread deployment of distributed energy storage systems.

[20] Effective January 2017, AB 33 requires the Commission to evaluate and analyze the potential for all types of long duration bulk energy storage resources to help integrated renewable generation into the electrical grid.

statute of 2016), which authorizes the PUC to establish an expedited interconnection dispute resolution process that strives for binding resolution within 60 days.

- Smart Inverters - Pursuant to the Electric Tariff Rule 21 Interconnection proceeding (R.11-09-011), the adoption of smart inverter Phase 2 communications and Phase 3 advanced functionality into Rule 21 is expected in 2017. Phase 1 autonomous Smart Inverter functions adopted earlier will become mandatory in September 2017.
- Electrification of Transportation – Pursuant to SB 350 (Ch. 547, statute of 2015)[21] each IOU will file an application to propose programs and investments in transportation electrification (PG&E, SCE, and SDG&E will file in January and PacifiCorp, Liberty, and Bear Valley will file by June).
- Demand Response - The Commission will decide on the administration, design and implementation of advanced demand response (DR) products, and staff will begin assessing the success of the demand response auction mechanism (DRAM) pilot to ultimately determine if it should continue as a full program. A first-ever gas DR program will seek to address potential gas shortages in Southern California caused by the closure of the Aliso Canyon gas storage facility.
- General Rate Cases - The Commission is expected to complete PG&E's 2017 GRC (A.15-09-001), covering a number of Grid Modernization-related proposed investments.

2. Commission Activities Related to Smart Grid in 2016

2.1. Distribution Resources Plans

P.U. Code § 769[22] required the IOUs to file Distribution Resource Plans (DRPs) by July 1, 2015. The IOUs' filed DRP proposals that contained three primary analyses: 1) Integrated Capacity Analysis (ICA), which determines available grid capacity for DER interconnection on every circuit in the IOUs' service territories without additional upgrades; 2) Locational Net Benefits Analysis (LNBA), which identifies the optimal locations for the deployment of DERs to maximize distribution and ratepayer benefits; and

[21] SB 350 enacts the "Clean Energy and Pollution Reduction Act of 2015" and establishes targets to increase retail sales of renewable electricity to 50% by 2030 and double the energy efficiency savings in electricity and natural gas end uses by 2030, along with other objectives.

[22] Pursuant to Assembly Bill (AB) 327 (Ch. 611, statute of 2013).

3) DER Growth Scenarios, which forecast DER penetration under different market and policy assumptions. The IOUs' analyses are intended to identify high-value locations for DER deployment, as well as inform requests for distribution system and Smart Grid investments in the IOUs' GRCs to accommodate increasing penetrations of DERs. The CPUC must approve or modify the IOUs' DRPs in a way that minimizes costs of DER deployment and maximizes overall ratepayer benefits.

The primary goal of the DRPs is to develop new tools, processes, and investment frameworks that enable IOUs to better integrate DERs into grid operations and the annual distribution planning process. This broadly reflects the Smart Grid goals of grid modernization that includes greater customer choice, improved communications systems, and higher levels of automation to accommodate two-way energy flows. 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 P.U. Code § 769. New grid developments enabled under the DRPs will allow for higher penetrations of DERs and provide improved renewable integration capabilities. Many of the projects and activities envisioned as part of the DRP support a smarter, cleaner grid.

The Commission instituted a rulemaking, R.14-08-013, in August 2014 to evaluate the IOUs' July 1, 2015 DRP applications in accordance with the requirements of P.U. Code § 769. The DRP proceeding is considering the IOUs' July 1, 2015 DRP Applications across the following three tracks:

1. **Analytical/Methodological Issues**: Track 1 of the DRP is focused on developing the methodologies for two analyses that will identify optimal locations for DER deployment, including:
    a. **Integration Capacity Analysis (ICA)**: The ICA will determine the available hosting capacity of every circuit in the IOUs' service territories to accommodate additional DERs. ICA results will be published through online maps and downloadable datasets on the IOUs' websites and will likely be updated on a monthly basis. The ICA will help DER developers site projects in grid locations that are unlikely to trigger system upgrades; will be used by the IOUs in the annual distribution planning process; and will serve as the basis for a streamlined (and potentially automated) Rule 21 interconnection process.
    b. **Locational Net Benefits Analysis (LNBA)**: The LNBA will determine the optimal location for DER deployment based on opportunities for DERs to cost-effectively defer or avoid traditional distribution system investments. Public LNBA results will

be published in online maps, while the IOUs will also evaluate LNBA results as part of the annual distribution planning process, which will then inform DER sourcing activities being determined in the Integration of Distributed Energy Resources (IDER) proceeding (R.14-10-003).

The ICA and LNBA methodologies are being honed through collaborative multi-stakeholder working group processes. The working groups meet frequently and will submit short- and long-term deliverables in January 2017 and June 2017, respectively.

2. **Demonstration and Deployment Projects (Ratesetting):** Track 2 of the DRP entails five Demonstration and Deployment Projects that aim to verify the IOUs' ability to plan and operate the distribution system around increasingly high DER penetrations, including:
   - **a. Demo A:** Implement the ICA for a selected Distribution Planning Area (DPA);
   - **b. Demo B:** Implement the LNBA for a selected DPA;
   - **c. Demo C**: Source DER(s) to defer a traditional infrastructure investment and provide net benefits;
   - **d. Demo D**: Operate the system at high penetrations of DERs; and
   - **e. Demo E**: Plan and operate a microgrid.

A Track 2 Commission decision is expected in early 2017 to consider various aspects of the IOUs' demonstration projects as originally proposed in their July 1, 2015 applications and further elaborated on in detailed plans filed June 2016.

3. **Policy Issues**: Track 3 of the DRP deals with a number of policy questions related to incorporating new tools and forecasting methods into existing distribution system planning and investment processes:
   - a. **Sub-track 1 – DER Growth and Distribution Load Forecasting**: This sub-track will examine methodological issues for developing spatially granular forecasts of DER adoption and distribution load for purposes of the DRP, as well as process alignment with the CEC's Integrated Energy Policy Report (IEPR), Integrated Resources Planning (IRP), Long-Term Procurement Planning (LTPP), and the CAISO's Transmission Planning Process (TPP).
   - **b. Sub-track 2 – Grid Modernization Investment Framework**: This sub-track is aimed at developing a framework for identifying cost-effective investments in grid

modernization technologies that allow utilities to better plan and operate the grid at high penetrations of DERs.

c. **Sub-track 3 – Distribution Investment Deferral Framework**: This sub-track is aimed at development of a framework for evaluating LNBA results as part of the annual distribution planning process to select opportunities for DERs to defer or avoid traditional distribution investments. Process alignment between the distribution planning process, the capital planning process, and the General Rate Case process will also be considered for the purposes of the Deferral Framework.

An October 21, 2016 Assigned Commissioner's Ruling formally set the above scope of Track 3, which commenced in December 2016 with a workshop on Sub-track 3.

2.2. Integrated Distributed Energy Resources (IDER)

Since 2007 the CPUC has sought to integrate distributed energy resources (DERs) through utility program offerings (e.g., Energy Efficiency, Demand Response) and more recently, through the Integrated Distributed Energy Resources (IDER) proceeding. The Commission's intent is to integrate these resources and technologies in order to reduce GHG emissions and increase ratepayer benefits by displacing planned traditional capital investments in "wires" solutions.

On December 15, 2016, the Commission adopted Decision 16-12-036, which approved a competitive solicitation framework and a utility regulatory incentive mechanism pilot which will facilitate on a pilot basis the deployment of DERs to displace or defer the need for capital expenditures on traditional distribution infrastructure. . In order to test the incentive mechanism, the Utilities are encouraged to select up to three distribution deferral projects for piloting. For purposes of the Incentive Pilot, the Commission adopted a 4% pre-tax incentive which will be applied to the annual payment for the DERs that are procured as an alternative to traditional distribution project investments. The decision required the IOUs to form a Distribution Planning Advisory Group (DPAG) who will be advising them on selection of distribution deferral opportunities and providing input on the development of competitive solicitations for DERs. Members of the DPAG will include market participants and one Independent Professional Engineer who is tasked with evaluating distribution plans for the Incentive Pilot.

The decision also re-established the Competitive Solicitation Framework Working Group who along with the CPUC Energy Division and an Industry Consultant is tasked with developing a technology-neutral pro forma contract for future use.

2.3. Interconnection Reform

In 2016, the CPUC oversaw significant progress in improving Electric Tariff Rule 21, the CPUC jurisdictional tariff governing the application and study process for DER interconnection, as well as the development of advanced inverter functionality and communications.

An active stakeholder process within the Interconnection Rulemaking (R.11-09-011)[23] focused on two primary goals: 1) enhancing the predictability and certainty of interconnection upgrade costs, aka "Cost Certainty''; and 2) standardizing and streamlining Rule 21 interconnection for non-exporting, behind-the-meter energy-storage devices. In the fall of 2015, the CPUC's Energy Division facilitated a series of stakeholder workshops that resulted in November 2015 joint-party proposals that entailed the following:

1. Expansion of the Rule 21 Pre-Application Report to provide prospective applicants with higher resolution data on site and system components than the currently available report;
2. Publication of a distribution Unit Cost Guide to provide applicants with insights into illustrative component costs for typical system upgrades that are triggered by interconnection applications;
3. Improvements in the transparency surrounding how information on energy storage charging behavior is collected and studied in the Rule 21 application process;
4. Creation of an expedited interconnection application and a study process for certified, standardized non-exporting storage configurations;
5. Revisions to Rule 21 to deem the use of certified converter technology that physically prevents back feed to the grid to be sufficient to obviate the need for an interconnection study; and
6. Creation of an additional inadvertent export option that utilizes advanced inverter functionality to maintain acceptable levels of safety and reliability.

These proposals, along with a 125% cap on developer responsibility for system upgrade costs (i.e., 125% of the initial cost estimate known as the "Cost Envelope"), were adopted in D.16-06-052 in June 2016. These proposals work to enhance the DER interconnection process and will make it easier for customers to interconnect the DER technologies that grid modernization efforts are intended to accelerate.

2.4. Smart Inverters

Smart Inverters enable communications and control of networked DERs and represent one of the foundational building blocks of the Smart Grid. Smart inverters' primary benefit is to increase the

[23] R.11-09-011 - Establishing Distribution-Level Interconnection Rules for Certain Generators and Storage.

capacity of the distribution system to accommodate higher penetrations of DER by mitigating some of the grid impacts of intermittent variable resources and enhancing these same DERs' ability to serve as grid assets for improved operation of the grid. The advanced inverter functionality standards that have been developed in the Smart Inverter Working Group (SIWG) will ultimately be incorporated into the Rule 21 tariffs.

Following the Commission's adoption of seven autonomous Phase 1 smart inverter functions per D.14-12-035 in R.11-09-011, the SIWG, in February 2015, submitted its recommendations for Phase 2 communication protocols. These recommendations include a proposal that Rule 21 require all interconnected DERs to be capable of communications, with IEEE 2030.5[24] serving as the default protocol used by IOUs to communicate between individual DERs, facility DER management systems, and DER aggregators.

Furthermore, the SIWG finalized its recommendations for a number of additional Phase 3 smart inverter functions in March 2016. These advanced functions represent higher levels of DER dispatch and control and are necessary for leveraging DERs for grid operations and planning in the Smart Grid of the future (as is being contemplated in both the DRP and IDER proceedings).

The Commission directed the IOUs to propose Rule 21 tariff revisions based on the SIWG's recommendations for Phase 2 communications and Phase 3 advanced inverter functions in D.16-06-052. Rule 21 tariff revisions setting forth updated inverter design requirements based on these new capabilities were due December 20, 2016. Additional development of these advanced functions will continue in 2017, but such capabilities will not be mandatory for new DER installations for a few years following tariff revisions, to allow for industry-accepted testing and certification programs to be established.

2.5. Energy Storage

The Commission's energy storage procurement policy was formulated to reduce peak-energy demand, enhance reliability, defer transmission and distribution upgrade investments, integrate renewable energy, and reduce greenhouse gas emissions through the utilization of energy storage devices. In this way, energy storage can be seen as a crucial backbone of the Smart Grid. The Commission established storage procurement targets in 2013 of 1,325 MW to be procured by 2020 and operational by 2024.

[24] Also known as Smart Energy Profile (SEP) 2.0 Application Protocol Standard.

In December 2014, the CPUC, California Independent System Operator (CAISO), and the California Energy Commission (CEC), after consultation with 400 interested parties, including utilities, energy storage developers, generators, environmental groups, and other industry stakeholders published "Advancing and Maximizing the Value of Energy Storage Technology-A California Roadmap."

This Storage Roadmap focuses on actions that address three categories of challenges expressed by stakeholders:

- Expanding revenue opportunities;
- Reducing costs of integrating with and connecting to the grid; and
- Streamlining and identifying policies and processes to increase certainty.

In 2015, the three IOUs progressed with their energy storage bid solicitation processes to satisfy their required energy-storage procurement targets on their way towards the larger target of procuring 1,325 MW of cost-effective storage. The results from the 2014 procurement cycle were filed in December 2015. In March 2016, the three IOUs filed applications for their 2016 storage procurement. Following briefs and comments, the Commission adopted the plans in September 2016.

On April 2, 2015, the Commission opened a Rulemaking[25] to continue to refine policies and programs as required by previous decisions that established the Energy Storage Procurement Framework and approved the utilities' applications implementing the program. This current storage policy proceeding will also address policy and implementation questions identified in the Storage Roadmap. In January 2016, the Commission adopted its first decision in R.15-03-011, which covered Track 1 issues. These issues are: storage procurement best practices, flexibility of storage targets between grid domains, cost recovery, safety standards, and technology eligibility. In May 2016, the Commission held three workshops to inform Track 2 issues – station power, multi-use applications, and cost recovery/power charger indifference adjustment (PCIA). Parties filed post-workshop comments and reply comments on station power and multi-use application workshops.

In addition to the aforementioned Rulemaking activities, SCE and SDG&E also held expedited procurements for energy storage facilities to address reliability concerns caused by the shutdown of Aliso Canyon. On May 26, 2016, the Commission adopted Resolution E-4791, which ordered the expedited procurement, and required that the projects be operational by December 31, 2016, be located in front of

[25] R.15-03-011

the utility meter, be price competitive, qualify for resource adequacy credit and have a contract term of no more than 10 years. On September 15, 2016, the Commission adopted Resolution E-4798, which approved a 37.5 MW utility-owned storage project for SDG&E. On September 29, 2016, the Commission adopted Resolution E-4804, which approved 27 MW of capacity-only contracts, 22 MW of which successfully were energized by December 31, 2016. SCE has also developed a 20 MW utility-owned storage project with Tesla, which also came on-line by the last day of 2016.

2.6. Plug-In Electric Vehicle Integration

Beginning with R.08-12-009, the Commission began exploring the potential for plug-in electric vehicles to interact with an increasingly modernized grid. The concept known as Vehicle-Grid Integration (VGI), harnesses the storage capabilities of electric vehicles to act as a "grid asset" to provide grid services through an interoperable market integrated with the Smart Grid.

The CPUC's activities related to PEVs are broadly categorized into four areas:

1) Infrastructure deployment
2) Rates
3) Rebates and incentives
4) Vehicle-grid integration

Smart Grid-related activities are mainly tied to the VGI category. VGI can be broadly defined as leveraging PEVs as a grid resource in a way that maximizes customer, grid, and environmental benefits and leads to increased PEV adoption.

In 2016, the CPUC issued decisions authorizing SDG&E,[26] SCE,[27] and PG&E[28] to deploy charging infrastructure to support PEVs. The three IOU pilots will install the infrastructure to support up to 12,500 charging stations with total budgets of $197 million. The IOUs will install charging infrastructure in multi-unit dwellings, workplaces, and some public locations. SCE's pilot will install and own the "make ready" infrastructure, but the site host will purchase and own the charging station. SDG&E will own all infrastructure including the charging station. PG&E's pilot is a hybrid approach: they may own the

[26] D.16-01-045

[27] D.16-01-023

[28] D.16-12-065

charging stations only if the site host is in a multi-unit dwelling or disadvantaged community, and they may only own up to 35% of the total charging ports deployed through the pilot.

Throughout 2016, the CPUC also began implementing SB 350 (Ch. 547, statute of 2015), which, among other things, ordered the CPUC to direct the six electric investor-owned utilities to file applications for programs and investments to accelerate widespread transportation electrification. The Commission held a workshop, received stakeholder input, and issued guidance to the utilities[29] about what types of programs and investments they should propose in their applications. The Commission will begin receiving utility applications in January 2017.

Related to VGI, the Commission's Energy Division oversees the administration of PEV-related research projects that are funded by the Electric Program Investment Charge (EPIC) in addition to other utility research projects.

2.7. Demand Response

The electric power industry considers demand response an increasingly valuable resource option that has capabilities that are beneficial to grid-modernization efforts. Demand Response facilitates renewable integration and load balancing while minimizing the operational cost of the Smart Grid. Demand response (DR) is a valuable tool in meeting California's progressive renewable targets while maximizing grid efficiency and operation.

The role of DR in facilitating renewable integration in 2020 and 2025 is underscored by a study commissioned by the CPUC and executed by the Lawrence Berkeley National Laboratory, entitled the "2015 California Demand Response Potential Study: Charting California's Demand Response Future."[30] The study is part of the Commission's DR proceeding R.13-09-011, which has a purpose of initiating action to determine the feasibility of bifurcating current DR programs into demand-side and supply-side resources. The study's breakthrough methodology draws on Advanced Metering Infrastructure (AMI) data from more than 200,000 customers to create hourly load shapes disaggregated by end uses, including electric vehicles. The study forecasts levelized cost supply curves that illustrate the technical potential, availability and cost-competitive potential for DR to provide four services.

[29] D.16-11-005

[30] The report is available on the CPUC Demand Response Evaluation and Research page: http://www.cpuc.ca.gov/General.aspx?id=10622.

In D.16-09-056, the Commission maintains the role of Investor Owned Utilities (IOUs) as both administrators and implementers of traditional peak shedding DR programs by allowing the IOUs to continue to procure DR up to 2017 budget levels through a 2020 mid-course review. At the same time, the decision fosters its support of third parties by capping the IOU DR portfolios at 2017 budget levels and requiring the IOUs to procure all additional DR from third parties through the Demand Response Auction Mechanism (DRAM), if the DRAM pilots are found to be successful. (Pilot DRAM contracts with third parties were expected to deliver 40.5 MW in August 2016 and an additional 124.6 MW in August 2017.) A major tenet in D.16-09-056 is to provide customers an open and fair market to choose among DR provider options, to enable competitively-set capacity prices, and, for the IOUs to provide a level playing field for third parties competing with them. In other actions, the decision sets a five-year portfolio cycle from 2018-2022, and identifies the need to handle new, fast and flexible DR in a future decision and separate portfolio application. In a precedent-setting action, the decision prohibits the use of several types of backup generation as a means of providing demand response beginning in 2018.

There were two major developments in 2016 in the implementation of Electric Rule 24 (known as Rule 32 for SDG&E), which establishes the terms and conditions for providers who wish to take part in direct participation demand response service. Energy Division began registering third party DR providers and facilitated a working group that is developing a “click-through” solution to allow customers to authorize release of their energy use data in a more streamlined fashion. The Electric Rule 24 tariff allows bundled customers to bid their load curtailment directly into CAISO wholesale energy markets, without going through the IOUs, if they are large enough, or to aggregate with other customers under a DR provider if they are not. Rule 24 supports the D.16-09-056 objectives for an open and fair market of providers that customers can choose among.

Pursuant to Commission Decision D.12-11-025, competitive Demand Response Providers are required to register with the CPUC.[31] A CPUC-registered DR Provider is authorized to provide Demand Response service(s) to bundled retail customers of the three largest IOUs to bid electric loads on their behalf into the CAISO wholesale energy market. Registering DR Providers discourages bad actors from participating in this new market and the performance bond required for DR Providers serving small bundled customers (<20kW) protects them from financial harm.

[31] More information including how to register can be found at: http://www.cpuc.ca.gov/General.aspx?id=8314.

2.8. Enhanced Reliability Reporting

Enhanced reliability reporting provides an objective standard and information to foster continuous improvement of reliability issues. The R.14-12-014 proceeding focused on interpreting and implementing requirements in P.U. Code § 277.1. D.16-01-008 in R.14-12-014 directs the utilities to use the reliability reporting template at Appendix B of the decision to report reliability data to the Commission on July 15 of each year.[32] Reliability data will be reported at the system level as well as division or district level. The recent decision requires sustained reliability deficiency in an area to be based on two to three years of consistently poor performances.[33] The three IOUs will report 1% of their worst-performing circuits, while PacifiCorp, Liberty Utilities, and Bear Valley Electric Service will report their three-, two-, and one-worst performing circuits, respectively. Current reporting requirements and new reliability reporting requirements will be combined into a single report. All utilities are required to include remediation plans to improve their worst-performing circuits and to explain the justification of these plans in their reports.

The decision also allows customers to request reliability information about their circuits via utility websites and to receive responses in a timely manner. All utilities will conduct at least one annual public in-person presentation about the information in their annual electric reliability reports and make webinar participation available. However, utilities would not have to provide specific reporting to monitor service of essential customers. Furthermore, electric utilities are developing a joint proposal to consolidate different reliability reporting requirements from Commission decisions and General Orders into a single Commission decision and General Order. The Commission expects this consolidation effort to begin in 2017.

Enhanced reliability reporting will help the state's grid modernization efforts by increasing transparency into the reporting metrics for reliability standards and will describe the remediation efforts the IOUs are taking to target and address the worst performing circuits. It will ultimately serve as an assessment tool to measure the progress in grid reliability and security improvements as indicated in SB 17 and P.U. Code § 8360.

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

[33] Exception would be made for system-wide district level data, which will be excluded in a major event day.

2.9. Customer Data Access, Energy Data Request, and Other Data Activities

The Commission's Smart Grid proceeding envisioned leveraging and optimizing the benefits of AMI data to inform diverse and expanding offerings in distributed energy management, such as customer solar, energy efficiency, electric vehicles, demand response, time-variant pricing, and energy storage. Numerous utility data access approaches are required to accomplish these goals.

There are challenges associated with the IOUs' rollout of customer data access programs that Commission Staff is working to address. Utility data access is a relatively new area of public policy, and some of the IOUs have been restrictive regarding the data they will release to customers and to customer-authorized third parties; furthermore, some IOUs have been slow to address IT issues that support these online data access platforms. While progress has been made in some areas, the overall data access process can be slow and cumbersome for some users. As a result, a variety of technical "workarounds" have been developed by market participants to gain access to data needed to provide customer services. Several initiatives are underway in 2017 to improve IOU data access platforms in order to meet the needs of ever-evolving customer energy service offerings. This includes an online Customer Information Service Request (CISR) form, automated "click through" customer authentication, expansion of data available for different levels of access, timely availability of data, and a streamlined customer experience to improve transactional efficiencies.

Energy Data Request Process (EDRP)[34]

The Commission established rules and a process that provides access to energy usage and usage-related data while protecting privacy of personal data (D.14-05-016). The Energy Data Request Process (EDRP) is different from customer data access CDA programs, which serve customers or customer-authorized third parties, in that it enables utility data access based on different use cases, each with different levels of aggregation and security considerations. The IOUs maintain EDRP program information on their web pages and email addresses for the public to efficiently access information and to request applications.

To request energy data, parties must complete an application that lists the details of their request. The details of requested data are varied, but according to the decision guidelines all customer energy use data must be anonymized and aggregated at specified levels according to the needs of each market sector

[34] Links to the utility energy data request websites can be found at: http://www.cpuc.ca.gov/General.aspx?id=10151.

(residential, commercial, agricultural, industrial). Numerous procedural safeguards are in place to ensure customer privacy and to adhere to the best data privacy practices.

Energy Data Access Committee (EDAC)

The data access decision also established the Energy Data Access Committee (EDAC), a non-adjudicatory body responsible for advising the Commission on data request issues that arise from the EDRP. The EDAC, which meets quarterly, is comprised of representatives from each of the IOUs, the CPUC, the Office of Ratepayer Advocates (ORA), CEC, local governments, consumer privacy advocates, academic researchers, and rotational interested parties.

One of the biggest concerns put before the EDAC comes from local governments that require utility data to complete greenhouse gas (GHG) inventories under locally-mandated climate action plans. Numerous representatives from city and county planning offices have complained about the quality of the data provided, which show drastic irregularities since the Commission decision and new data aggregation rules went into effect in 2014. Impacts of the Commission's privacy rules on utility data provided to these communities have hampered local climate action plan reporting obligations. These issues were brought to the EDAC's attention at the quarterly meeting in March, 2016, and the committee began a study of the problem. The EDAC created a formal subcommittee comprised of EDAC members and relevant stakeholders to develop a recommendation for a GHG Inventory Use Case, with appropriate data specifications, for Commission adoption. The subcommittee expects to have a formal recommendation from the EDAC to the Commission in early 2017.

2.10. Conversion of Master Metering and Submetering to Direct Metering

The Commission's efforts to phase out master-metering and sub-metering and replace them with direct utility metering[35] will bring the benefits of smart meters to more customers and raise customer awareness of their electrical usage and costs.

The Commission adopted D.14-03-021 to implement tariffs in a three-year pilot program for voluntary conversion of electric and natural gas master-metered services at mobile home parks and manufactured housing communities (collectively, MHPs) to direct services by electric and/or gas corporations. Electric and gas utilities are ordered to convert approximately 10% of the MHP spaces in each of their service territory by the end of 2017. Each utility shall submit a report by February 1, 2018,

[35] By default, the replaced meters will be smart meters unless a customer opts out.

providing comprehensive cost accounting of construction based on project completions. The Commission may use these reports to assess and determine the future course of the conversion program.

3. Smart Grid Projects in California

3.1. Summary of IOU Activities in 2016

The State of California and the California IOUs continued to advance Smart Grid development begun in 2009 pursuant to SB 17. Utility activities in these categories are reported in the Smart Grid Annual Reports,[36] which are filed by the IOUs each October, per D.10-06-047, and are organized into the categories below:

- Customer Empowerment;
- Transmission and Distribution Automation/Utility Operations;
- Cyber and Physical Grid Security;
- Integrated and Cross-Cutting Systems; and
- Asset Management, Safety and Operational Efficiency.

The IOUs are also required to report the monetary value of benefits derived from Smart Grid activities. The methodology for calculation of benefits is similar among the three utilities. However, there are still some differences in methodology. The costs and benefits shown below were accrued during the reporting period of the 2016 IOU annual update reports, which is from July 1, 2015 to June 30, 2016.

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 stemming 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 vehicles were noted. Other benefits include operational, reliability, and demand response/energy conservation. Smart Grid investments continue to contribute to a safe, reliable, resilient, and sustainable grid.

[36] The annual reports can be found on the CPUC website at: http://www.cpuc.ca.gov/General.aspx?id=4693.

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 such information as energy usage, rates, energy conservation, and peak-load reductions. Using this information, customers will be empowered to better manage 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 Home Area Networks (HAN) 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 wide-area monitoring, protection, and control to allow grid operators the tools necessary to monitor bulk power system conditions, safely and reliably incorporate utility-scale intermittent power generation, and 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" benefits, and provide optimization of voltage and reactive power to enhance power quality and decrease energy consumption. TAR and DAR help to deliver a Smart Grid that has the infrastructure necessary to support the integration of demand response, energy efficiency, distributed generation and energy storage.

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

4.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 using 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, maximizing the value of these technology investments.

5.Asset Management, Safety, and Operational Efficiency

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

3.1.1. Advanced Metering Infrastructure Deployment

Table 2 Advanced Metering Infrastructure (aka Smart Meters) Rollout[37]

IOU (as of Oct. 2016)[38]	Total Number of Electric Smart Meters (Millions)	Electric Smart Meter Opt-outs (No. of customers)	Percentage of Opt-outs	Customer Complaints (escalated)[39]
PG&E	5.51	53,397	0.96%	8
SDG&E	1.44	2,775	0.19%	0
SCE	5.08	21,415	0.42%	469
Total	12.03	77,587	0.64%	477

Source: IOU Data Requests

[37] 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.

[38] The reporting period is from November 1, 2015 to October 31, 2016.

[39] Escalated complaints are customer complaints regarding smart meters that have gone through the complaint process and reached resolution. The number of escalated complaints decreased from last year's level.

In 2007, with Commission approval, the IOUs began full deployment of Advanced Meter Infrastructure, which was largely completed in 2013. Electric opt-outs refer to customers who have declined to adopt smart meters. Customer complaints have decreased over the past few years.

3.2. Highlights of San Diego Gas & Electric's (SDG&E) Smart Grid Deployment

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

Costs

Table 3 SDG&E's Estimated Smart Grid Costs for Fiscal Year July 1, 2015 through June 30, 2016

Task	Value
Customer Empowerment and Engagement	$44,757,000
Distribution Automation and Reliability	$19,983,000
Transmission Automation and Reliability	$4,204,000
Asset Management, Safety and Operational Efficiency	$7,019,000
Security	$15,382,000
Integrated and Cross-Cutting Systems	$15,776,000
Total Estimated Costs	$107,121,000

Benefits

Table 4 SDG&E's Estimated Smart Grid Benefits Realized for Fiscal Year July 1, 2015 through June 30, 2016

Benefit	Value
Economic Benefits	$36,478,000
Reliability Benefits	$33,316,000
Environmental Benefits	$13,838,000
Societal Benefits	$29,311,000
Total Estimated Benefits	$112,943,000

Highlights of SDG&E's Smart Grid deployment update include:

- Becoming the first major California utility to reach the net metering cap of 5% of peak demand at 617 MW on June 29, 2016;

- CPUC approval of the company's EV Grid-Integration pilot program, which will provide the customer a price signal based on grid conditions and will allow SDG&E to own and install up to 3,500 EV charging stations at businesses and multi-family residences;
- Installation of approximately 3,700 Renewable Meter Adapters (RMA), which allows rooftop solar projects to directly connect to existing electric meter paneling, reducing the time and cost of residential solar installations;
- Plug-in electric vehicle growth of 21,000 vehicles, which is 4,000 more than the previous year.

3.2.1. SDG&E Example Projects

- **Demand Response Management System (DRMS)** – The DRMS project enables integrated management of SDG&E's entire demand response portfolio. This includes program management, device management, forecasting, and analytics/reporting. The final release for Phase 1 was deployed in Q3 2016.
- **Supervisory Control and Data Acquisition (SCADA) Capacitors** – This project aims to convert existing distribution line capacitors to SCADA control to increase reliability, minimize downtime, and expedite repair work. Fourteen capacitors were converted during the reporting period.
- **Advanced Distribution Management System (ADMS)** – The purpose of this project is to implement new functions within the new Outage Management System/Distribution Management System (OMS/DMS) to better manage the electric distribution grid. Phase 2 of the project, which was implemented in the reporting period, focused on modeling and integrating DERs into DMS to improve power flow forecasts, enhance functionality, and provide transparency to the impacts these assets present to the distribution grid. Phase 3, which is currently being implemented, provides the ability to view feeder load management results for any device on the system and improves Fault Location Isolation and Service Restoration (FLISR) configurations.
- **Unmanned Aircraft System (UAS)** – The objective of the program is to research and evaluate use cases for unmanned aircraft systems. The team has created materials for UAS operations and tested the live streaming capability of the Emergency Operations Center. Local UAS commercial contracting services are being researched to support some newer technologies and provide flights for large projects within the company.

3.3. Highlights of Southern California Edison (SCE) Smart Grid Deployment

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

Costs

Table 5 SCE's Estimated Smart Grid Costs for Fiscal Year July 1, 2015 through June 30, 2016

Task	Value
Customer Empowerment and Engagement	$ 9,960,000
Distribution Automation and Reliability	$ 35,968,000
Transmission Automation and Reliability	$8,730,000
Asset Management, Safety and Operational Efficiency	$1,828,000
Security	$6,311,000
Integrated and Cross-Cutting Systems	$11,082,000
Total Estimated Costs	$73,879,000

Benefits

Table 6 SCE's Estimated Smart Grid Benefits Realized for Fiscal Year July 1, 2015 through June 30, 2016

Benefits	Value
Operational Benefits	$9,100,000
Reliability Benefits[40]	$208,900,000
Demand Response/Conservation Benefits	$18,300,000
Total Benefits	$236,300,000

Highlights of SCE's Smart Grid deployment update include:

- Development of a Grid Modernization plan to accelerate the widespread installation of modern automation and control capabilities on distribution circuits and substations;

[40] Estimated using Value of Service Model developed by the Lawrence Berkeley National Laboratory on circuit automation reliability program, which shortens the amount of time required to restore power to a portion of customers during an outage. The benefits have accrued since program inception which was initiated approximately two decades ago.

- Continued implementation of projects aimed at effectively managing plug-in electric vehicle loads and accommodating customer adoption of time-variant PEV rates;
- Continued implementation of projects to increase the communication capabilities of the distribution network including communication between control centers;
- Transition from development and initial deployment to regular procurement of cybersecurity products that improve management of the reliability risks of Smart Grid deployments;
- Coordination with standards entities to develop, evaluate, and implement open standards for Smart Grid technologies.

3.3.1. SCE Example Projects

- **3rd Party Smart Thermostat Program** – SCE is working with some of the leading Internet connected smart thermostat vendors and system providers to enroll customers in a demand response program that utilizes smart meter interval data. After the two-year study in 2013 and 2014, SCE started the Save Power Day program in June 2015 and has approximately 9,000 participants enrolled as of September 2016.
- **Distribution Energy Storage Integration (DESI) Program** – The DESI program aims to advance understanding of energy storage system deployment and the value it brings to local distribution circuits. One of the three projects is operational and the other two will be operational in 2017.
- **Advanced Technology Fenwick Labs** – SCE started the Advanced Technology Fenwick Labs in 2011 to provide an integrated platform for evaluating the safety and operability of Smart Grid technologies without impacting customers by testing on distribution circuits or other equipment. Over the last reporting period, the laboratories have tested innovation related to communications and computing, substation automation, distributed energy resources, controls, power systems, and other equipment and tools for the benefit of the grid.
- **Charge Ready Program** – The Charge Ready Program is an initiative to deploy electric vehicle charging stations at locations where EVs will be parked for four or more hours, such as multi-family dwellings and workplaces. SCE also conducts market education to develop awareness of EVs and the benefits they provide to the grid. Approval from the Commission was granted in April 2016, and SCE is in the process of receiving applications for the pilot program and launching its market education efforts.

3.4. Highlights of Pacific Gas & Electric (PG&E) Smart Grid Deployment

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

Costs

Table 7 PG&E's Estimated Smart Grid Costs for Fiscal Year July 1, 2015 through June 30, 2016

Task	Value
Customer Empowerment and Engagement	$34,205,000
Distribution Automation and Reliability[41]	$183,810,000
Transmission Automation and Reliability	$56,640,000
Asset Management, Safety and Operational Efficiency[42]	$127,490,000
Security	$10,400,000
Integrated and Cross-Cutting Systems	$42,800,000
Total Estimated Costs	$455,345,000

Benefits[43]

Table 8 PG&E's Estimated Smart Grid Benefits Realized for Fiscal Year July 1, 2015 through June 30, 2016

Benefits	Value
Direct Customer Savings	$700,000
Avoided Costs	$5,100,000
Customer Reliability Costs	$62,400,000
Total Cost Savings	$68,300,000
Avoided Outage Minutes[44]	49.4 million minutes

[41] This figure includes $142.4 Million for the Distribution SCADA program incurred since program inception. $42 Million were incurred during the reporting period.

[42] This figure includes $117.7 Million for the Electric Distribution Geographic Information System and Asset Management Project incurred since project inception.

[43] Measured as incremental savings where customers receive direct financial, environmental, reliability and societal benefits from the projects and benefits to the utility from improved safety and reduced operational costs.

[44] This metric was not provided in SCE's and SDG&E's Annual Smart Grid Reports.

Highlights of PG&E's Smart Grid deployment update include:

- Continued implementation of demand response and electric vehicle integration projects including the DR plug-in electric vehicle (PEV) Pilot in collaboration with BMW;
- Continued implementation of distribution and transmission automation projects, such as distribution level SCADA and Smart Grid Fault Location, Isolation, and Service Restoration (FLISR);
- A focus on leveraging industry-standard technologies to capture and provide access to accurate, traceable, and verifiable grid asset information;
- Implementation of the Identity and Access Management Project, which aims to strengthen system access controls and reduce the risk of unauthorized access to PG&E's system.

3.4.1. PG&E Example Projects:

- **Energy Diagnostics and Management (ED&M)** – The ED&M Project is the implementation of a comprehensive strategy for customer self-service demand-side management, which includes launching new tools to help customers understand how they use and generate energy, their energy bills, and savings opportunities. ED&M aspires to create aware and engaged customers through actionable information and personalized recommendations.
- **Battery Energy Storage System (BESS) Demonstration Projects –** The energy storage projects have been used to gain "real world" experience and data from participation in the CAISO market and to mitigate overload conditions on distribution system equipment. PG&E is testing the operational and integration capabilities of grid-scale storage batteries to better understand the benefits to the utility of integrating storage and usage in the overall supply market and distribution system. PG&E expects to have completed the final report by the end of 2016.
- **Smart Grid Line Sensors Pilot** – The pilot aims to test how line sensors can provide more accurate information about faults and outage restoration as well as current flow for operators and engineers to base operations and planning on measurements instead of models. The Smart Grid Line Sensor project improves reliability and increases the capability of the distribution system.
- **Smart Grid Short-Term Demand Forecasting Pilot Project** – The goal of this project is to evaluate if more granular data can be acquired and used to enhance PG&E's short-term electricity demand forecasts for retail load. Phase 3 involves forecasting hourly loads for the identified local

areas on a 7 day by 24 hour basis, analyzing the model performance, and evaluating the new forecasting methodology for system-wide deployment. PG&E expects to have completed the project by the end of 2016.

4. 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. The programs and projects implemented have realized $417 million in benefits in Fiscal Year 2015-2016. However, as indicated by the DER Action Plan, California still has more to do to realize the vision of a smart and modern grid. This will require the coordination of many efforts related to distributed energy resources including: electric vehicles, distribution resource planning, demand response, storage, retail rates, and interconnection. By fulfilling the vision of the Action Plan we will help move California towards a sustainable, affordable, efficient, and effective grid of the future. 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.

CPUC Smart Grid Vision

With 5,000 MW of customer-sited solar on California's grid, nearly 300,000 electric vehicles on California's roads, and accelerating adoption of battery storage, California's utilities must be prepared to manage a rapidly evolving grid while meeting California's ambitious greenhouse gas goals. To that end, the CPUC achieved several noteworthy accomplishments in 2016 to meet the Smart Grid goals that the Legislature set for us. The Commission endorsed a DER Action Plan that guides our Smart Grid and distributed energy resources (DERs) activities in numerous ongoing and upcoming proceedings on rates, grid planning and operations, and DER wholesale market participation. In addition, the CPUC approved several important decisions related to utility investments in electric vehicle charging infrastructure, enabling DERs to provide grid services, facilitating interconnection of DERs, adopting smart inverter standards, and authorizing hundreds of megawatts of new battery storage facilities. In the year ahead, we will continue to make significant progress in these areas and others that improve electricity reliability and resiliency while protecting the environment.

- Michael Picker, President, California Public Utilities Commission, January 2016.