California Public Utilities Commission

California Smart Grid

Annual Report to the Governor and the Legislature

in Compliance with Public Utilities Code 913.2

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1. Executive Summary

Pursuant to Public Utilities (Pub. Util.) Code § 913.2, 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 Investor-Owned Utilities (IOUs)[1], and the costs and benefits to ratepayers.[2] This report details the following:

- CPUC Smart Grid-related activities in 2015 (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 1.2.3.).

1.1 What is the Smart Grid?

The Smart Grid,[3] as described in the State of California by Senate Bill (SB) 17 (Padilla, 2009), is a fundamental change in the existing electricity infrastructure that utilizes advances in technology to create a better, safer, greener electricity supply. The objectives in California, per SB 17 and Pub. Util. Code § 8360 et al., are clear. They 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;

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

[3] Per the IEEE, 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 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 legislators on numerous fronts throughout 2015 to advance grid modernization. The resulting initiatives are oriented toward 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 a 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.[4] However, the accelerating adoption of customer-side intermittent renewable generation, primarily solar photovoltaic (PV), has produced new operational challenges for the grid and is driving the current need for IOU investment in Smart Grid technologies. Modernizing grid infrastructure, such that it serves as a platform rather than an impediment for customer adoption of distributed energy resources (DERs), [5] is becoming a

[4] 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).

[5] DERs are defined in PUB. UTIL. Code § 769 as renewable distributed generation, energy storage, demand response, energy efficiency, and electric vehicles.

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 (DRP) proceeding now underway will guide new Smart Grid investment requests in future GRCs to meet these challenges.[6] 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.

1.2.1 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 is still some divergence on how to reflect some environmental and customer benefits in monetary terms. The costs and benefits shown in Table 1 below reflect the reporting period for the IOUs' Smart Grid Update Reports, which cover fiscal year 2014-2015 (July 1, 2014 through June 30, 2015). Costs are calculated as a sum of all the Smart Grid programs 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.

Table 1 IOU Costs and Benefits for Fiscal Year July 1, 2014 through June 30, 2015

IOU	Smart Grid Costs ($Millions)	Smart Grid Benefits ($Millions)
PG&E	$831.00[7]	$ 19.60[8]
SDG&E	$115.30	$123.84
SCE	$ 91.00	$215.20[9]

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

[7] Of this total, $562.4 million represents the cumulative cost of three T&D automation programs incurred since the programs' inceptions.

[8] PG&E also reports non-monetized benefits of 40 million avoided customer outage minutes and 49.9 million pounds of avoided CO2 emissions as a result of installing Smart Grid technologies.

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

1.2.2 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.

The CPUC began implementing AB 66 (Muratsuchi, 2013) with a new rulemaking that opened in December 2014.[10] That rulemaking requires IOUs to report reliability date on a more local basis than historically reported. Although this activity is not directly Smart Grid-related, several of the new Smart Grid systems deployed by the utilities such as Geographic Information Systems (GIS) and Outage Management Systems are expected to produce more targeted, information-rich reliability reporting.

The CPUC focuses on reliability and safety. Reliability and safety are not the same, although they are related. Numerous mission-critical applications, such as health care, communications, refrigeration, and heating and cooling depend on reliable electric supply. Smart Grid technologies can improve reliability and provide greater confidence to the general public that their mission-critical applications are based on a dependable electric supply, thereby supporting the safety mission of the CPUC.

The CPUC also focuses on reliability and resiliency. Again, reliability and resiliency are not the same, although they are related. Reliability is well-defined with specific quantitative metrics (see Footnote 4), while 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 contributes to maintaining a more resilient grid that is consequently more resistant to failure.

In 2014, the Commission adopted a new approach to incorporating safety-risk assessments in the utilities' GRCs.[11] This new safety framework will provide information to utilities, interested parties, and the Commission. This information will help them to assess safety risks and to manage, mitigate, and minimize such risks. For the three large IOUs, the assessment will take place through two new procedures that will inform each utility's GRC application, in which the IOUs may request funding for safety-related investments. An example of such an investment is the implementation of Common Cybersecurity

[10] R.14-12-014, Reliability Rulemaking, opened December 18, 2014.

[11] Decision (D.)14-12-025 in R.13-11-006, incorporated quantitative risk analysis into the GRC process.

Services (CSS) by SCE. This investment implements various cybersecurity technologies developed by the Defense and Intelligence industries, and this CSS system enables greater protection against a cyber-attack on the grid and it also safeguards sensitive customer data.

1.2.3 What to Expect in 2016 at the CPUC

Below is a list of some of the Grid Modernization and Smart Grid development projects to watch for in 2016:

- A proposed decision (PD) in the Energy Storage Procurement Framework rulemaking (R.15-03-011) is expected in early 2016; it will address policy and program refinements to the Energy Storage Procurement Framework. The Commission will review the results of the IOUs' 2014 Energy Storage Request for Offers (RFO) Solicitation and the IOUs will initiate their 2016 Energy Storage RFO Solicitation.
- Four ongoing PG&E Smart Grid Pilot projects approved by the Commission in D.13-03-032 are required to be completed by the end of 2016. These projects will focus on:
    1. Line sensors;
    2. Voltage and reactive power optimization;
    3. Detecting and locating distribution line outages and faulted circuit conditions; and
    4. Short-term demand forecasting.
- A PD in the Electric Reliability Reporting Rulemaking (R.14-12-014) was issued in November 2015 proposing enhancements to IOU reliability data reporting that would take effect in July 2016;
- A PD in the Rule 21 Interconnection Proceeding (R.11-09-011) is expected in the first quarter of 2016, which will address cost certainty for interconnection upgrades and streamlining the interconnection process for behind the meter non-exporting energy storage;
- The Smart Inverter Working Group (SIWG), part of the Rule 21 Interconnection Proceeding, which will finalize recommendations for Commission adoption of communication protocols and advanced functionality for Smart Inverters, which will connect DERs to the grid and mitigate DER grid impacts;
- The first Demand Response Auction Mechanism deliverable will be submitted by the IOUs for Commission approval in the first half of 2016, as per D.14-12-024, and
- A PD in SDG&E's 2016 GRC is expected to be issued, covering a number of Smart Grid-related proposed investments for the next GRC cycle.

2. Commission Activities Related to Smart Grid in 2015

2.1 Deployment Plan Background

SB 17 (Padilla, 2009) established the state policy of Grid Modernization through implementation of the Smart Grid and required the IOUs to file Smart Grid Deployment Plans. The Commission subsequently adopted requirements for Smart Grid Deployment Plans through D.10-06-047, which specified that the Smart Grid Deployment Plans must include the following eight elements:

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

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.[12]

The CPUC's Smart Grid proceeding was closed in 2014 by D.14-12-004, which:

- 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;

[12] Each utility Smart Grid Annual report is available at: http://www.cpuc.ca.gov/PUC/energy/smartgrid.htm.

- 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.

2.2 Distribution Resources Plan

Pub. Util. Code § 769[13] required the IOUs to file Distribution Resource Plans (DRPs) by July1, 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 addition upgrades; 2) Locational Net Benefits Analysis (LNBA), which identifies the optimal locations for the deployment of DERs to maximize distribution and ratepayer benefits; and 3) DER Growth Scenarios, which forecast DER penetration under different market and policy assumptions which are the different scenarios of DER growth. The IOUs' analyses are intended to 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 goals of the DRP proceeding broadly encompass 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 IOUs planned the system for one-way power flows emanating from centralized generation, are undergoing dramatic changes as a result of the requirements of § 769. New grid developments enabled under the DRPs 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, greener grid.

The Commission instituted a quasi-legislative rulemaking in August 2014, to determine the structure of DRPs and to evaluate the IOUs' DRP filings that were submitted on July 1, 2015. The CPUC issued detailed guidance to IOUs on how to file DRPs in February 2015. Thus far in the proceeding, the Commission has conducted numerous workshops on various aspects of the plans. The workshops are aiming to establish frameworks for the three major analyses and to evaluate barriers to DER-centric system planning and DER deployment as enumerated in the DRP. The Commission's Energy Division prepared a draft proceeding road map as input into the proceeding's schedule and scope development

[13] Instituted by AB 327 (Perea, 2013).

process. As a next step, the Commission will release a Scoping Memo, likely in early 2016, that will specify the scope and schedule of the proceeding. Many more workshops, working group activities, and Commission activities such as Rulings and Decisions on various aspects of the DRPs, including approval of demonstration projects, are planned for 2016.

2.3 Integrated Distributed Energy Resources (IDER)

The IDER proceeding is closely linked to the DRP. The DRP proceeding is primarily concerned with distribution grid planning and identifying enhancements required for optimal placement and operation of DERs. The Integrated Distributed Energy Resources (IDER) proceeding (R.14-10-003) is focused on DER sourcing, *i.e.*, guiding optimal sets of resources to the appropriate locations on the grid. Both proceedings are directly concerned with meeting the policy objectives expressed in Pub. Util. Code § 769 and are being coordinated.

As California IOUs begin to plan and operate the distribution system around accommodating higher penetrations of DERs and two-way energy flows through the DRP effort, opportunities for integrating DERs will become more available for utilities and customers. These opportunities will require a regulatory framework that can remove barriers to entry and allow the formation of markets to drive adoption of integrated packages of DERs. The Commission is currently addressing the regulatory framework through an OIR to "Create a Consistent Regulatory Framework for Integration of Distributed Energy Resources" (IDER). [14] The adopted framework and goal for the IDER included:

- Framework: A regulatory framework that enables customers to effectively and efficiently choose from an array of DERs. This framework is based on the impact and interaction of such resources on the grid as a whole, on customer's energy usage, and on the environment;
- Goal: To deploy DERs that provides optimal customer and grid benefits, while enabling California to reach its climate objectives.

The remainder of the proceeding will support the development of an end-to-end framework for integrated DERs including relevant valuation methodologies and sourcing mechanisms.[15] As a first step, the Commission staff is facilitating a working group to develop recommendations to address inconsistencies in the cost-effectiveness framework for demand side resources. Proceeding activities will

[14] R.14-10-003 – Establishing a consistent regulatory framework for planning and evaluation of Integrated Demand Side Resource programs.

[15] Decision 15-09-022, Decision Adopting an Expanded Scope, a Definition, and a Goal for the Integration of Distributed Energy Resources, dated September 22, 2015.

occur in close coordination with the DRP proceeding, and the IDER will aim to develop incentives, tariffs and/or procurement programs to target customer adoption of DERs in the optimal locations identified in the DRP. Ultimately, the IDER will help California's grid modernization efforts by sourcing the networked DERs around which the Smart Grid of the future will be planned and operated.

2.4 Interconnection Reform and Smart Inverter Activities

In 2015, the CPUC oversaw significant progress in improving Rule 21, the CPUC jurisdictional tariff governing the application and study process for DER interconnection, as well as development of advanced inverter functionality. For the latter, the CPUC worked with the Smart Inverter Working Group.

In 2015, an active stakeholder process within the Interconnection Rulemaking (R.11-09-011)[16] focused on two primary goals: 1) enhancing the predictability and certainty of interconnection upgrade costs 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 the November 2015 filing of joint-party proposals that are now under Commission review with consideration of 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.

According to the joint party proponents, these pending proposals would work to enhance the DER interconnection process, which would make it easier for customers to interconnect those energy technologies that grid modernization efforts are intended to accommodate. Commission decision on these issues is expected the first quarter of 2016.

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

Smart Inverter Working Group

Smart Inverters enable communications and control of networked DERs and represent one of the foundational building blocks of the Smart Grid. The advanced inverter functionality standards that are being developed in the Smart Inverter Working Group (SIWG) will ultimately be incorporated into the design requirements in Rule 21.

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 Rule 21 mandate that all DERs must be capable of communications consistent with IEEE 2030.5,[17] default protocol used by IOUs to communicate between individual DERs, facility DER management systems, and DER aggregators. As of late 2015, the IOUs were in the final stages of implementing Phase 2 communication protocols, and minimal Rule 21 tariff revisions to reflect DER communication capability that will be forthcoming in the first quarter of 2016.

Since March 2015, the SIWG has been discussing development of a number of additional Phase 3 smart inverter functions. 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 SIWG anticipates that its Phase 3 recommendations will be submitted to the Commission in the first quarter of 2016.

2.5 Storage Roadmap Activities

The Commission's energy storage procurement policy was formulated to reduce peak-energy demand, contribute to reliability, defer transmission and distribution upgrade investments, integrate renewable energy, and reduce greenhouse gas emissions through the utilization of energy storage devices.[18] 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.[19]

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

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

[18] R.10-12-007, to implement provisions of AB 2514 (Skinner, 2010)

[19] D.13-10-040, D.14-10-045

storage developers, generators, environmental groups, and other industry stakeholders published "Advancing and Maximizing the Value of Energy Storage Technology-A California Roadmap".[20]

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 2014-2016 procurement cycle were filed in December 2015.

On April 2, 2015, the Commission opened an OIR[21] in response to the enactment of AB 2514 (Skinner, 2010) and 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 that were either short-term or that were not addressed. A PD on Phase I topics was issued in December 2015 that addresses outstanding policy issues on the implementation of the storage mandate prior to commencement of the IOUs' 2016 energy procurement solicitations. On December 1, 2015, SCE and PG&E filed, as required, applications for approval of the results of their 2014 storage RFOs. SDG&E will file their proposed storage contracts in March 2016, along with their All-Source RFO.

2.6 Plug-In Electric Vehicle Integration

Beginning with R.08-12-009, the Commission began exploring the potential for Plug in Electric Vehicles (PEVs) to interact with an increasingly modernized grid. The concept known as Vehicle-to-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.

In 2015, the Commission continued to develop policies and customer programs and to guide research on the technologies needed to ensure the efficient integration of and widespread deployment of plug-in hybrid and electric vehicles with the electricity system, as required by Pub. Util. Code § 740. The

[20] The Storage Roadmap is located at: http://www.cpuc.ca.gov/PUC/energy/Storage_Roadmap.htm.

[21] R.15-03-011

activities related to PEVs are broadly categorized into two areas:

1) Infrastructure deployment, and

2) Vehicle-grid integration (VGI).

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. Smart Grid-related activities are mainly tied to the VGI category.

The Commission's Energy Division oversees several ongoing R&D projects that are intended to inform the development of rules and technology that will be necessary to facilitate VGI. SB 350, signed by Governor Brown in October 2015, found specifically that PEVs should assist in grid management by integrating renewable energy generation and reducing fuel costs for vehicle drivers who charge in a manner consistent with electrical grid conditions.

In addition, Energy Division also oversees the administration of nearly two dozen PEV-related research projects that are funded by the Electric Program Investment Charge (EPIC). Specifically, the CEC's EPIC investments directed $10 Million to projects that evaluate how PEVs can communicate with the electric grid and, accordingly, optimize their charging profiles.

2.7 Demand Response Policy Advancements

The electric power industry considers demand response as an increasingly valuable resource option that has capabilities and potential impacts 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 is a valuable tool in meeting California's progressive renewable targets while maximizing grid efficiency and operation and improving integration and interoperability between various renewable sources and loads within the market.

In D.14-12-024, the Commission reinforced the intention to bifurcate demand-response programs that are currently under the purview of the utilities and to require integration of appropriately-designed programs into the CAISO wholesale energy market. The full bifurcation and market integration must occur on or before January 1, 2018. During the transition years, the Commission is piloting a capacity-procurement mechanism called the Demand Response Auction Mechanism (DRAM) for demand response provided by third parties outside of utility programs. The first deliveries under the DRAM are to start on June 1, 2016, and the IOUs are currently in the process of selecting bids. The first pilot was adopted and the second pilot is expected to be considered by the Commission in the first quarter of 2016. During the transition years, the IOUs are also bidding in portions of their own demand response portfolios into the CAISO market.

To enable a more robust and reliable Demand Response, the Commission has authorized Automated Demand Response Programs (Auto-DR), which provides incentives to customers who invest in controls and energy management technologies that enable automation of load reduction. During an automated demand response event, the utility or third-party Demand Response Provider sends a signal to the energy management system (EMS) on site. The EMS will then initiate the customer-selected pre-programmed demand response strategy. Auto-DR eliminates the need for manual activation of demand response strategies and more closely aligns the execution of demand response events with overall grid modernization efforts.

As a condition of receiving technology incentives, the customer is required to enroll and remain in a Demand Response program for at least three years. Participants receive 60 percent of the total program incentive after successful verification of equipment installation and subsequent testing of the committed DR strategy. The remaining 40 percent of the incentive is paid upon verification of participant performance in a full DR season.

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 making recommendations to interpret and implement requirements in Pub. Util. Code § 277.1. A PD in R.14-12-014 proposed directing the utilities to report reliability data on a district level and in some cases for a City. When approved, the PD will require sustained reliability deficiency in an area to be based on two to three years of consistently poor performances.[22] 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 may be combined in to a single report. All utilities may be required to include remediation plans to improve their worst-performing circuits and to explain the justification of these plans in their reports. They may be required to provide a customer hotline for reliability information and to offer customers the ability to order Electric Reliability Reports online.

The PD would also allow customers to request reliability information about their circuits via utility websites and to receive responses in a timely manner. However, utilities would not have to provide specific reporting to monitor service of essential customers. In this way, enhanced Reliability Reporting will help the state’s grid modernization efforts by increasing transparency into the reporting metrics for

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

reliability standards and would clarify the remediation efforts the IOUs are taking to target and address the worst performing circuits.

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

Customer Data Access (CDA) is a program that attempts to build cross-jurisdictional regulatory structures to provide an objective platform for collaboration between operations, customers, markets, and service providers. D.14-05-016 established rules around CDA, which was an extremely important milestone given the exponentially expanding volumes of data that are being produced as a result of Smart Grid infrastructure development.

In 2015, the IOUs commenced with the Energy Data Request and Release Process (DRRP) pursuant to D.14-05-016, which established a process for eligible parties to request customer energy usage data. D.14-05-016 also called for the formation of the Energy Data Access Committee (EDAC), which is a non-adjudicatory body established to receive and advise on data request issues that arise from the DRRP. The EDAC committee, which meets quarterly, has 15 seats to ensure representation from a wide range of data stakeholders, including a seat for each of the IOUs, the CPUC, ORA, CEC, Local Governments, Consumer Advocates, Academic Researchers, and rotational interested parties.

The DRRP Decision required that the IOUs establish web pages and email addresses for the public to efficiently access information and to request applications. On their respective web pages, the IOUs maintain a catalog of data requests, including those that were withdrawn or cancelled. The IOUs file quarterly advice letters identifying updates to these data request catalogs.

According to process guidelines, requesting parties must complete an application that discloses the details of their request, execute a standard Non-Disclosure Agreement, and allow for a four-week period in which the IOUs submit a notification of data transfer to the CPUC's Executive Director.

In 2015, the IOUs responded to numerous requests, primarily from state agencies like the CEC, academic researchers such as University of California Berkeley and University of California Los Angeles, and local governmental authorities where the requests sought energy data to assist mainly with climate action planning.

The details of requested data are varied, but according to guidelines laid out in D.14-05-016, all customer energy use data must be anonymized and aggregated at specified levels according to the needs of each market sector (residential, commercial, agricultural, industrial). Numerous procedural safeguards are in place to ensure customer privacy and to adhere to the best data privacy practices. One such safeguard is the standard Non-Disclosure Agreement that must be completed for non-governmental requests. For governmental requests, organizations must adhere to the terms and conditions set forth in

D.14-05-016 such that the requesting party will use the data for the stated purposes and not release the data to a third party or the public.

3 IOU Smart Grid Projects in California

3.1 Summary of IOU Activities in 2015

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, which are filed by the IOUs each October, per D.10-06-047, and are organized into the categories below:

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

The IOUs are also required to report the monetary value of benefits stemming from Smart Grid activities. The methodology for calculation of benefits is similar among the three IOUs. However, there are still some differences in methodology between PG&E, SDG&E and SCE. The costs and benefits shown below were accrued during the reporting period of the 2015 IOU annual update reports, which covers July 1, 2014, through June 30, 2015.

The IOUs reported that smart meter deployments continued to provide benefits during the reporting period. They also reported relevant reduction in operating expenses due to the elimination of a significant portion of meter reading activities and customer services field activities, and they report improved ability of customers to use various time-variant pricing rate programs which have provided significant peak-load reduction, especially when combined with enabling technology. The IOUs continue to invest in Smart Grid-related projects and initiatives with the objective of enhancing grid infrastructure to provide safe, reliable, and affordable energy services to its customers. This in turn enhances the IOUs' understanding of grid operations, the potential for deployment of new and innovative Smart Grid technologies, and customer expectations.

1.Customer Empowerment

According to the IOUs, Customer Empowerment efforts provide customers with information regarding their energy usage, program rates, energy conservation, and peak-load reductions. This information will enable customers to improve their use of time-variant rates. Projects that deliver the information, services, and control sought by customers and that enable demand response, dissemination of pricing information, and implementation of Home Area Networks (HAN) capabilities are included in this category. Various tools such as 'Universal Audit Tools' make it easier for customers to find targeted energy savings ideas for their homes or businesses. The IOUs provide progressive tools that continually leverage customer-provided information and include recommendations for energy efficiency, demand response, distributed generation, and behavioral changes.

As part of the customer empowerment process, the IOUs are in the process of continued implementation of the Energy Services Provider Interface (ESPI), which is a technology platform and infrastructure that enables receipt of customers' usage data. The IOUs are also in the process of continuing the PEV workplace charging pilot to gain a better understanding of consumer behavior related to fee-based charging and demand-response events, and the IOUs have initiated the test phase of an improvement program that will enable a scalable platform for customers to enroll in and receive digital maintenance and repair notifications.

2.Transmission and Distribution Automation/Utility Operations

Transmission Automation and Reliability (TAR) and Distribution Automation and Reliability (DAR) projects improve information and control capabilities for both the transmission and distribution systems. On the transmission side, TAR projects also enhance data collection and automation to prevent wide-scale blackouts. TAR also equips operators with the tools necessary to enhance bulk system reliability in coordination with the CAISO and neighboring utilities, and TAR pilots and deploys digital Smart Grid technologies. On the distribution side, DAR projects mitigates outages by developing self-healing circuit technology and automated outage responses, as well as fault location isolation and service restoration (FLISR) technology projects.

Utility operations projects involve asset management, safety, and operational efficiency. These technologies depend on reliable, high-speed communication transmission and distribution protection equipment that detect system events or conditions and automatically respond to them to stabilize the system.

3.Cyber and Physical Grid Security

As Smart Grid development becomes more widespread, vulnerability to attack, both cyber and physical, increases. The communications and control systems that are required to enable Smart Grid capabilities have the potential to increase the reliability risks of Smart Grid deployments if they are not properly secured. These security programs include a comprehensive set of capabilities such as common cybersecurity and the placement and execution of security controls throughout the network to facilitate resistance to attack and to manage risk.

4.Integrated and Cross-Cutting Systems

This category of project includes activities that cross multiple areas of utility operations and may involve several overlapping systems. An integrated approach for this project would seek an overall network that is efficient and a platform that would deliver a stream of benefits across IOU operations and on to customers. Integrated communications systems will provide solutions to enable sensors, metering, maintenance, and grid asset control networks. Over the longer term, integrated and cross-cutting systems would enable information exchange among IOUs, service partners, and customers using secure networks. Advanced technology and standards certification are required for the IOUs 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' workforces are prepared to make use of new technologies and tools and thus maximize the value of these technology investments.

5.Asset Management, Safety, and Operational Efficiency

Asset Management, Safety, and Operational Efficiency (AMSOE) enhances monitoring, operating, and optimization capabilities to achieve more efficient grid operations and improved asset management. These projects enable identification based on asset health, rather than purely on time-in-service measurements, and are designed to prevent critical equipment failure. AMSOE would help to avoid critical energy infrastructure failures and to manage costs associated with maintaining and replacing equipment.

Table 2 Advanced Metering Infrastructure (aka Smart Meters) Rollout

IOU (as of Oct. 2015)	Electric Opt-out (No. of customers)	Customer Complaints (escalated) [23]	Total Number of Electric Smart Meters (Millions)
PG&E	52,205[24]	7	5.48
SDG&E	2,752[25]	2	1.43
SCE	22,574	364	5.00

Source: IOU Smart Grid Annual Reports to CPUC, October 2015, and data provided by the IOUs

[23] 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.

[24] Gas Opt out – 36,102.

[25] Gas Opt out – 1,681.

3.2 San Diego Gas & Electric (SDG&E)

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 smart grid projects.

Costs

Table 3 SDG&E's Estimated Costs for Fiscal Year July 1, 2014 through June 30, 2015

Task	Value (Millions)
Customer Empowerment and Engagement	$ 30.90
Distribution Automation and Reliability	$ 24.20
Transmission Automation and Reliability	$ 5.70
Asset Management, Safety and Operational Efficiency	$ 10.93
Security	$ 2.67
Integrated and Cross-Cutting Systems	$ 40.90
Total Estimated Costs	$ 115.30

Benefits

Table 4 SDG&E's Estimated Benefits Realized for Fiscal Year July 1, 2014 through June 30, 2015

Benefit	Value (Millions)
Economic Benefits	$ 38.37
Reliability Benefits	$ 32.81
Environmental Benefits	$ 9.59
Societal Benefits	$ 43.08
Total Estimated Benefits	$ 123.84

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

- Initiation of continuous improvements to previously completed transformative foundation projects such as the Outage Management System/Distribution Management System/Advanced Distribution Management System/ Distributed Energy Resource Management System (OMS/DMS/ADMS/DERMS) to gain additional operational benefits;
- Demonstration at the existing Borrego Springs Microgrid of management with the newly installed microgrid resource manager software and use of a second substation energy-storage system;

- Evaluation of Unmanned Aircraft System (UAS) use cases as SDG&E became the first utility to receive Federal Aviation Administration approval to test Unmanned Aircraft Systems technology;
- Continuation of PEV growth to more than 17,000 total vehicles connecting to SDG&E's system;
- Evaluation of the Reduce Your Use Rewards program, which demonstrated that customers could achieve 25% load reduction with enabling technology and 7% without it; and
- Installation of an innovative new technology called Renewable Meter Adapter that purports to significantly reduce the residential rooftop solar installation cost for many customers without expensive and cumbersome breaker installations.

3.2.1 SDG&E Example Projects

This is a partial list from the SDG&E Smart Grid Status Update Report as of October 1, 2015.

- **Smart Meters[26] –** The SDG&E Smart Meter project deploys solid-state, digital devices that record energy usage data and, unlike traditional meters, transmit and receive data. Smart Meters record hourly electric consumption for residential customers and 15-minute consumption for commercial customers.
- **Centralized Calculation Engine[27] –** The Centralized Calculation Engine project incorporates multiple data sources and provides price and cost calculations across many operations and users in a centralized setting in order to ensure consistency of calculations and output across many operations and users. The engine will be flexible and will incorporate comprehensive rate, price, and cost modeling.
- **Smart Pricing Program[28] –** SDG&E's Smart Pricing Program, adopted in D.12-12-044, implements various dynamic rates along with information technology upgrades and outreach in order to enable customers to make informed decisions about their electricity consumption. D.12-12-044 also directs SDG&E to automate such business processes as rate analysis, meter data, enrollment and dis-enrollment, and to provide services to the customers via online tools for customers to view their energy usage and the cost of that usage. It also enables running rate comparisons between other applicable rates and selection of a capacity reservation charge.

[26] Annual Status Report of SDG&E for Smart Grid Deployments and Investments, October 2015, page 15.

[27] Ibid at 16.

[28] Ibid at 20.

- **Advanced Energy Storage**[29] – This project aims to install advanced energy storage devices that will mitigate the impact of intermittent renewables and provide SDG&E with experience developing, implementing, and operating new energy-storage technologies. The scope will include developing utility-scale (300 kW+) energy storage units at substations and other locations and distributed energy storage systems (DESS - typically 25 to 50 kW) on distribution feeders. DESS are also known as Community Energy Storage (CES) systems.
- **SDG&E Grid Communications Systems (SGCS)**[30] **–** The SGCS will implement advanced wireless communications systems to allow SDG&E to monitor, communicate with, and control transmission and distribution equipment, thus accelerating deployment of Smart Grid applications and devices. Within the scope of the SGCS project are efforts to monitor fault circuit indicators deployment; to standardize communication protocols at substations; to deploy a field broadband connections network to support implementation of phasor measurement units and to monitor distribution circuits; and to pilot a supervisory control and data acquisition (SCADA) optimization system to deploy IP wireless narrowband technology.

[29] Ibid at 25.

[30] Ibid at 44.

3.3 Southern California Edison (SCE)

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

Costs

Table 5 SCE's Estimated Costs for Fiscal Year July 1, 2014 through June 30, 2015

Task	Value (Millions)
Customer Empowerment and Engagement	$ 9.16
Distribution Automation and Reliability	$ 36.87
Transmission Automation and Reliability	$ 5.51
Asset Management, Safety and Operational Efficiency	$ 6.01
Security	$ 8.29
Integrated and Cross-Cutting Systems	$ 25.08
Total Estimated Costs	$ 91.00

Benefits

Table 6 SCE's Estimated Benefits Realized for Fiscal Year July 1, 2014 through June 30, 2015

Benefits	Value (Millions)
Operational Benefits	$ 6.60
Reliability Benefits[31]	$ 194.90
Demand Response/Conservation Benefits	$ 13.60
Total Benefits	$ 215.20

Highlights of SCE's Smart Grid deployment update include:

- Continued implementation of the Energy Service Provider Interface (ESPI), a technology platform to receive the customer's usage data;

31 Estimated using Value of Service Model developed in 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. This program inception started approximately two decades ago.

- Continued the PEV Workplace Charging Pilot to gain a better understanding of consumer behavior related to fee-based charging and demand response events, and to advise business customers regarding costs;
- Implementation of projects to improve information and control capabilities for distribution and transmission systems;
- Implementation of projects to improve the efficiency and security of grid operations; and
- Implementation of projects to support multiple Smart Grid domains for information sharing between the utility, service partners, and customers.

3.3.1 SCE Example Projects

This is a partial list from the SCE Smart Grid Status Update Report for October 1, 2015.

- **Energy Service Provider Interface (ESPI)**[32] – The ESPI platform supports customer authentication and authorization in data exchanges from SCE to a technically eligible third party. The ESPI platform also allows a customer to revoke data authorization and to provides a formal complaint process that customers may use in instances when a third party may be considered a bad actor.
- **Geographical Information System (GIS)**[33] – GIS is a comprehensive system that consolidates the physical, electrical, and spatial features of all Transmission and Distribution assets and allows end-users to access this information from a single reliable source. GIS will provide the ability to integrate multiple databases, both internal and external to Transmission and Distribution, and help meet safety, reliability, and compliance obligations. It will include detailed asset information, electrically linked information, and landbase information from such sources as the Bureau of Land Management and FEMA. This information will be used by business operations teams and SCE systems to improve operational effectiveness.
- **Circuit Automation**[34] – The primary purpose of SCE's Circuit Automation Program is to automatically restore power to customers after outages caused by faults.

[32] SCE Annual Update – Smart Grid, October 2015, page 11.

[33] Ibid at 18.

[34] Ibid at 20..

- **Distribution System Efficiency Enhancement Project (DSEEP)**[35] – The DSEEP consists of servicing and expanding the NETCOMM wireless communication system. The NETCOMM system provides radio communication infrastructure to remotely monitor and control SCE's distribution automation devices.
- **Grid2**[36] – This project is an initiative to build a single, scalable, secure, and cost-effective IP network to provide support for all current and future grid application using virtualization. This network is a type of service provider network that is capable of transporting and segmenting data for a variety of applications.

[35] Ibid at 27..

[36] Ibid at 27..

3.4 Pacific Gas & Electric (PG & E)

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

Costs

Table 7 PG&E's Estimated Costs for Fiscal Year July 1, 2014 through June 30, 2015

Task	Value (Millions)
Customer Empowerment and Engagement	$45.60
Distribution Automation and Reliability[37]	$173.70
Transmission Automation and Reliability[38]	$441.91
Asset Management, Safety and Operational Efficiency	$134.75
Security	$7.27
Integrated and Cross-Cutting Systems	$27.60
Total Estimated Costs	$831.00

Benefits[39]

Table 8 PG&E's Estimated Benefits Realized for Fiscal Year July 1, 2014 through June 30, 2015

Benefits	Value (Millions)
Direct Customer Savings	$0.7
Avoided Costs	$4.5
Avoided Environmental Costs	$0.2
Customer Energy Usage	$5.6
Customer Reliability Costs	$8.5
Total Cost Savings	$19.6
Avoided Outage Minutes	40.0 Million outage minutes
Greenhouse Gas Emissions	49.9 Million Pounds of CO_2 emissions.

[37] This figure entails $142.4 Million for the Distribution SCADA program incurred since program inception.

[38] This figure entails $108 Million for the Transmission SCADA program and $312 Million for the Modular Protection and Control Installation Program incurred since program inception.

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

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

- Smart Meter outage information improvement;
- Home Energy Reports project Energy Alerts;
- Automated Demand Response program;
- Fault Location and Service Restoration (FLISR) project; and
- Modular Protection and Automation Control (MPAC) project.

3.4.1 PG&E Example Projects:

- **Supply-side Demand Response (SSP) Pilot**[40] – The demand-response supply-side pilot will continue to explore the integration of demand response (DR) resources into the CAISO market to help with renewable resource integration that was started in the Intermittent Resource Management Program 2 (IRMP 2). If the pilot proves the program to be viable, the SSP will become the gateway for more DR resources to be integrated into the CAISO wholesale market. PG&E is structuring the SSP as a bridge between the retail and wholesale market and also to allow for third party DR providers' participation in the CAISO wholesale market. This step is vital in order to have a self-sustaining and fruitful third party DR market in California. The SSP may also assist PG&E in future grid planning and operations, especially as more connected intermittent generations appears on the grid, potentially improving overall system reliability.
- **Energy Diagnostics and Management (ED&M)**[41] – The ED&M is the implementation of a comprehensive strategy for customer self-service demand side management. The project is enhancing the online My Energy platform and launching new tools to help customers understand their energy bills, how they use and generate energy, rate options, and savings opportunities. In addition to launching new versions of existing online tools, the current Home Energy Report program is being scaled to 1.5 million residential customers, and a new Business Energy Report Emerging Technology project is being evaluated in a scaled field test. This project provides benefits to residential and to small and medium non-residential customers by providing actionable

[40] PG&E smart grid annual report – October 2015, page 14.

[41] PG&E smart grid annual report – October 2015, page 17.

information and personalized recommendations on how they can save energy, find the best rate for them, and explore distributed generation and electric vehicle options.

- **Time Varying Pricing Rates (TVP)**[42] – Time varying pricing products, such as Peak Day Pricing and Time-of-Use rates, take advantage of smart meter capabilities that enables charging customers different rates based on varying system conditions, which is intended to more closely align retail and wholesale electric prices for generation, as well as to create economic incentives for customers to actively manage their energy costs by shifting electricity use from higher-cost to lower-cost times. PDP provides between 30-45 MW of load reduction on the hottest days of summer, equaling the load of almost 2 peaker power plants. The SmartMeter™ has enabled PG&E to cost-effectively offer all customers these types of rate programs which provide significant customer and societal benefits.
- **Distribution Substation Control and Data Acquisition (SCADA)**[43] – The Distribution SCADA program focuses on increasing SCADA system deployment to support future Distribution Control Center consolidation and to improve reliability for customers. PG&E's goal is to achieve 100 percent visibility and control of all critical distribution substation breakers by 2019, adding or replacing SCADA for approximately 393 substations and approximately 1,107 breakers.
- **Smart Grid Fault Location, Isolation, and Service Restoration (FLISR)**[44] – This project continues the installation of FLISR systems to approximately 100 circuits per year across the system to improve customer service reliability. When installed, FLISR can reduce the impact of outages by quickly opening and closing automated switches to reduce what may have been a one-to-two-hour outage to less than five minutes. FLISR projects improves customer service reliability and provides real time load and voltage data, which supports distribution operations and DER/distribution resource integration.
- **Transmission Substation SCADA program**[45] – Under the Transmission Substation SCADA program, PG&E is in the process of installing new SCADA on the transmission system to provide PG&E's Electric Operations and the CAISO with full visibility into the transmission system, significantly improving efficiency and operational flexibility. PG&E's current goal is to achieve

[42] PG&E smart grid annual report – October 2015, page 21.

[43] PG&E smart grid annual report – October 2015, page 24.

[44] PG&E smart grid annual report – October 2015, page 26.

[45] PG&E smart grid annual report – October 2015, page 30.

100 percent visibility and to control of all transmission substations by 2019, adding or replacing SCADA for approximately 230 substations and approximately 673 breakers. Using SCADA is expected to reduce outage time, personnel travel, and operations time by providing better information for managing the system and also providing data to improve operation of and planning for the transmission system.

- **Modular Protection Automation and Control Installation Program (MPAC)**[46] –This multi-year program deploys pre-engineered, fabricated, and standardized control buildings in transmission substations. This program will help improve the reliability of the transmission system by replacing aging infrastructure and modernizing facilities.
- **Electric Distribution Geographic Information System and Asset Management (ED/GIS/AM) Project**[47] – The ED/GIS/AM project is a continuation of an enhanced approach to the automated mapping and facilities management project. While the purpose and scope of the ED/GIS/AM project is consistent with and leverages work completed as part of the predecessor project, key enhancement are being made to drive increased business value with the integrated GIS and enterprise asset management systems.

4 Conclusion

The Smart Grid policies pursued by the State of California and implemented by the state's IOUs are continuing to generate benefits for California ratepayers. The programs and projects have realized around $360 million in benefits in Fiscal Year 2014-2015 alone[48] and expenditures have been as originally budgeted. However, there is more work to be done to realize the vision of a modern and intelligent grid. Efforts related to electric vehicles, demand response, storage, Integrated Distributed Energy Resources, Distribution Resource Plans, Rule 21 Interconnection, and development of smart inverter functionality will help move California towards a low carbon grid of the future. California's rich tradition of entrepreneurship, technological innovation, and forward-looking regulation continue to enable California to lead the nation in Smart Grid development.

[46] PG&E smart grid annual report – October 2015, page 30.

[47] PG&E smart grid annual report – October 2015, page 33.

[48] See Table 1.

CPUC Smart Grid Vision

"The CPUC continues to advance the vision first established in the Smart Grid proceeding. California's bold energy and climate goals will dramatically affect our electric grid. With the passage of Senate Bill 350, we expect to reach very high levels of renewable-sourced electricity and demand resources in our grid by 2030. This level of largely intermittent energy, along with increasing use of electric vehicles and the incorporation energy storage and other new distributed energy technologies, makes the need for an intelligent, modern grid imperative. We are proud that California and the CPUC continue to lead the nation in Smart Grid innovation and the deployment of distributed energy resources."

- Michael Picker, President, California Public Utilities Commission, December 2015.