American Recovery and
Reinvestment Act of 2009

2015 Progress Report for OE ARRA Smart Grid Demonstration Program

Aggregation of RDSI, SGDP, and SGIG Results

Renewable and the Distributed Systems Integration Program
Smart Grid Demonstration Program
Smart Grid Investment Grants

May 2015

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List of Acronyms

2HTS	Second-generation, high-temperature, superconducting
AC	Alternating current
AES	Advanced energy storages
AGC	Automatic generation control
AMI	Advanced metering infrastructure
AMR	Automated meter reading
ARRA	American Recovery and Reinvestment Act of 2009
ATK	ATK Launch Systems
B2G	Building to grid
BCR	Benefit-to-cost ratio
BESS	Battery energy storage system
BMS	Building management system
BWP	Burbank Water and Gas
CAES	Compressed air energy storage
CB	Customer behavior
CBM	Consumer-based microgrid
CCET	Center for the Commercialization of Electric Technologies
CEHE	CenterPoint Energy Houston Electric
CERTS	Consortium for Electrical Reliability Technology Solutions
CES	Community energy storage
CHP	Combined heat and power
CI	Customers interrupted
CIS	Customer information system
CMI	Customer-minutes interrupted
CPP	Critical peak pricing
CVR	Conservation voltage reduction
DA	Distribution automation
DACR	Distribution automation circuit reconfiguration
DAT	Data Analysis Team
DC	Direct current
DER	Distributed energy resources
DERMS	Distributed energy resource management system
DG	Diesel generator
DLR	Dynamic line rating
DMS	Distribution management system
DOE	U.S. Department of Energy
DR	Demand response
DRCC	Demand Response Control Center
EE	Energy efficiency
EISA	Energy Independence and Security Act of 2007
EPB	Electric Power Board Chattanooga
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ESCT	Energy Storage Computational Tool
ESS	Energy storage system
EV	Electric vehicle
FCL	Fault current limiting
FLISR	Fault Location, Isolation, and Service Restoration
FPL	Florida Power and Light
FRRS	Fast response regulation service
FTR	Final Technical Report
GWAC	GridWise Architecture Council
HAN	Home area network
HEMP	Home Energy Management Platform
HVAC	Heating, ventilation, and air conditioning
IADR	Intelligent agent DR
IBCU	Incremental building control unit
ICAES	Isothermal compressed air energy storage
IEEE	Institute of Electrical and Electronics Engineers
IHD	In-home display
IIT	Illinois Institute of Technology
IOU	Investor-owned utilities
IP	Internet provider
IPC	Idaho Power Company
IPL	Indianapolis Power & Light Company
ISGD	Irvine Smart Grid Demonstration
ISM	Integrated System Model
ISO	Independent System Operator
IVVC	Integrated Volt Var Control
KCP&L	Kansas City Power & Light
KW	Kilowatt
KWh	Kilowatt-hour
LADWP	Los Angeles Department of Water and Power
LC	Load control
LCOE	Levelized cost of energy
LiFePO4	Lithium Iron Phosphate
LIPA	Long Island Power Authority
MBRP	Metric and Benefits Reporting Plan
MBT	Metrics and Benefits Team
MDMS	Meter data management system
MECO	Maui Electric Company
METIR	Metrics and Information Repository
MGE	Madison Gas and Electric
MID	Modesto Irrigation District
MMC	Microgrid master controller
MO	Microgrid operator

MVA	Megavolt-ampere
MW	Megawatt
MWh	Megawatt-hour
NERC	North American Electric Reliability Corporation
NETL	National Energy Technology Laboratory
NPV	Net present value
NRECA	National Rural Electric Cooperative Association
NUSCO	Northeast Utilities Service Company
NYISO	New York Independent System Operator
NYPA	New York Power Authority
NYSEG	New York State Electric & Gas
O&M	Operation and maintenance
OE	Office of Electricity Delivery and Energy Reliability
OMS	Outage management system
PbA	Lead-acid
PCS	Power conversion system
PESS	Premise energy storage system
PG&E	Pacific Gas and Electric
PHEV	Plug-in hybrid electric vehicle
PJM	Pennsylvania Jersey Maryland
PLC	Power line carrier
PMU	Phasor measurement unit
PNM	Public Service Co of New Mexico
POTS	Plain old telephone service
PQ	Power Quality
PTR	Peak time rebate
PV	Photovoltaic
RDSI	Renewable and Distributed Systems Integration Program
RTO	Regional Transmission Organization
RTU	Remote terminal unit
SA	Substation automation
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory control and data acquisition
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SGCT	Smart Grid Computational Tool
SGDP	Smart Grid Demonstration Program
SGIG	Smart Grid Investment Grant
SMUD	Sacramento Municipal Electric Utility District
SPP	Southwest Power Pool
SRJ	Santa Rita Jail
TE	Transactive energy
TOU	Time of use
TPO	Technical Project Officer
TR	Topical report
TSP	Thermal storage plant
U.S.	United States
UCLA	University of California-Los Angeles
UDM	Utility distribution microgrid
UL	Underwriters Laboratories
UNLV	University of Nevada, Las Vegas
USC	University of Southern California
VirG	Virtual generator
VPN	Virtual private network
VRFB	Vanadium redox flow battery
VVO	Volt/VAr optimization
WVSC	West Virginia Super Circuit
ZNE	Zero net energy

Executive Summary

This report provides an analysis of the business case for the smart grid based on an aggregation of the analyses of the Department of Energy (DOE) Smart Grid demonstration programs. The various Smart Grid programs associated with this task were implemented through separate initiatives and described in separate reports.

This report summarizes the analyses performed and reported under the ARRA Smart Grid Business Case Analysis and Cost Metrics and Benefits Analysis of the Smart Grid Demonstration Program and incorporates their details by reference. This report provides:

- a summary of the overall results of the analysis
- a basis for the business case supporting smart grid implementation (primarily through incorporation of other reports produced under this task by reference)
- cross-functional observations that may not otherwise be apparent at the program level

The primary smart grid programs analyzed are the Renewable and Distributed Systems Integration Program (RDSI) and the Smart Grid Demonstration Program (SGDP).

A number of supporting programs were also implemented to provide the necessary foundational support for the RDSI and SGDP initiatives. These foundational programs are also described in this report.

1. Introduction

This report describes the analyses of various Department of Energy (DOE)-funded smart grid programs. The following three DOE-funded smart grid programs form the data basis of this analytical work.

- Renewable and Distributed Systems Integration Program (RDSI)
- Smart Grid Demonstration Program (SGDP)
- Smart Grid Investment Grant Program (SGIG)

These three programs with DOE funding of over $4 billion created a stimulus for advancing smart grid investment in the United States (U.S.).

The RDSI program is the smallest of the three programs and consists of nine projects that were awarded in 2008. The two larger initiatives are the SGDP, consisting of 32 projects and the SGIG program, consisting of 99 projects. The SGDP and SGIG programs were originally authorized by the Energy Independence and Security Act of 2007 (EISA) and later modified by the American Recovery and Reinvestment Act of 2009 (ARRA). DOE's Office of Electricity Delivery and Energy Reliability (OE) is responsible for managing these five-year programs. Complete details on these programs may be found at www.smartgrid.gov.

All three programs are still in progress as of May 2015, but many of the SGDP and RDSI projects have been completed. This report analyzes the currently available data from these programs and summarizes the various reports which document the more detailed analysis. The information coming from, and therefore the analysis of, the incomplete SGIG, SGDP, and RDSI projects limits the completeness of the associated analyses and reports. These limitations are identified in the corresponding reports. The three programs providing the foundation of analyses are introduced below.

1.1 Renewable and Distributed Systems Integration Program

The aim of the RDSI program was to develop and demonstrate new distribution system configurations integrated with distributed resources. The projects are specifically focused on demonstrating microgrids or their enabling elements, such as communications and control strategies for demand response, distributed renewable generation systems, storage technologies, advanced sensors, and energy efficient building sub-systems. The microgrids being demonstrated are capable of operating in both grid parallel and islanded modes.

The nine RDSI projects, awarded in fiscal year 2008, involve a mix of distributed energy resources (DER) and related innovative technologies. These projects have an aggregated capacity of greater than 15% of the capacity of the associated distribution substation, single distribution feeder, or multiple distribution feeders. Further, such aggregations of distributed resources seek to achieve a reduction of at least 15% of the power that would otherwise be normally supplied by the distribution substation or distribution feeders during peak load periods.

Structured as cooperative agreements, the RDSI projects were selected through a merit-based solicitation in which the U.S. DOE provided financial assistance with matching cost share from the recipients. Including recipient cost share, the combined budget of the nine projects exceeds $100 million. Six of these RDSI projects received incremental SGDP funding through the ARRA in addition to their original RDSI funding to fully fund the projects. The ATK Launch Systems (ATK), Chevron, and Mon Power projects did not receive any incremental SGDP funds. (1) As of May 2015, the actual expenditure was $94 million with the federal share totaling $51 million for the nine projects.

1.2 Smart Grid Demonstration Program

The SGDP was authorized by the EISA, Section 1304, as amended by the Recovery Act, to demonstrate how a suite of existing and emerging smart grid concepts can be innovatively applied and integrated to prove technical, operational, and business-model feasibility. The aim was to demonstrate new and more cost-effective smart grid technologies, tools, techniques, and system configurations that significantly improve on the ones commonly used today. The results of the demonstrations were also expected to provide information that could improve future decision making regarding all phases of smart grid investments including design, procurement, installation, operation, and performance evaluation.

SGDP projects were selected through a merit-based solicitation in which the U.S. DOE provided financial assistance of up to 50% of the project's cost. Note that SGDP projects are cooperative agreements, whereas the Smart Grid Investment Grant projects are grants. Additional information about the original Funding Opportunity Announcement can be found at https://www.fedconnect.net/FedConnect/?doc=DE-FOA-0000036&agency=DOE.

Two types of smart grid projects were selected for the SGDP. One involves regional smart grid demonstrations to verify smart grid viability, quantify smart grid costs and benefits, and validate new smart grid business models at scales that can be readily replicated across the country. The second addresses energy storage technologies such as batteries, flywheels, and compressed air energy storage systems for load shifting, ramping control, frequency regulation services, distributed applications, and the grid integration of renewable resources such as wind and solar power.

The program consists of 32 projects in these two areas— Smart Grid Regional Demonstrations (16 projects) and Energy Storage Demonstrations (16 projects). The total budget for the 32 projects is about $1.6 billion; the federal share is about $600 million. (1) As of May 2015, the actual expenditure was $1.517 billion with the federal share totaling $586 million for the 32 SGDP projects. As mentioned previously, some of these funds were allocated to the RDSI program.

Figure 1 Smart Grid Demonstration Projects

Smart Grid Regional Demonstrations

Smart Grid Regional Demonstration projects are focused on advanced technologies for use in power system sensing, communications, analysis, and power flow controls. These projects assess the integration of advanced technologies with existing power systems including those that involve renewable and distributed energy systems and demand response programs. The technical and economic performance of these technologies are being evaluated for use in microgrids, automated distribution systems, advanced metering infrastructure, and plug-in hybrid electric vehicles (PHEV). (1)

Energy Storage Demonstrations

Energy Storage Demonstrations are focused on grid-scale applications of energy storage involving a variety of technologies including advanced batteries, flywheels, and underground compressed air energy storage systems. These projects are demonstrating a variety of size ranges and system configurations and their impacts on the electric transmission and distribution grid. Some are expected to be grid-connected demonstrations and some will focus on the development of storage technologies at the laboratory level. The technical and economic performance of these technologies is being evaluated for a variety of applications including load shifting, ramping control, frequency regulation services, voltage smoothing, distributed energy, and the grid integration of renewable resources such as wind and solar power. (1)

1.3 Smart Grid Investment Grant Program

The SGIG program was also authorized by the EISA, Section 1306, as amended by the Recovery Act. The purpose of the grant program is to accelerate the modernization of the nation's electric transmission and distribution systems and promote investments in smart grid technologies, tools, and techniques that increase flexibility, functionality, interoperability, cybersecurity, situational awareness, and operational efficiency and are affordable, reliable, clean, and flexible.

The SGIG projects were selected through a merit-based, competitive solicitation by which successful projects were eligible to receive federal financial assistance for up to 50% of eligible costs. Additional details about the original Funding Opportunity Announcement are available in the SGIG Funding Opportunity Announcement which may be found at http://www.cooley.com/files/announce_cleantech/20090706_FOA-SmartGridInvestGrants.pdf.

There are 99 SGIG projects with a total budget of about $8 billion. The federal share is about $3.4 billion. (1)

1.4 Overall Status of Smart Grid Programs

Some of the projects within these programs were incomplete at the time of this report. Analysis of the incomplete projects was based on the information available. Progress of these projects can be monitored by visiting Recovery Act Smart Grid Programs at www.smartgrid.gov.

2. Foundational Work

Substantial work was done by DOE's Modern Grid Initiative to develop the concepts of the smart grid and to identify its potential benefits. Another report, developed by the Electric Power Research Institute (EPRI) in collaboration with DOE provided a methodology for estimating the cost and benefits for smart grid concepts (described in 2.1 below).

2.1 Cost Benefit Methodology

A standard methodology for estimating the benefits and costs for smart grid programs was needed to ensure that results were reported on a consistent basis. DOE and EPRI led the development of a report entitled, "Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects" to meet this need. (2)

The report presents a comprehensive framework for estimating the benefits and costs of smart grid projects and a step-by-step approach for making these estimates. The framework identifies the basic categories of benefits, the beneficiaries of these benefits, and the smart grid functionalities that lead to different benefits. It then proposes ways to estimate these benefits, including their monetization. The report covers cost-effectiveness evaluation, uncertainty, and issues in estimating baseline conditions against which a project would be compared. The report also suggests metrics suitable for describing principal characteristics of a modern smart grid to which a project can contribute.

The report identified four fundamental categories of benefits:

- Economic – reduced costs, or increased production at the same cost, that result from improved utility system efficiency and asset utilization
- Reliability and Power Quality – reduced interruptions and power quality (PQ) events
- Environmental – reduced impacts of climate change and effects on human health and ecosystems due to pollution
- Security and Safety – improved energy security (i.e., reduced oil dependence); increased cyber security; and reduced injuries, loss of life, and property damage

Several types of benefits exist within each of these broad categories.

A number of foundational tools and processes were created to support the development, implementation, and analysis of the RDSI, SGDP, and SGIG programs. These foundational tools and processes are summarized below.

2.2 Metrics and Benefits Reporting Plan and Process

Building upon this earlier work, the Metrics and Benefits Reporting Plan and Process (MBRP) Guidebook was updated by modifying the earlier MBRP Guidebook for SGIG projects that was issued December 7, 2009. The update tailored the process to both SGDP and RDSI projects. This updated guidebook defined the process and framework for obtaining data in an organized fashion such that it could be consistently analyzed. It also described the type of information to be collected from each of the projects and how it would be used by DOE to communicate overall conclusions to the public.

Each of the projects worked through the MBRP, then reported to their respective Technical Project Officer (TPO) and Data Analysis Team[1] (DAT). As shown in Figure 2, the process involves three basic steps: gather information from the projects; analyze the information; and communicate the results to the public.

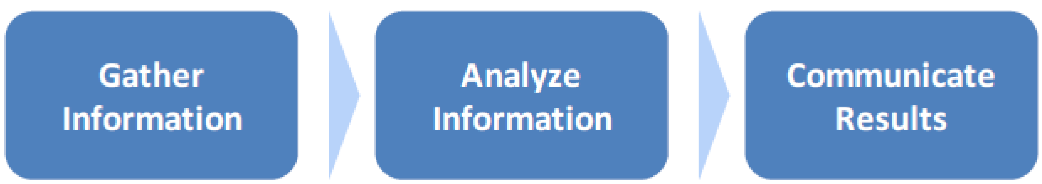

Figure 2 MBRP Approach

Gather Information

Projects were expected to gather information and report it to their Technical Project Officer (TPO) using "Build Metric" to track project costs and "Impact Metrics" to track project performance. Projects were also required to provide baseline metrics. Baseline values reflect the parameter values of the project's smart grid or energy storage initiatives without the SGDP or RDSI project, analogous to "business as usual" in a business case analysis. Baseline data can include historical performance data on the circuit(s) or data collected on the circuit(s) during the project prior to the operation of the smart grid or storage systems.

Table 1 summarizes the types of information collected.

[1] The Data Analysis Team includes NETL's Integrated Electric Power Systems Division, its support contractors, and Sandia National Laboratory (for the energy storage demonstrations).

Information Type	Description	Reporting Interval
Build Metrics	Build metrics refer to the monetary investments, electricity infrastructure assets, policies and programs, marketplace innovation and jobs that are part of smart grid projects.	Quarterly
Impact Metrics	Impact metrics refer to smart grid capabilities enabled by projects and the measurable impacts of smart grid projects that deliver value.	Semi-Annually

Table 1 Types of Information Collected

Analyze Information

Projects documented their results through Final Technical Reports (FTR). Once finalized, the FTRs were posted at www.smartgrid.gov.

The DAT used the data collected from projects to track investments, monitor and measure transformation, and report the results of the smart grid demonstrations. The DAT also analyzed the individual project data and a combination of data from all the projects to build a foundation of reliable facts and insights for the public. The information was grouped by project type allowing the results to be examined on a programmatic basis.

Communicate Results

Results were reviewed for each of the RDSI and SGDP projects that were complete and had submitted its FTR.

The DAT also compiled program level data and provided salient meta-analyses on common technological topics that were documented in Topical Reports. Topical Reports are discussed later in section 5.0.

2.3 Smart Grid Computational Tool

The Smart Grid Computational Tool (SGCT) is a Microsoft® Excel® spreadsheet-based application. It was developed to provide a consistent method for identifying and quantifying smart grid project benefits and was an outcome of a DOE-EPRI collaboration on smart grid metrics. It employs the benefit analysis methodology that DOE uses to evaluate the Recovery Act smart grid projects. (3) The SGCT performs the following functions:

- Characterizes smart grid projects by identifying the technologies that will be installed and identifying the technologies' functions.
- Based on this characterization, identifies the economic, reliability, environmental and security benefits the smart grid project will yield.
- Guides the user in entering data required for calculating the monetary value of smart grid benefits.
- Generates graphs and tables that summarize the costs and benefits of the project to help illustrate the project's overall value.

A user guide was also prepared to assist new users through the SGCT process. (4) The user guide assisted new users by:

- Providing context for the tool and explaining its purpose.
- Explaining the general architecture of the SGCT.
- Explaining the general methodology for assessing the benefits of a smart grid project.
- Explaining the asset-function-benefit mapping and defining each asset, function, and benefit.
- Providing a step-by-step instruction manual for using the SGCT.
- Providing the key concepts and assumptions.

2.4 Energy Storage Computational Tool

The Energy Storage Computational Tool (ESCT) is a Microsoft® Excel® spreadsheet-based application that was developed to provide a consistent method for identifying, quantifying, and monetizing the benefits of grid-connected energy storage projects. It calculates the net present value over the system's lifetime. (5) (6) The ESCT performs the following functions:

- Characterizes energy storage projects by identifying the storage technologies employed and identifying the applications pursued.
- Based on this characterization, identifies the economic, reliability, and environmental benefits the storage project will yield.
- Guides the user in entering data required for calculating the monetary value of benefits and associated capital and operation and maintenance (O&M) costs.
- Generates graphs and tables that summarize the costs and benefits of the project to help illustrate the project's overall value.

A user guide was also prepared to assist new users through the ESCT process. (7)

The foundational work and associated philosophy presented above were needed to frame, analyze, and effectively communicate the results of the DOE-funded smart grid programs discussed below.

3. Renewable and Systems Integration Program

3.1 RDSI Project Status

The RDSI program includes nine projects. Monongahela Power, ATK Launch Systems, and Chevron Energy Solutions did not receive ARRA funding. The status of each project is presented in Table 2 below.

Project	FTR Received[2]	FTR Projected
Monongahela Power	5/30/14[3]	
ATK Launch Systems	1/20/15	
Chevron Energy Solutions	7/7/14	
City of Fort Collins	NR	June 2015
Consolidated Edison Co of NY	2/25/15	
Illinois Institute of Technology	1/20/15	
San Diego Gas and Electric	1/21/14	
Hawaii Natural Energy Institute	12/31/14	
University of Nevada	NR	Sept 2015

Table 2 Status of RDSI Projects

3.2 RDSI Project Results

As of the date of this report, seven of the nine RDSI projects have completed their field demonstrations and FTRs have been received. The FTRs for these completed projects may be found at www.smartgrid.gov.

3.2.1 Completed RDSI Projects

Monongahela Power — West Virginia Super Circuit (8)

The West Virginia Super Circuit (WVSC) was led by Monongahela Power (Mon Power), a unit of FirstEnergy Corporation. Mon Power intended to demonstrate improved distribution system performance, reliability, and security of electric supply in the Morgantown, West Virginia, area

[2] Designates projects for which a final, approved FTR has been received. "NR" indicates that the FTR has not yet been received.

[3] Project was terminated before completion.

through the integration of DER and advanced technologies. The WVSC project was to consist of the deployment and/or integration of the following:

- Microgrid
- Fault Location Isolation Restoration System
- Fault Location Algorithm and Fault Prediction Algorithm
- DER dispatch for peak reduction

Given that the microgrid's total capital cost was estimated to be $1,011,146, Mon Power determined that the microgrid is not economically feasible in either grid-connected mode or islanded mode, from any beneficiary's perspective. The WVSC project was terminated in September 2013.

ATK Launch Systems — Integrated, Automated Distributed Generation Technologies Demonstration (9)

ATK conducted a demonstration of DER technologies. As originally planned, the project technology would have included a variety of DER—100 kilowatts (kW) of wind generation, 500 kW of flywheel energy storage capacity, and a 134 kW waste heat recovery system.

A number of setbacks caused ATK to revise the project plan and demonstrate different technologies than were originally planned. Due to contractual difficulties, ATK terminated its contract to procure a refurbished wind turbine and a flywheel array. A lead-acid battery energy storage system (BESS) was procured in place of the flywheel solution. Finally, during the integration phase, ATK discovered that the planned 134 kW waste heat recovery system as designed, would consume more power than it could produce. The equipment could not be modified to suit the project's needs without incurring significant costs, so ATK dropped the waste heat recovery system from the demonstration.

The actual demonstration included 95 kW of wind generation and 300 kW of lead-acid battery storage. ATK also developed an intelligent, system-wide automation system to monitor and control the DER technologies using Allen Bradley programmable logic controllers on an Ethernet network.

The wind turbine and battery storage system successfully operated in a complementary fashion. Output from the wind turbine charged the battery during the evenings, when the facility's loads began to decrease. During the daytime, when loads were higher, the battery discharged energy that had been stored the night before. The battery discharge rate, as well as the time of day that discharge occurred, could be controlled. A peak load reduction of 1.7% was achieved at the facility level.

Additionally, ATK directed exhaust flue gas from two boilers through a waste recovery generator to spin a turbine generator. When fully loaded, the rated output of this generator was 134 kW, which fed directly onto the plant power system for consumption.

No financial information was provided for benefits or costs.

Chevron Energy Solutions — Consortium for Electrical Reliability Technology Solutions (CERTS) Microgrid Demonstration with Large-Scale Energy Storage and Renewables at Santa Rita Jail (10)

Chevron Energy Solutions developed a consumer-based microgrid (CBM) at the Santa Rita Jail (SRJ) with a resource portfolio that totals approximately 6.6 megawatts (MW) of capacity. The portfolio is diverse and includes diesel generators (DG) (2.4 MW), a fuel cell (1 MW), photovoltaic (PV) (1.2 MW), storage (2 MW) and wind (11.5 kW). The advanced energy storage (AES) system includes a 4 megawatt-hour (MWh) Lithium Iron Phosphate ($LiFePO4$) battery. A 900 kVAr capacitor is also part of the portfolio. The facility's peak load each month is about 2 MW.

The SRJ microgrid was able to effectively integrate its DER with the AES. All of the protective functions required by the utility were successfully demonstrated and SRJ was seamlessly islanded and resynchronized with it. Parallel operation of the AES and DGs with their modified controls in island mode was also tested and power sharing (real and reactive) was successfully demonstrated. The ability to monitor DERs and dispatch the AES was proved in commissioning and in daily operation. Peak load reductions of 95% at the facility level and 15% at the feeder level were demonstrated.

SRJ operates as a full-time microgrid. At the supervisory level of control, the distributed energy resource management system (DERMS) enables the energy storage system to optimize on-site generation through transactive control to decrease the total cost of energy purchased from the utility. The current utility tariff schedule has time-of-use rates under which energy consumption and maximum power demand vary based on time of day and season. The AES stores energy purchased during less-expensive off-peak periods to be utilized during peak periods. In island mode using droop control[4], the local controllers keep the system stable. Demand and energy cost savings were estimated to be $110K per year.

This project demonstrated the potential for large commercialization of CERTS microgrid designs to future target customers with a demand for reliable power.

Consolidated Edison Company of NY — Interoperability of DR Resources Demonstration in NY (11)

Consolidated Edison Company of New York (Con Edison) demonstrated methods to enhance the integration of demand response (DR) resources into the distribution system. Con Edison's project, which was located in the control area of the New York Independent System Operator (NYISO), demonstrated the software, protocols, and communications infrastructure required to enable DER to improve load control, increase distribution system efficiency and reliability, and optimize these resources in the distribution network. Con Edison demonstrated interoperability by integrating the operation of a variety of conventional and renewable DR resources into the existing distribution network.

Con Edison created a DR architecture using the DR Control Center (DRCC) as the central coordinating element. DRCC resources include those with rapid response and the ability to maintain load reductions for multiple hours, when needed, such as buildings with DGs, facilities with energy storage, curtailable loads, and large multi-site resources, all of which can increase customer generation and/or decrease customer load.

Con Edison also demonstrated an incremental building control unit (IBCU) which is a set of hardware and programmed strategies that can control facility loads in response to market signals. It also installed a thermal storage plant (TSP) to demonstrate how this technology could be used to supply valuable ancillary services to the grid while also optimizing energy efficiency at the facility. The DRCC can also create a virtual generator (VirG) through the activation of customer DR and DER (i.e., load and generation) resources. The DRCC, TSP, and VirG all demonstrated positive economic benefits.

In total, Con Edison aggregated 23 facilities and 20 MW of generation into the DRCC. The project ultimately demonstrated successful integration of customer-sited DR resources into electric delivery company operation. The economics reported suggest that this project may

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[4] Droop control is an electrical generation term referring to the use of net frequency deviations from a setpoint as a signal to generator controls to adjust the speed of the generator to correct frequency deviations.

have a positive business case as the revenues received from NYISO for the various DR programs are greater than the costs for paying the customers to participate.

Illinois Institute of Technology — The Perfect Power Prototype for the Illinois Institute of Technology (12)

The Illinois Institute of Technology (IIT) microgrid is a CBM located 2.5 miles south of downtown Chicago and is bounded by major streets, highways, and railroads. It has a peak load of 12 MW, can be operated in grid-connected and island modes, and is capable of integrating new sustainable energy resources. The total generation capacity is 12,342 kW, including 8,000 kW of natural gas turbines, 300 kW of solar generation, 8 kW of wind generation, and 4,034 kW of backup generation. The IIT microgrid also includes a 500 kilowatt-hour (kWh), 250 kW flow battery and several smaller size storage devices.

The microgrid operates as a full time microgrid and is connected via its two substations to the ComEd utility grid. It can operate in both grid-connected and island modes. The microgrid master controller (MMC) provides the supervisory level control needed to optimize the microgrid resources at all times. Primary control is provided locally by the appropriate resources to maintain microgrid frequency and voltage within limits when in the island mode of operation. A peak load reduction of 60% at the facility level was demonstrated. The peak load reduction at the feeder level was not demonstrated.

The net present value (NPV) of the IIT Microgrid project was determined to be approximately $4.6 million (positive) over the next 10 years and represents a benefit-to-cost ratio (BCR) of 1.38 to 1. These positive results are primarily due to the deferral of two major system upgrades. Improved reliability (fewer outages) and the efficient utilization of local generation also contributed positively to the NPV.

The project also established a fully-functional Smart Grid Workforce Training Program as part of the operation of the Galvin Center. The center provides the opportunity for hands-on experience for Smart Grid, microgrid, and energy technology and education.

San Diego Gas & Electric — Borrego Springs Microgrid (13)

The Borrego Springs microgrid is a utility distribution microgrid (UDM) with a resource portfolio that totals approximately 4.1 MW of capacity. The portfolio includes two DGs, each rated at 1.8 MW, and an energy storage system rated at 500 KW. The storage system includes a 1.5 MWh lithium ion battery.

The microgrid circuit has a peak load of 4.6 MW serving 615 customers. The circuit includes 26 customer-owned PV systems with a total installed inverter capacity of 597 kW ranging in size from 2 kW to 225 kW. The Borrego Springs substation is located at the end of a single radial 69 kilovolt (kV) transmission line in a remote area of the service territory. At the substation, the voltage is stepped down to 12 kV and serves three radial distribution circuits.

Borrego Springs does not operate as a full time microgrid. No MMC exists and control actions are done manually by the microgrid operator (MO). When grid-connected only the substation energy storage system is normally in service and is pre-programmed to charge during the day and discharge at night. Changes to its operational mode or setpoints require manual action by the MO. Initiation of a DR event is also initiated manually. In the event of an outage on the larger grid, the microgrid will also experience an outage until the DGs are manually started and the microgrid achieves island status.

Given that the microgrid load is at the end of a long feeder, island operation is beneficial when the main feeder must be taken out of service for maintenance or when it experiences an extended outage. During the demonstration period, the microgrid was operated in island mode several times in response to planned and unplanned system outages that would have otherwise affected well over 1000 consumers. A peak load reduction of greater than 15% at the feeder level was also demonstrated.

Annual savings of $1.1 million were reported as a result of reduced down time and reductions in consumer utility bills and CO_2 emissions. Additionally, the operation of the microgrid demonstrated significant opportunity for improving the reliability of the Borrego Springs community given its vulnerability of being at the remote end of a 69 kV line. However, it should be noted that the production costs for operating the microgrid resources were significantly higher than the cost of energy supplied by the grid. Whether or not the cost of the Borrego Springs microgrid would be competitive with other system improvements to improve reliability from a least cost perspective is unknown.

Hawaii Natural Energy Institute — Managing Distribution System Resources for Improved Service Quality and Reliability, Transmission Congestion Relief, and Grid Support Functions (14)

This project successfully provided Maui Electric Company (MECO) an opportunity to evaluate the capability of several advanced systems and technologies, all meant to resolve various issues that MECO faces, including high energy costs, the need to manage high penetrations of as-available renewable energy, and constraints on expanding the power system to serve load growth.

The project afforded MECO its first opportunity to operate a large BESS. MECO observed that a BESS is effective for load management, as it enables smooth variations in loads and renewable energy output. The BESS also demonstrated the ability to both provide regulation and shift times of demand on the generators. For example, charging the BESS throughout the night uses electricity generated by wind turbines and reduces wind turbine curtailment due to excess energy conditions. In addition, the project demonstrated that BESS and DR technologies are both effective in reducing peak loads on individual substations as well as the MECO system. A peak load reduction of greater than 15% at the feeder level was demonstrated.

MECO now has the experience to integrate distributed and renewable energy resources effectively through operation of its central generators and transmission system. As a result, the system will be able to support larger amounts of as-available renewable energy resources, improved system stability, higher reliability of supply, and lower costs for MECO customers.

No financial information was provided for benefits or costs.

3.2.2 RDSI Projects Still in Progress

Only two of the nine RDSI projects have not yet submitted FTRs. When received and accepted all FTR's will be available at www.smartgrid.gov when the project is completed.

City of Fort Collins —Research Development and Demonstration of Peak Load Reduction on Distribution Feeders Using Distributed Energy Resources for the City of Fort Collins (15)

The City of Fort Collins, Colorado, demonstrated integrated operation of distributed generation, renewable energy, and DR resources, collectively known as DER. The primary aim of the project was to demonstrate the monitoring, aggregation, distribution system integration, dispatch, and verification of DER for reducing peak load on two feeders within the Fort Collins Utilities electric distribution network.

The project aggregated over 3.5 MW of DER to demonstrate the technical feasibility and benefits of DER to asset owners and distribution network operators. The DER included a variety of sources including reciprocating engines, fuel cells, combined heat and power (CHP) units, PV, micro-turbines, PHEVs in vehicle-to-grid configuration, and conventional backup generators from approximately five different participant locations. An aggregation of heating, ventilation, and air conditioning (HVAC) loads, process loads, and thermal storage contributed to DR capabilities. Energy efficiency (EE) upgrades contributed toward the long-term reduction of loads on the selected feeders.

The project demonstrated a 20% reduction in peak load at the distribution feeder level on three of five test days. In addition, an asset response rate was computed by the project team to measure overall effectiveness of the peak load management system. Generation resources responded greater than 92% of the time and load shedding resources responded about 79% of the time. In addition, Ft. Collins furthered the goals of its local energy policy, including the development of a smart grid-enabled distribution system in Fort Collins, expanded use of renewable energy, increased energy conservation, and peak load reduction.

No financial information was provided for benefits or costs.

The City of Fort Collins' DER demonstration project was field-completed in September 2013. Further details are expected when the FTR is submitted in June 2015.

University of Nevada, Las Vegas — Decreasing the Peak Demand in the Desert Southwest (16)

The University of Nevada, Las Vegas (UNLV), is seeking to decrease peak demand in Nevada through this RDSI demonstration project. In cooperation with Pulte Homes and Nevada Energy (NV Energy), Pulte built a green-field development of 185 homes, called Villa Trieste, in which they designed each home for optimal energy efficiency. Pulte incorporated many energy conserving features into the homes, including solar PV systems, low-emissivity windows, tankless water heaters, and high seasonal energy efficiency rating air conditioning systems. UNLV has observed efficiency improvements in excess of 45% over conventionally designed homes during summer days.

The project is also demonstrating peak demand reduction in newly constructed residential buildings through distributed BESSs and an intelligent agent DR (IADR) program. The IADR uses a data communication gateway to connect programmable thermostats to the UNLV server. When the results from IADR events are applied to the already-efficient Villa Trieste homes, realized peak energy reduction is between 74% and 80%, compared to code-built homes. UNLV has not yet determined the total impact on peak load reduction at the feeder level.

While the reduction in Villa Trieste's grid-demanded energy during the peak period of an IADR event is encouraging, the energy consumption profiles indicate that a substantial secondary peak occurs. That secondary peak occurs about an hour after an IADR event ends and is more than 150% greater than the maximum demand during an unregulated day.

UNLV's RDSI project is ongoing and is expected to conclude at the end of June 2015. UNLV plans to implement an energy prediction model and the BESS during the summer of 2015. Additional future areas of study include the determination of total peak load reduction at the feeder level, the amount the IADR program shifts or shaves peak load, and an analysis of the effects of energy storage.

No financial information was provided for benefits or costs.

3.3 RDSI Program Observations

The aim of the RDSI program was to develop and demonstrate new distribution system configurations integrated with distributed resources. The projects were specifically focused on demonstrating microgrids or their enabling elements, such as communications and control strategies for DR, distributed renewable generation systems, storage technologies, advanced sensors, and energy efficient building sub-systems. Each project sought to achieve a reduction of at least 15% of the power that would otherwise be normally supplied by the distribution substation or distribution feeders during peak load periods. Seven of the nine projects have completed field demonstrations and FTRs have been received. FTRs have not yet been received for the Ft. Collins and University of Nevada projects.

The seven completed projects collectively met the aim of the RDSI program. The three microgrid projects—Santa Rita Jail, IIT, and Borrego Springs—demonstrated the ability to operate in both grid-connected and island modes and each met substantial reductions in peak load. These projects all employed energy storage systems which enabled the integration of various types of DER including renewables and DR.

The Hawaii National Energy Institute's integration of smart grid technologies and energy storage also achieved substantial reduction in feeder peak load and supported the integration of renewables. Con Edison of NY aggregated DR resources using its DRCC and successfully offered them to the NYISO market. ATK integrated energy storage with wind to shift the load profile although it did not achieve a 15% peak load reduction. Mon Power's WVSC was terminated before its completion.

From a business case perspective only two of the projects—the IIT microgrid and Con Edison's DRCC reported positive business cases. The economics of IIT was driven primarily by the deferral of two large capital projects and a substantial benefit in loss prevention due to the improvement in reliability afforded by the microgrid. The economics for the Con Edison DR project was driven by its market participation with the NYISO through the successful aggregation of DR resources by the DRCC. Four projects either didn't report economic results or the results reported suggested that the benefit to cost ratio was less than one. One project, Mon Power, was determined to not be economically feasible and was terminated in September 2013.

While the technical results for the completed projects were largely successful, the cost and benefit information provided generally suggests that the business cases for these projects are not compelling unless specific incremental opportunities exist for creating value. Such opportunities may include the deferral of major capital investments and significant loss prevention due to improved reliability and resiliency. Finding an acceptable way to value the improvements in reliability, resiliency, and environmental improvement is necessary for properly judging overall project economics. The economic value of Con Edison's DRCC may be an exception given the significant revenues expected from its DR programs under the NYISO's current pricing.

FTRs have not been received for Ft. Collins and the University of Nevada. Ft. Collins is demonstrating the aggregation of DR and DER resources to reduce feeder peak loading. The University of Nevada is also demonstrating the aggregation of DR and EE in homes. FTRs for both projects are expected to be submitted as noted in Table 2.

4. Smart Grid Demonstration Program

As presented in Section 1.2 above, two types of smart grid projects were selected for the SGDP — regional demonstration projects and energy storage projects. The status of each project is presented in Table 3 and Table 4 below:

4.1 SGDP Regional Demonstration Project Status

Project	FTR Received[5]	FTR Projected
Battelle Memorial Institute	NR	May 2015
AEP Ohio	6/30/14	
LA Department of Water & Power	NR	Sept 2016
Consolidated Edison Co of NY	12/28/14	
Southern California Edison	NR	Dec 2015
National Rural Electric Cooperative Association	3/16/15 (draft)	
Kansas City Power & Light Co	4/30/15 (draft)	
Center for Commercialization of Electric Technologies	2/23/15	

[5] Designates projects for which a final, approved FTR has been received or a draft FTR has been received but has not yet been approved by the date of publication. "NR" indicates that the FTR has not yet been received.

Project	FTR Received[5]	FTR Projected
Long Island Power Authority	4/27/15	
SuperPower	NR	Dec 2016
Pecan Street Project	2/27/15	
Boeing Co	12/10/14	
Northeast Utilities Service Co (AMR)	2/24/15 (draft)	
Oncor Electric Delivery Co	12/6/13	
Northeast Utilities Service Co (Urban Grid Monitoring)	NR	Mar 2016
Power Authority of the State of New York	10/17/13	

Table 3 Status of SGDP Regional Demonstration Projects

4.2 SGDP Regional Demonstration Project Results

As of the date of this report, eleven of the sixteen SGDP regional demonstration projects have completed their field demonstrations and FTRs have been received. The FTRs for these completed projects may be found at www.smartgrid.gov when they are published.

4.2.1 Completed SGDP Regional Demonstration Projects

AEP Ohio — gridSmart® Demonstration Project (17)

Through a community-based approach, AEP Ohio incorporated a full suite of smart grid technologies for 110,000 consumers in an area selected for its concentration and diversity of distribution infrastructure and consumers. AEP Ohio organized and oriented the project, called the gridSMART® Demonstration Project, around technology, implementation, and operations; consumer and stakeholder acceptance; and data management and benefit assessment.

The project included multiple technology enhancements to the infrastructure of the project area, including the addition of the following foundational technologies and programs:

- Advanced metering infrastructure (AMI), which enabled two-way communications with consumers' meters
- Distribution automation circuit reconfiguration (DACR), which automated distribution assets

- Volt/VAr optimization (VVO), which enabled voltage control leading to a reduction in energy consumption and reduced peak demand
- Consumer programs linked to AMI-driven technologies, which unlocked cost-saving opportunities through enhanced communication

The integration of these technologies and programs provided a foundation for two-way communications with consumers and paved the way for related consumer programs and products, such as real-time pricing and studies involving electric vehicle (EV) integration.

A number of benefits resulted from the deployment of smart grid technologies including a reduction in CO_2 emissions of 16.9 metric tons by avoiding 1,952 truck rolls per year, higher customer satisfaction, a reduction in customer interruption minutes by 1.6 million minutes, improvements in the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI), reduced energy consumption by 3% and demand by 2-3% using VVO, and a savings of 7,781 gallons of gasoline by using EVs. None of these benefits were monetized, but meter reading labor costs were reduced $452K annually.

AEP recognized that the design and implementation of multiple smart grid technologies require significant interdepartmental coordination within the utility.

Consolidated Edison Company of New York — Secure Interoperable Open Smart Grid Demonstration Project (18)

Con Edison demonstrated a secure, interoperable, open smart grid, which reduced electricity demand and increased energy efficiency and reliability. The project, located in New York City and its New York and New Jersey suburbs, has one of the highest load densities in the world, representing a complex and diverse test bed.

The project demonstrated distributed thermal and battery storage, high-tension monitoring, AMI, home area networks (HAN), building management systems (BMS), meter data management systems (MDMS), solar PV systems, and smart EV charging. Other new technologies developed through the project include management systems for DR resources and DER, a decision management engine that aggregates electricity supply data called the Integrated System Model (ISM), an adaptive stochastic controller, and an intelligent maintenance system called the Smart Grid Disturbance Monitor.

The project illustrated how data from disparate systems can be securely communicated, integrated, and displayed to the control center operator through the use of decision-aid tools, helping operators identify problem areas and prioritize corrective action in both normal and contingency operations. Con Edison anticipates that these new technologies will be scalable across urban utility territories nationwide to enable the growth of DER and DR.

Con Edison reported substantial savings and opportunities. Approximately $2 million per year in operational savings from the meter reading process has been experienced. Between $1.1 million and $3.7 million in additional annual income may be available to DR resources through participation in the NYISO capacity market.

National Rural Electric Cooperative Association —Enhanced Demand and Distribution Management Regional Demonstration (19)

The National Rural Electric Cooperative Association (NRECA) organized this demonstration project to install and study a broad range of advanced smart grid technologies that spanned 23 electric cooperatives in 12 states. Over 205,444 pieces of electronic equipment and over 100,000 minor items (bracket, labels, mounting hardware, fiber optic cable, etc.) were installed to upgrade and enhance the efficiency, reliability, and resiliency of the power networks at the participating co-ops. The purpose of the project was to advance the co-ops' familiarity and comfort with emerging smart grid technologies.

NRECA deployed 12 distinct smart grid technologies. These technologies were classified into three major technology areas—enabling technologies, DR technologies, and distribution automation (DA) technologies. Each of the 23 cooperatives participated in each of these technology areas to varying degrees. Overall results in each technology area are summarized below.

Enabling technologies include AMI, supervisory control and data acquisition (SCADA), meter data management, and communications. Implementation issues were experienced for each of these technologies. Power line carrier (PLC) for communications was problematic, but was the only option for some of the rural service territories. Once in service these technologies did improve operations. Meter reading, outage management, voltage monitoring, remote disconnection, and customer service was improved. In some cases power theft was detected. The value of these and other benefits in this technology area were not quantified.

DR technologies include in-home displays (IHD), web portals, pre-paid metering, DR over AMI, and interactive thermal storage. Many of the cooperatives stated the IHDs and web portals increased customer awareness about electricity use; however, none had quantified the energy savings.

Some participants experienced installation delays and issues with remotely controlling devices. Despite these issues, most DR programs over AMI met expectations. One cooperative can now control 10%-15% of its peak load, one can reduce demand by 2,100 kW, and another has saved $700,000 annually using the program. Several other cooperatives noted that they believed the savings were significant, but they have not yet quantified them.

One cooperative installed grid interactive thermal storage water heaters. These units heat water to very high temperatures (185 °Fahrenheit) during times when grid electricity usage is low, and thus cheaper, and then mix the hot water with cold water to the desired usage temperature. As the units are addressable over an internet provider (IP) address, they can be used to provide fast frequency regulation services to wholesale ancillary service markets. The revenue received by modulating the charge rate of these devices based on a signal received from the overseeing Independent System Operator (ISO) can entirely offset the cost of energy to provide hot water for a home or business. The units have worked exceptionally well, and the initial results are promising.

DA technologies include renewables integration, smart feeder switching, advanced volt/VAr control, and conservation voltage reduction (CVR). Two cooperatives installed systems (battery storage and a 1 MVAr ABB Statcom) to improve the integration of renewables but the value of this benefit has not been quantified.

Participating cooperatives reported smart feeder switching was effective in preventing outages, improving outage detection, reducing outage duration, and locating distribution system faults. One cooperative has reduced outage times by an average of 75 minutes. Another cooperative has experienced 37 automated switching events, which prevented more than 20,000 customers from experiencing an outage. Those customers otherwise would have endured an outage lasting an average of 1.5 hours. Participants also reported that the ability to remotely switch substations that are out of service has saved significant substation maintenance time. None of these benefits were quantified.

Solid state voltage control has provided excellent localized voltage support, reduced distribution circuit flicker, and improved PQ for members of one cooperative. One cooperative reported that the value of CVR to improve PQ is worth the investment. Another cooperative reported a savings of $18,000 in 2012 and $41,000 of savings in 2013 from CVR.

Kansas City Power & Light Co — Green Impact Zone Smart Grid Demonstration (20)

Kansas City Power & Light (KCP&L) is deploying a suite of smart grid technologies called the Green Impact Zone which includes advanced renewable generation, storage resources, leadingedge substation and DA and controls, energy management interfaces, and innovative customer programs and rate structures. The project area is focused on an economically challenged area of Kansas City, Missouri, which is served by KCP&L's Midtown substation and impacts approximately 14,000 commercial and residential customers.

The KCP&L smart grid demonstration project includes 23 distinct technologies split into five general categories. These categories and the results achieved are discussed below:

Smart Metering: An AMI system was deployed in the project area (approximately 14,000 meters) using communicating smart meters with a wireless two-way communication network. This enabled real-time communications between the meters and the newly deployed MDMS which is also integrated with other KCP&L's systems including the customer information system (CIS), distribution management system (DMS), outage management system (OMS), and the DERMS. The smart metering subproject improved meter reading times and accuracy, sped up meter problem detection and resolution, and allowed for remote connection and disconnection. It outperformed the legacy AMR system in a number of areas. The value of these benefits to KCP&L's operations was not quantified.

Smart End-Use: The smart end-use sub-project deployed a home energy management platform (HEMP) and TOU rate plan to increase customer adoption of consumption awareness and management techniques, as well as expand KCP&L's demand management capabilities. Together, the HEMP and TOU rate enable customers to manage their energy consumption and associated costs directly. HEMP provides KCP&L with DR assets that can be called on during peak demand times to help increase distribution grid stability and decrease operating costs. The smart end-use subproject helped customers understand more about their energy usage and take steps to save energy. TOU participants, on average, reduced their on-peak energy consumption by approximately 10% and saved an average of $68 on an annual basis over the 4-month summer rate period.

Smart Substation: A new substation protection and control network, microprocessor-based protective relays, associated hardware, and applications were installed at the Midtown substation. This will enable advanced functionality to provide more reliability, efficiency, and security. These substation level benefits were not quantified.

Smart Distribution: The smart distribution sub-project deployed a state-of-the-art DMS and advanced DA network. The DMS monitors and controls the state of the distribution network at all times, and serves as the primary point of integration for the facilities, consumer, electrical system, load, DER, and real-time substation and feeder information. It solves reliability issues through its Distribution Network Analyses applications. The smart distribution subproject provided grid operators with improved visibility and operational control of the distribution grid and significantly improved grid reliability. SAIDI was reduced by 35% for the customers in the study area (262 minutes with Fault Location, Isolation, and Service Restoration (FLISR) versus 403 minutes normally). None of the identified benefits were quantitatively valued, but the asset condition monitoring program detected an internal arc in a newly installed substation power transformer, avoiding the loss of a $1.25 million dollar asset.

Smart Generation: The smart generation sub-project deployed a state-of-the art DERMS to manage several types of DER including DR load curtailment programs, a BESS, grid-connected distributed PV, and EV charging stations. This subproject provided significant operational benefits in its ability to manage all DR assets, DER, and load reduction events. The BESS produced approximately $3,000 in savings by providing energy time-shifting services for the 2014 Southwest Power Pool (SPP) day-ahead energy market. The BESS also provided load reductions of 200 kW to 500 kW at the distribution substation or circuit level during peak load periods. Analysis showed that to provide effective generation or distribution capacity deferral, a BESS should be configured with 4 MWh to 5 MWh of storage for each MW of capacity. Although not a microgrid, the project also demonstrated that the BESS could island a portion of a distribution circuit and sustain power to customers during an outage of the grid supply.

The premise energy storage system (PESS), which is a residential BESS installed at the Smart Grid Demonstration House, when operated for TOU energy cost savings, could potentially save the customer $638 annually. In addition, by discharging during on-peak times the PESS resulted in a reduction of at least 2 kW in customer peak load, providing the utility the equivalent potential generation and distribution capacity deferral benefits. When operated for renewable energy time shift, the PESS could store solar energy that was generated off-peak and release 2,900 kWh of stored energy annually during on-peak periods, potentially saving the customer $255.

Public EV charging provided increased kWh energy sales of approximately 7 kWh per charge. Even more significant, each charge avoided the consumption of approximately 1 gallon of gasoline.

KCP&L has submitted its draft FTR, but further revisions are expected and the final version is expected in May 2015.

Center for Commercialization of Electric Technologies — Technology Solutions for Wind Integration in ERCOT (21)

The Center for the Commercialization of Electric Technologies (CCET) demonstrated new response mechanisms to help manage fluctuations in wind generation in the Electric Reliability Council of Texas (ERCOT) transmission grid. CCET accomplished this solution by utilizing better system monitoring capabilities, enhanced operator visualization, and improved load management.

Sustained winds can be harnessed using wind turbines to provide a source of clean and renewable energy. However, due to periods of too much and too little wind, this source has limited dependability. Through this project, CCET demonstrated how the use of synchrophasor technology, which measures power variations in real time, can help integrate more wind resources while more effectively managing wind power's effects on the grid. Given the critical nature of synchrophasor data, cyber security testing was done on a phasor data stream between a "virtual Transmission Owner/Utility" and a "virtual ISO." Several vulnerabilities were identified and resolved.

CCET also assessed how battery storage can supplement wind turbines to improve overall feasibility of wind power. The primary focus of the study included both the ability of a BESS to perform various grid functions, as well as the economic viability of implementing the system. Researchers tested frequency response, demonstrating that when frequency went below 60 Hz, the battery could automatically ramp up to meet demand. They also tested ability of the BESS to provide wind ramping/load leveling, showing that the BESS could respond correctly according to generation and load variability within seconds. After running several economic models, the team determined that the most economically viable system was a 1 MW BESS on a distribution network owned by a utility in a regulated market (with demand charge management). CCET reported that the NPV for the BESS was positive ($491K), but concluded it was not compelling for a utility to invest.

CCET also demonstrated using pricing incentives that customers are responsive to pricing systems and will modify their consumption and reduce their peak load significantly to improve system efficiencies. One experiment showed that consumers would reduce their peak demand, given a day-ahead notice and a monetary incentive by an average of 15%. Another experiment demonstrated that homeowners are responsive to pricing systems that will shift their electric load significantly to improve system efficiencies. Comparisons of overall electricity consumption between the pricing and control groups indicated a 4% increase in consumption during wind enhanced periods.

CCET also demonstrated that a fleet of electric trucks could provide fast response regulation service (FRRS). A set of eleven Frito-Lay delivery trucks were aggregated to provide at least 100 kW of FRRS. Unfortunately this application for providing FRRS was shown to not be economically viable.

This project also included a component to monitor and assess the dynamics of a solar community as it interacts with the grid. CCET analyzed several PQ parameters, including total harmonic distortion of voltage (THDv), total harmonic distortion of current (THDi), and voltage at the distribution level. CCET found that THDv peaked at 4.12%, which satisfies the IEEE Standard 519 requirement that THDv should remain under 5%. Measurements of THDi indicated that higher levels of harmonic distortions might exist on distribution circuits that feed high concentrations of homes with solar PV, compared to those serving homes with little or no PV. This may be an anomaly due to the measurement method used for THDi. Further investigation is needed to determine the impact of this THDi measurement.

Long Island Power Authority — Long Island Smart Energy Corridor (22)

The Long Island Power Authority (LIPA) has teamed with Stony Brook University and Farmingdale State College to deploy and demonstrate a variety of smart grid technologies. The project is located along the Route 110 business corridor on Long Island, New York, creating a "Smart Grid Corridor."

The LIPA Smart Grid Corridor project illustrated how smart grid technologies can be integrated from substations to end-use loads. It encompassed three technology study areas: AMI, DA/substation automation (SA), and customer systems assets. Seminars, workshops, and courses related to smart grid technologies were held by Stony Brook University and Farmingdale State College for both students and the general public.

The overall plan was to deploy an AMI System, DA devices, and substation remote terminal Units (RTU). LIPA has deployed 1,620 residential smart meters and 930 commercial meters. Direct load control technologies including thermostats, load control devices, smart plugs, and web portals were deployed in participating customers' homes. In order to support DA and SA, LIPA deployed eighteen overhead automatic sectionalizing switches, supervisory control for six underground pad mounted transformers, and 51 two-way capacitor bank controllers.

LIPA aimed to validate how smart grid technologies can reduce customer costs for electricity, decrease peak loads, enhance reliability, and engage customers. It also expected to address emerging cyber security concerns with smart grid technologies and facilitate the development and commercialization of new smart grid technologies and tools.

Development of relevant curricula to train the workforce that will be needed for significant expansion of smart grid, renewable, and PHEV technology deployment was also a goal. Stony Brook University faculty team enhanced and developed new curriculum and delivered seminars on smart grid topics**.**

Farmingdale State College developed live demonstration models to enable people to gain a better understanding of smart grid technologies and smart meters. They have erected an Energy Smart House incorporating a solar PV system, solar thermal system, smart louvers, a smart meter, and a smart plug. In addition, Farmingdale implemented a small-scale wind farm (7.2 kW) that can feed back into the campus power grid. It also deployed a solar carport that produces 94 kW and supports a 20 PHEV charging station. The solar energy can also be fed back into campus grid and be monitored online. Farmingdale also held several workshops and seminars about smart grid technologies and their campus demonstration.

LIPA identified a number of potential economic, reliability, and environmental benefits but concluded that they are expected to be minimal, given the size and scope of this project. For the segment of customers participating in the smart TOU rate, about 50% experienced an average bill savings of $89 over a one year period. All 44% of participants who were unsuccessful at realizing a savings on their annual energy bill reverted back to their old rate. No additional cost or benefit data was provided.

LIPA’s FTR dated April 27, 2015 has been accepted.

Pecan Street Inc. — Pecan Street Project Energy Internet Demonstration (23)

Pecan Street Inc. is implementing an “Energy Internet” at the Robert Mueller mixed-use development in Austin, Texas. The smart grid technologies that the project is demonstrating include home energy monitoring systems, a smart meter research network, energy management gateways, distributed generation, EVs with Level 2 charging stations, and smart thermostats. These technologies are integrated into a smart grid that links 1,000 residences, 25 small commercial properties, and three public schools.

Through the use of Pecan Street’s home energy monitoring systems, customers can view their energy use in real time at the device level, set and track utility bill budgets, manage the electricity use of individual appliances, and sell energy back to the grid. And, through the collection of electricity consumption data from home energy monitoring systems deployed in 661 homes, Pecan Street has created and owns the world’s largest disaggregated residential energy database, with over 1,000 home years of appliance-level energy consumption measurements.

Pecan Street procured 471 AMI smart meters that Austin Energy deployed on a dual socket configuration in Mueller and the surrounding neighborhoods to mimic the utility-side smart meters. These meters are industry standard and act as a HAN gateway. Data is collected in 15-minute whole-home readings. The deployment of these meters was a success. This meter network constitutes the nation's only research meter network where companies can develop and verify the performance of hardware and software using actual customer data provided by representative smart meters.

To encourage the adoption of solar among research participants, Pecan Street offered additional rebates in partnership with Austin Energy's rebates for installation of residential PV. Prior to Pecan Street's enhanced solar rebate offering, 11 homes in Mueller had installed PV systems. At the end of September 2011, when Pecan Street's solar rebate expired, over 200 homes in Mueller had installed roof-top PV systems. The business case for residential PV was found to be positive with the rebate included but negative without it.

To date, Pecan Street has incentivized the purchase or lease of 69 EVs all with Level 2 charging stations located in and near the Mueller community. PV generation provides more than enough energy to fully offset EV charging demands.

The Boeing Company — Boeing Smart Grid Solution (24)

The Boeing Smart Grid Solution project team successfully tailored and demonstrated a combination of processes, techniques, and technologies that have been successfully implemented in the commercial, defense, and intelligence communities to identify, mitigate, and continuously monitor the cybersecurity of critical systems.

After conducting a cybersecurity risk-based assessment of the Pennsylvania Jersey Maryland Interconnection's (PJM) critical network and information systems at the outset of the project, the project team completed multiple iterations of cybersecurity solution design, development, and deployment. Multiple cybersecurity solutions were deployed across a variety of PJM's systems. All of these are suitable for replication across the electric sector and/or across the energy sector as a whole.

Northeast Utilities Service Company — Automated Meter Reading-Based Dynamic Pricing (25)

Northeast Utilities Service Company (NUSCO) implemented an automated meter reading (AMR)-based dynamic pricing project that included five communities within NUSCO's service area (Jamaica Plain, Newton, Hopkinton, Waltham, and Framingham), offering a combination of mixed-income neighborhoods and middle/upper-middle class suburbs.

In this AMR project, NUSCO designed a smart grid pilot program which offered residential participants a set of new electricity rate options and enabled participants to view their real-time energy consumption and cost information via an IHD and web portal. NUSCO also sent air conditioner load control signals, measured DR load, and conducted event-specific impact evaluations via the two-way communications pathway in the pilot program. Data collection spanned two summer seasons over a period of approximately 24 months.

The technology architecture was designed to leverage existing, deployed AMR meters by connecting these meters to NUSCO and the relevant internal processes through a set of in-home, cloud-based, and back-office technologies.

The AMR project's overall goal was to provide AMI-like functionality and examine its viability by leveraging existing AMR infrastructure. More specifically NUSCO aimed to achieve peak load and energy consumption reductions of at least 5%, identify customer perceptions and views on pilot offerings, and obtain technical, economic, and marketing information that can be used to inform future smart grid decisions.

Four customer test groups were established with each provided a different rate structure.

- Enhanced information—access to information on energy consumption and only on a standard rate
- Peak time rebate (PTR)—Five dollar rebate for participation in critical peak events via NUSCO control of a smart thermostat and on a standard rate
- Time-of-use (TOU) rate with critical peak pricing (CPP)
- TOU/CPP and load control)—smart thermostat controlled by NUSCO during CPP events

Peak load reductions varied among the four test groups (3% to 18%), were generally greater during the winter peak, and were greatest for the TOU participants. Similarly, only participants in the TOU rate groups realized a reduction in energy consumption (less than 2%) with a corresponding reduction in energy bills of approximately 4%.

The NUSCO AMR project demonstrated how the electricity energy usage and demand of residential customers change by incorporating new rate options, dynamic pricing, and smart meter information. It also demonstrated AMI-like features of AMR without incurring the cost and disruption of upgrading to a new AMI system. NUSCO also conducted several customer evaluation surveys during the project which identified customers' perceptions on different aspects of the pilot program.

The project successfully demonstrated that the current technology architecture is capable of achieving AMI-like features through the collection of interval meter data, without the entire system upgrade and large capital investment. NUSCO also investigated the cybersecurity risks of the pilot architecture and successfully determined that the risks are relative low and the pilot program meets security requirements.

NUSCO will be using the results of this pilot to inform its grid modernization plan development efforts.

Oncor Electric Delivery Company — Dynamic Line Rating Project (26)

Oncor's project demonstrated that dynamic line rating technologies identify significant additional capacity above static ratings or ambient-adjusted ratings. While quarterly results varied, the average increased real-time capacity delivered by dynamic ratings was 6%-14% greater than ambient-adjusted rating for 345 kV lines and 8%-12% greater than ambient-adjusted rating for 138 kV lines. The availability of that added capacity ranged from 84% of the time under all operating conditions to 91% of the time when outages and anomalies were excluded from the data.

Oncor also integrated the DLR system with ERCOT's economic dispatch tool. Dynamic ratings have been integrated into transmission owners' control systems before, but Oncor's project represents the first time that dynamic ratings were automatically incorporated directly into a system operator's economic dispatch tool.

Oncor found that the economic benefit of DLR was difficult to assess, especially as it related to congestion mitigation. This is because ERCOT does not have the capability to perform real-time "what-if" scenarios of economic benefits with and without dynamic ratings. Furthermore, the congestion of transmission lines is so volatile and transient that it is difficult to compare day-to-day or year-to-year operations. Although Oncor and ERCOT could not evaluate the real-time impact of the DLR technologies on system congestion, Oncor's studies suggest that DLR systems can yield significant congestion-relieving benefits.

New York Power Authority — Evaluation of Instrumentation and Dynamic Thermal Ratings for Overhead Lines (27)

The New York Power Authority (NYPA) deployed DLR technologies and determined that a DLR system can provide "better knowledge" of a line's actual capacity than using static ratings. The project included the installation and maintenance of DLR instrumentation along three 230 kV line sites in northern New York. These sites were chosen because of their close proximity to wind generation, which would help NYPA to determine a correlation between wind farm output and transmission line capacity.

In most cases, NYPA found that the dynamic ratings were significantly greater than the static ratings of the circuits studied (generally ranging from 30%-44% above the static rating), suggesting that DLR technologies can be successful tools for integrating additional transmission capacity in real time. For the specific line sections that NYPA studied, this is particularly true during periods of high wind farm output (i.e., when the wind is blowing).

The project revealed that DLR devices are reliable but require certain conditions to be met in order to operate accurately. The project's primary difficulties were related to the discovery that DLR devices cannot gather accurate data when lines are lightly loaded. NYPA also found that DLR systems are technically challenging to implement; nevertheless, the utility was able to gather accurate data on the DLR systems.

The most significant benefit of this project was an enhanced understanding of various DLR technologies to facilitate future deployments. NYPA was able to evaluate the unique advantages and disadvantages of each technology it studied. Once NYPA more fully implements DLR technologies in its transmission operations, it expects dynamic ratings to help reduce the cost of delivered energy, reduce greenhouse gas emissions, and increase grid reliability.

The monetized value of the improved capacity margins provided by the dynamic ratings was not provided.

4.2.2 SGDP Regional Demonstration Projects Still in Progress

Seven of the sixteen SGDP regional demonstration projects have not yet submitted FTRs. When received and accepted all FTRs will be available at www.smartgrid.gov when the projects are completed.

Battelle Memorial Institute — Pacific Northwest Smart Grid Demonstration Project (28)

Battelle Memorial Institute (Battelle) is collaborating with 11 utilities, two universities, and several technology partners across five states and three climatic regions, spanning the electrical system from generation to end-use and containing all key functionalities of the future smart grid.

The demonstration, called the Pacific Northwest Smart Grid Demonstration Project, is validating more than 20 types of responsive smart grid assets; is providing two-way communication between DER, energy storage, demand assets, and existing grid infrastructure; is quantifying smart grid costs and benefits; and is validating new business models. The demonstration has developed a single, integrated, incentive-signaling approach to transactive control and is testing and validating its ability to continuously coordinate the responses of smart grid assets to meet a wide range of operational objectives. The project is also among the first to engage distributed control to mitigate wind integration issues. Microgrid islanding is also being evaluated for its potential to enhance reliability and relieve energy demand.

The project utilizes a smart grid application referred to as transactive control to integrate smart grid assets at utilities throughout the Bonneville Power Administration balancing area to provide regional benefits in facilitating the integration of renewable energy resources. This benefit will provide real-time response of the assets to transactive control signals representing an integrated view of regional grid conditions. Other expected benefits include a more cost-effective, clean, and reliable electricity supply; increased grid efficiency, reliability, and intelligence; and customers who are empowered to conserve energy.

Some of the project goals include:

- Validation of smart grid costs and benefits for customers, utilities, regulators, and the nation that will lay the foundation for future investment
- Advance standards and communications and control methodologies for a secure, scalable, interoperable smart grid for regulated and non-regulated utilities
- Facilitate the integration of wind and other renewables

The Pacific Northwest Smart Grid Demonstration Project involves twelve subprojects across which multiple combinations of smart grid assets are being deployed. These assets include DA, CVR, smart meters, energy storage, DER (including backup generators and distributed wind, hydro, and solar resources), controllable loads, and end-user DR devices. Each subproject has established specific goals that are consistent with the overall goals of the larger project.

Final analysis of 57 of 81 test cases is complete. Progress to complete 16 of the 24 remaining analyses is underway. Work to complete the development of a transactive data visualization tool and a VOLTTRON-based[6] transactive node is underway. In addition, a regional symposium was held in Spokane, Washington, on April 1, 2015. Participants in the symposium shared high-

[6] VOLTTRON is an innovative distributed control and sensing software platform that was developed by the Pacific Northwest National Laboratory to build applications for more efficiently managing energy use among appliances and devices, including HVAC systems, lighting, EVs and others.

level project results with stakeholders, recognized accomplishments, and discussed the future of smart grid technology in the region.

Battelle's Pacific Northwest Smart Grid Demonstration Project is in the process of compiling its draft FTR which the team expects to submit by the end of May 2015.

Los Angeles Department of Water and Power — Smart Grid Regional Demonstration Project (29)

The Los Angeles Department of Water and Power (LADWP) aims to develop new smart grid technologies, quantify costs and benefits, validate new models, and create prototypes to be adapted nationally. The project consists of several broad initiatives in the categories of customer behavior (CB), DR, AMI, EV integration, and next-generation cybersecurity.

LADWP's goal is to demonstrate smart grid technologies that embody essential and salient characteristics and present a suite of use cases for national implementation and replication. These use cases will collect and provide the optimal amount of information necessary for customers, distributors, and generators to change their behavior in a way that reduces system demands and costs, increases energy efficiency, optimally allocates and matches demand and resources to meet that demand, and increases the reliability of the grid.

The CB initiative consists of CB studies and several surveys about LADWP customer attitudes toward various smart grid components. No new technology was deployed in this portion of the project. Initial results indicate that across two DR events 64%-78% of survey respondents participated in the event and that on average, respondents participated for 1-2 hours of the 3-hour events.

The DR initiative utilizes AMI communications infrastructure and smart meters that enable LADWP to initiate DR events. It also deployed building to grid integration (B2G) technology that connects building automation systems, on-site renewables, other generation, and storage devices to the grid. LADWP will use this information for grid optimization, market-based pricing, and improvements in efficiency, reliability, and PQ for commercial and industrial customers. The DR initiative also utilizes HANs to connect appliances, on-site renewables, and storage devices in homes to the grid for access to real-time energy usage and pricing information and the ability to react to DR events from LADWP. Initial results from the DR initiative include the identification of the energy use in buildings, helping determine the greatest opportunities for DR/EE. Thermostat data has also been collected and several DR events have occurred with eleven buildings.

The EV initiative utilizes smart EV charging stations and battery aggregation, renewables and EV battery integration, an operational microgrid (i.e., an aggregation of EV-related resources), a ride/car share program at LADWP, and EV test bed sites at University of Southern California (USC) and University of California-Los Angeles (UCLA). LADWP has not reported any EV results to date, but it has installed a number of technologies to support EVs including over 1,000 EV chargers, 74 distribution transformer monitors, and other supporting equipment.

The AMI demonstration includes smart metering, a communications network, and the back office operations and applications that will enable, support, and integrate all aspects of the project. The data provided by smart meters will be used by various components of the DR, CB, and EV projects. Revenue meters will be installed in a number of microgrids (i.e., the areas with two-way communication with meters, and capability to deploy DR) within the LADWP service area. LADWP is retrieving AMI data every eight hours from 51,000 meters. LADWP triages, monitors, coordinates, and maintains the system while identifying outages, meter tampers, and energy discrepancies more quickly.

The next-generation cybersecurity initiative involves the demonstration of technologies to show grid resilience against physical and cyber-attacks, an operational testing approach for components and installed systems, and a redefined security perimeter to address smart grid technologies. So far, LADWP has not observed any specific cyber-attacks within the demonstration infrastructure.

No business case information or quantification of benefits was provided.

LADWP's project is ongoing and is expected to conclude and the FTR submitted in September 2016.

Southern California Edison — Irvine Smart Grid Demonstration (30)

Southern California Edison (SCE) is demonstrating numerous smart grid technologies needed to meet state and federal renewable energy policies for the year 2020. The Irvine Smart Grid Demonstration (ISGD) is investigating the use of phasor measurement technology to enable transmission substation-level situational awareness and is also evaluating the latest generation of DA technologies. SCE is also demonstrating that CVR can reduce customer energy consumption. At the consumer level, the project includes a demonstration of home area network devices, such as energy management systems, smart appliances, energy storage, and roof-top PV systems in consumer homes. DR programs involving energy storage devices and PHEV charging equipment is also included. The project is currently in still in progress.

As of March 25, 2015, SCE has reported results in a number of areas. At the consumer level, none of the homes achieved "zero net energy" (ZNE) but one home did achieve 88% of ZNE. Smart grid technologies needed for DR were demonstrated. The residential energy storage units charged and discharged based on setpoints for net household demand and the EV systems responded to DR event signals as expected. At the distribution system level, the larger energy storage system operated as expected, charging and discharging according to a defined schedule, and CVR reduced distribution system voltage. SCE also used phasor measurement technology installed at a transmission-level substation to help detect changes in distribution circuit load from DER, enhancing SCE's situational awareness of the grid. No cost/benefit information has been provided to date. Results of other field experiments are forthcoming when the FTR is received.

SuperPower, Inc. — Fault Current Limiting Superconducting Transformer (31)

SuperPower, Inc. (SuperPower) is developing key technologies necessary to enable future (outside of this project) construction of a prototype superconducting fault current limiting (FCL) transformer. The project has evolved considerably since its beginning in 2010. Initially with SPX Transformer Solutions (SPX), formerly known as Waukesha Electric Systems, and SCE, the ultimate project goal was to demonstrate a smart grid-compatible FCL superconducting transformer that was connected to the grid at a utility host site.

The planned 28 megavolt-ampere (MVA), three-phrase, medium-power FCL transformer (rated for the 69 kV/12.47 kV class) would have been placed within the SCE MacArthur Substation in Irvine, California. The integrated FCL capability would have enabled much-improved fault current handling. Anticipated results from the original planned efforts on cryogenic techniques, high-voltage dielectric materials, bushings, and alternating current (AC) losses in high-temperature superconductors would also have been useful to cable and other fault current limiter projects.

The project's ultimate goal changed significantly due to SPX withdrawing from the project in early 2014. Without a transformer manufacturer to build the planned prototype FCL unit, the plan to build a transformer and demonstrate its operation while connected to the grid had to be abandoned.

In response to a proposal from SuperPower, DOE agreed to continue funding the project with the remaining efforts focused on continuing the necessary development of certain key technologies relevant to significantly improving second-generation, high-temperature, superconducting (2HTS) bonded conductor characteristics and production. Significant improvements in these key technologies were still needed to support a future (beyond this project) fabrication and testing of a prototype superconducting FCL transformer that was not only functional, but that also would potentially be a commercially viable product. The continuing tasks include the following:

- Continued development and enhancements of the conductor bonding technology
- Confirmation of the FCL operation of the design through development and testing of a small-scale winding
- Continued development of 2HTS wire with lower AC losses for use in bonded conductor and testing to measure and validate the bonded conductor's AC losses
- Increasing the length and quality of the bonded conductor that can be produced for use in windings for a full-scale superconducting FCL transformer

This project is ongoing, with project activities currently scheduled to conclude in September 2016. Currently, SuperPower is continuing trials and produced a "good" bonded conductor in March 2015. The team expects to wind the small scale coil to test for AC losses and FCL operation in April 2015. The system to test for the AC losses is in development and should be ready for testing by May 2015. The reel-to-reel testing rig is being completed and should be operational by April 2015. The team produced a significantly longer length conductor, showing improved current carrying performance, and is analyzing the data. Additional key technical results will be provided in the final report upon the project's completion which is expected in December 2016.

Northeast Utilities Service Company — Urban Grid Monitoring and Renewables Integration (32)

NUSCO is in the process of enhancing the grid monitoring instrumentation on one of its secondary area network grids in downtown Boston, Massachusetts, to provide unprecedented visibility into the operation of the grid. This project will use state-of-the-art sensor equipment along with a novel, low-cost approach to monitor current and conductor temperature on individual secondary cables.

AMR meters will be installed for customers who are integrating solar PV. With sensor, smart meter, and SCADA data sent to a repository for analysis, NUSCO expects to greatly improve its understanding of grid status and behavior, allowing for proactive maintenance that improves safety and increases reliability. The visibility gained from this project is also expected to enable increased integration of PV generation and to safely test other inverter-based DER integration into the secondary area network grid.

This project is still in the data analysis phase, but expected benefits include maintenance cost reductions through early identification of potential equipment failures and the potential to reduce emissions through the integration of solar PV and reduced truck rolls enabled by enhanced network monitoring.

NUSCO expects to learn additional lessons and develop best practices upon completion of the data analysis and commissioning phases of the project. The project is expected to conclude at the end of 2015 and the FTR submitted in March 2016.

4.3 SGDP Regional Demonstration Program Observations

The aim of the SGDP projects was to demonstrate new and more cost-effective smart grid technologies, tools, techniques, and system configurations that significantly improve on the ones commonly used today. The regional demonstration subset of the SGDP projects focused on the integration of advanced technologies including power system sensing, communications, analysis, and power flow controls with existing power systems that involved renewable and distributed energy systems and DR programs. These demonstrations were expected to verify smart grid viability, quantify smart grid costs and benefits, and validate new smart grid business models at scales that can be readily replicated across the country. Collectively these projects were expected to demonstrate technologies in all areas of the smart grid including, customer systems, AMI, advanced distribution operations, and advanced transmission operations including key interfaces with ISOs. Eleven of the sixteen projects are complete and FTRs have been received. The remaining five projects have not yet submitted FTRs.

Seven of the eleven completed projects successfully demonstrated AMI and customer technologies. The NUSCO AMR project confirmed that a legacy AMR system can be leveraged to perform AMI functions, potentially deferring capital expenses for AMI until the legacy AMR systems are fully depreciated. Pecan Street created an energy internet and the nation's only research AMI meter network. It also offered incentives to customers to invest in PV, increasing the number of roof-top PV systems from eleven to 200 on its system. Con Edison identified a number of benefits including substantial operational savings for meter reading and analyzed that between $1.1 million and $3.7 million in additional annual income may be available to DR resources as a market participant in the NYISO capacity market. Similar results were experienced by AEP Ohio in terms of meter reading savings and reduced truck rolls from AMI. NRECA deployed various smart grid technologies across 23 participating cooperatives in varying degrees. DR savings of $700,000 annually was reported from one cooperative and a reduction in peak load of 10% to 15% by another. The results of these projects in the AMI and customer technology areas suggest that these smart grid technologies offer benefits that far exceed those of today's legacy systems.

Four of these seven completed projects also demonstrated technologies in the advanced distribution operations area. AEP Ohio with its deployment of its DACR and VVO systems improved reliability, reduced energy consumption by 3%, and demand by 2-3%. Similarly NRECA through its deployment of CVR and smart feeder switching has improved reliability and reported financial savings from advanced voltage control. In addition to deploying 14,000 smart meters, KCP&L integrated its AMI real-time communications with some of its other systems including the customer information system (CIS), distribution management system (DMS), outage management system (OMS), and the DERMS. And LIPA is creating a Smart Grid Corridor by deploying small scale AMI, DA, SA, DR, and customer technologies. Given the size and scope of the project they expect the potential economic, reliability, and environmental benefits to be minimal.

Boeing focused on cyber security technologies by performing a cybersecurity risk-based assessment of PJM's critical network and information systems. Multiple cybersecurity solutions were then deployed across a variety of PJM's systems. All of these are suitable for replication across the electric sector and/or across the energy sector as a whole. With the increasing risk of cyber-attack of the nation's infrastructure, cybersecurity countermeasures are highly valued.

The remaining three completed projects focused on smart grid technologies aimed at the transmission system. CCET demonstrated that the use of synchrophasors, energy storage, and DR can improve wind integration in the ERCOT system. Oncor and NYPA demonstrated DLR technologies and confirmed the presence of real-time capacity above the static rating, in most instances, with up to 44% additional usable capacity made available for transmission system operations. Oncor's project represents the first time that dynamic ratings were automatically incorporated directly into a system operator's economic dispatch tool. A key finding is that DLR can be a cost effective alternative for increasing transmission line capacity when compared to other alternatives such as reconductoring lines or modifying structures.

These projects successfully demonstrated a wide variety of smart grid technologies and qualitatively identified a large number of benefits that were realized. The monetized value of the benefits for only a few was provided. The capital costs for these projects were substantial and no incremental O&M costs were identified. Whether these projects have positive business cases or not or if they are competitive as least cost options is not known. Continued and increasing deployment levels will depend on the degree to which these technologies are cost effective.

The remaining five projects are in various stages of completion. LADWP's focus is on the demonstration of AMI and customer technologies including B2G technologies. Battelle is focusing on the notion of transactive control at the transmission level and is validating more than twenty types of responsive smart grid assets across 5 states in the northwest with eleven utilities.

The remaining three projects are demonstrating technologies in various smart grid areas. SCE is demonstrating numerous smart grid technologies in Irvine, CA including SA, DA, volt/VAr control, phasor measurement units (PMU), in-home devices, and energy storage. The NUSCO urban grid monitoring project is installing sensors in the Boston secondary network grid to provide unprecedented visibility into the operation of the grid. Finally, SuperPower has scaled back its project scope from the development of a 28 MVA, 69/12 kV grid-connected, superconducting FCL transformer to specific research on the associated enabling technologies.

A number of specific lessons learned were identified and are addressed in the SGDP project FTRs. More broadly:

- The acceptance and ultimately the degree to which customers will engage with smart grid technologies needs continued attention. Reliance on manual actions by customers as opposed to "set it and forget it" constructs will limit consumer participation. Also, the segment of the customer population participating with smart grid technologies needs to be increased as many of them today are highly educated, have high income, and are technologically savvy.
- Substantial opportunity may exist in leveraging smart grid technologies by participating as a market participant with Regional Transmission Organizations (RTO) and ISOs.
- Further financial analyses of the results of these projects is needed to determine if they represent positive business cases or are competitive with other least cost options.

The SGDP projects were expected to quantify smart grid costs and benefits; however, this was generally not done. The lack of complete cost/benefit data prevents any meaningful financial analysis from being performed.

4.4 SGDP Energy Storage Project Status

The majority of the energy storage projects are grid-connected demonstrations but four of the projects (Seeo, Aquion, SustainX, and Amber Kinetics) focused their demonstrations on the development of advanced storage technologies or prototypes at the laboratory level. The status of all sixteen projects is presented in Table 4.

Project	FTR Received[7]	FTR Projected
New York State Electric & Gas Corporation	9/14/12	
Pacific Gas & Electric	NR	Mar 2023
Southern California Edison	NR	June 2016
Beacon Power Corporation	NR	Dec 2015
Duke Energy Business Services	NR	Sept 2015
Primus Power Corporation	NR	Mar 2018
Premium Power	NR	April 2018
Seeo Inc.	4/20/15	
SustainX	1/6/15	
Aquion Energy	4/8/13	
Detroit Edison Company	NR	Dec 2015
Ktech	NR	June 2015
Amber Kinetics	NR	Sept 2015
City of Painesville	NR	Jan 2016
East Penn Manufacturing	NR	July 2015
Public Service Co of New Mexico (PNM)	4/8/14	

Table 4 Status of SGDP Energy Storage Projects

4.5 SGDP Energy Storage Project Results

As of the date of this report, five of the sixteen SGDP Energy Storage Projects have completed their field demonstrations and FTRs have been received. The FTRs for these completed projects may be found at www.smartgrid.gov.

[7] Designates projects for which a final, approved FTR has been received. NR indicates that the FTR has not yet been received.

4.5.1 Completed SGDP Energy Storage Projects

New York State Electric & Gas — Seneca Advanced Compressed Air Energy Storage Project (33)

New York State Electric & Gas (NYSEG) planned to develop an advanced compressed air energy storage (CAES) plant with a rated capacity of 150 MW using a 4.5 million cubic foot underground salt cavern in Reading, New York.

During the course of the engineering design, NYSEG discovered that the project economics would be less favorable than originally estimated. Overall project costs would be between $320 million and $370 million greater than the $125.6 million that was originally estimated for the project. The increase in project cost was due to requirements for additional caverns and increased construction costs. Revenue projections decreased due to a capacity factor of “only 10% to 20%,” excess capacity in the NYISO market area, and an increase in natural gas generation (which would displace generation from the CAES plant due to the lower cost of natural gas generation). As a result, NYSEG determined that the economics were no longer favorable, and further development was halted. Although construction was halted, the analysis has resulted in a framework that can be used for assessing future CAES projects.

Seeo, Inc. — Solid State Batteries for Grid-Scale Energy Storage (34)

Seeo, Inc. (Seeo) aimed to demonstrate a large-scale prototype of a solid-state electrolyte lithium ion rechargeable battery for use in smart grid energy storage applications. They particularly wanted to address the needs of community energy storage (CES) systems, which are small (less than 100 kW) systems used in conjunction with PV arrays. In addition, Seeo’s technology is equally applicable for EV energy packs. This was a demonstration of the battery technology itself rather than a demonstration of the integrated operation of the energy storage system with the larger power system.

Seeo initially planned to demonstrate a 25 kWh battery pack, but the field demonstration ultimately comprised a smaller 10 kWh battery pack. This change was made because Seeo determined that a 10 kWh battery would “be a better fit” for the solar PV used during the field demonstration. Unfortunately, the demonstration of the 10 kWh battery pack was not completed because the system was destroyed by a fire that resulted from overvoltage conditions. This issue revealed that, although the battery cell itself did not need to be redesigned, the battery system’s electronics needed to be redesigned to improve the system’s robustness. Such a redesign was beyond the scope and timeline of this project but has since been performed.

Seeo's large-format, 10 ampere-hour cells did achieve over 1,000 charge-discharge cycles. Projections indicate that the large-format cells can likely achieve the target operating life of 3,000 to 5,000 cycles although full demonstration of that would take approximately four to six years. Also, the large-format, 10 ampere-hour cells produced 220 watt-hours per kilogram, which represents at least a 40% improvement in specific energy density when compared to existing large format lithium-ion cells on the market today.

The data required to perform the final data analysis was never compiled due to the thermal event mentioned above that resulted in the loss of Seeo's system; however, Seeo noted several key achievements during the project's limited duration.

Seeo's technology enables batteries with higher energy densities, greater reliability, and lower cost when in full volume production. Seeo's cell technology has been scaled up into large form-factor cells that can be assembled into battery packs sized from a few kWh to over 100 kWh for grid energy storage solutions and PHEVs. With higher energy density, Seeo's present and future technology offers the advantage of more energy for a given weight making the batteries lighter and more compact. The higher energy density also allows for a higher throughput (per kWh) in production and hence lower costs, making the batteries more affordable for Seeo's customers and ultimately consumers.

Energy storage solutions, like Seeo's, offer the benefit of storing energy from renewable energy sources, such as PV arrays that are intermittent in their generation, and using the energy at later times when needed. This offers the opportunity for greater flexibility and reliability in the use of renewable energy, offers further expansion of renewable energy sources, and makes them more economical while reducing greenhouse gas emissions. Energy storage solutions also provide the advantages of a more stable and secure grid by reducing peak demand and providing backup power. Seeo's technology meets this need with a higher energy density technology, enhanced safety characteristics, uniform performance, and longer calendar life regardless of ambient temperature.

The Seeo technology has the potential to lower energy costs for customers by combining renewables and energy storage with the potential lower cost of Seeo's technology. Customers can lower energy bills by storing energy from PV for use during the evening hours, or by charging up the battery during lower off-peak hours for use during peak hours together with PV.

Seeo's production cost target was to achieve a 35% cell cost reduction from the cost of existing lithium-ion batteries. Although this cost target was not achieved during the project period, Seeo is confident that it can be achieved with a high-volume manufacturing set-up and with the improvements in cell energy density.

SustainX — Demonstration of Isothermal Compressed Air Energy Storage to Support Renewable Energy Production (35)

SustainX Inc. (SustainX) developed a modular, megawatt-scale isothermal compressed air energy storage (ICAES) system under the SGDP. The ICAES system uses an electrically driven mechanical system to pressurize air for storage in low-cost pressure vessels, pipelines, or lined-rock caverns. The stored air later expands through the same mechanical system to drive the electric motor as a generator. This was a demonstration of the ICAES technology itself rather than a demonstration of its integrated operation with the larger power system.

SustainX successfully commissioned a 40 kW round-trip ICAES system as a pilot in September 2010 that incorporated and successfully demonstrated key enabling technologies for ICAES of this scale, including novel spray-based heat transfer and an optimized hydraulic drivetrain. Lessons learned from this pilot system were instrumental in developing the commercial-scale prototype. Research, design, and optimization of the 40 kW pilot system composed Phase 1 of the project.

Phase 2 of the demonstration was a 1.5 MW commercial-scale prototype. The 1.5 MW prototype has been operational since September 2013, and early data has already begun to inform future design enhancements. This system incorporates new, enabling technologies developed for this implementation, including techniques for using foam to effect rapid heat transfer and high isothermal efficiencies at faster speeds; new valve technology for low flow and actuation losses; and a new crankshaft-based drivetrain platform that allows for reduced system cost, higher efficiency, and greater future scalability. Now in operation, this system will serve as a building block, allowing for installation of ICAES systems sized to any multiple of this base power.

SustainX has achieved breakthrough cost-effectiveness through the use of proprietary methods for isothermal gas cycling and staged gas expansion implemented using industrially mature, readily available compounds. The ICAES system proved scalable, non-toxic, and cost-effective, making it suitable for renewables firming and other grid applications. SustainX expects that the megawatt-scale ICAES system will be competitive with other storage options based on both its low levelized cost of energy and its qualitative features, such as its nontoxicity, siting flexibility, modularity, and independent scaling of power and storage.

No specific production costs or other financial information was provided.

Aquion Energy, Inc. — Demonstration of Sodium-Ion Battery for Grid Level Applications (36)

In collaboration with Carnegie Mellon University, Aquion Energy, Inc. (Aquion) developed a low-cost, ambient temperature sodium-ion battery. Aquion began by building approximately 4 milliwatt-hour "coin" cells and evolved the design to create approximately 35 watt-hour cells. The larger cells were then combined to form a system of approximately 11 kWh. The system had an energy density of 25 kWh per cubic meter and was meant for medium-to long-duration (greater than 2 hours) charge and discharge cycles. The system approached 95% direct current to direct current efficiency. It has operated for one year with 1,000 cycles and no identifiable system degradation. It is expected to function for more than 10 calendar years and 10,000 cycles, remain non-toxic, and be cost competitive with lead-acid (PbA) batteries. This was a demonstration of the battery technology itself rather than a demonstration of the integrated operation of the energy storage system with the larger power system.

Based on project data, Aquion believes that its production units will have excellent cycle life stability when they are produced. It is currently examining the possibility of introducing a novel, higher-energy-density, composite anode system that will increase the total energy of the battery system by 25% or more. It is also looking to reduce the amount of non-functional material in the actual electrode structures as much as possible. Specifically, Aquion is studying new low-mass content binders. Longer-term design efforts are also under way to reduce the bulk of the packaging and to increase the amount of control of the structural forces used to keep large format battery stacks intact.

No specific production cost data was provided.

Public Service Company of New Mexico — PV Plus Battery for Simultaneous Voltage Smoothing and Peak Shifting (37)

PNM co-located a 0.75 MW energy storage system with a separately installed 0.5 MW solar PV plant on its distribution system, creating a dispatchable distributed generation resource. The PV plant's maximum output generally occurred about two hours before the grid's daily peak; by coupling energy storage with the PV installation, PNM could store energy produced in the mornings for use during system peak hours. This hybrid resource provided simultaneous voltage smoothing and peak shifting through advanced control algorithms. Data collection and analysis produced information for a wide range of benefits, such as the deferral of grid upgrades. The project also yielded modeling tools used to optimize battery system control algorithms and an enhanced understanding of feeders with storage and distributed generation.

Overall, the smoothing battery system appeared to effectively reduce PV output volatility. PNM confirmed that the system's smoothing effects were successful on cloudy days and when the circuit's voltage fluctuated significantly. PNM evaluated the smoothing impacts of utilizing the energy storage system at various capacities. It found that utilizing 10% of the battery system's capacity had little effect on smoothing. However, capacity utilizations of 40% or more had noticeable effects on smoothing.

The PV-plus-battery system successfully shaved the targeted 15% off the feeder peak. However, a reduction of 15% was only attainable when the feeder profile had a sharp predicted peak (i.e., on hot days with temperatures above 92 degrees Fahrenheit). During cooler periods, the load profile was too broad to achieve the 15% reduction target, and the actual feeder peak shaved was less than 10%. The PV-plus-battery system's firming functionality was also demonstrated. Firming production from the battery began at 5:00 a.m., and the battery discharged energy later in the day as needed. However, state-of-charge limits and rate of charge both limited the amount of PV output that could be stored during the morning, especially during the summer.

Overall, the peak-shaving application produced the highest level of individual application benefits based on deferred generation capacity investments and deferred distribution capacity investments. In its analysis, PNM valued the distribution investment deferral at approximately $334,000 and the system electric supply capacity benefit at $177,000. Other benefits included optimized generator operation, reduced CO_2 emissions (600 tons), reduced sulfur dioxide emissions (300 pounds), and reduced nitrous oxide emissions (800 pounds).

4.5.2 SGDP Energy Storage Projects Still in Progress

Eleven of the sixteen SGDP Energy Storage projects have not yet submitted FTRs. When received and accepted, all FTR's will be available at www.smartgrid.gov when the projects are completed.

Pacific Gas and Electric Company — Advanced Underground Compressed Air Energy Storage (38)

Pacific Gas and Electric Company's (PG&E) advanced underground, CAES demonstration project is intended to validate the design, performance, and reliability of a CAES plant rated at approximately 300 MW with up to 10 hours of storage. The CAES demonstration project is scoped to test the suitability of a porous rock formation as the storage reservoir in California and demonstrate the technological improvements in the design of such plants.

This project is composed of three phases. Phase I includes site selection, reservoir testing, preliminary plant design, an environmental assessment, and a competitive solicitation to determine if there are interested and viable parties for plant construction, ownership, and operations/maintenance. Phase I is estimated to last four and a half years. Phase II, which includes obtaining approval to proceed with the construction and commissioning of a full CAES plant, has an estimated six-year duration. Phase III includes operations and monitoring and is expected to occur over two years.

The goals of the project are to verify the technical performance of advanced CAES technology using a porous rock formation as the underground storage reservoir, establish costs and benefits of CAES, and verify system reliability and durability at a scale that can be readily adapted and replicated around the country.

This technology will pressurize an underground cavern or reservoir with air, using an electric motor-driven compressor, during periods of low demand. When demand rises, the reservoir releases air, which the plant heats with natural gas-fired combustors, and then uses to drive turbo-expander units coupled to the generator. Once completed, PG&E expects the plant to provide ramping/regulatory services, reduce greenhouse gas emissions, and improve grid reliability and flexibility.

The project team has comprehensively screened potential reservoirs and sites throughout California to determine a location for a potential CAES facility that would be technically and economically feasible and allow for future development of the facility. Initial screening began with 148 sites; extensive screening narrowed the potential sites to two.

PG&E acquired the rights necessary to conduct the testing (i.e., core drilling and air injection) that was required to determine the technical viability of the sites and to allow for the future construction, operation, and maintenance of a CAES facility. At the final two sites, the project drilled a core well into the reservoir to obtain core samples to be analyzed in the laboratory for specific reservoir properties. Based on the review of the analyses, one site was selected for an air injection test.

The air injection test (to be completed by the end of the second quarter of 2015) will build an air bubble of approximately of 500 million standard cubic feet. A series of injection and withdrawal tests will be conducted to mimic the expected operation of a fully developed project. The test results will then be utilized to help forecast the operational and economic performance of the project.

In conjunction with the test, preliminary engineering and an environmental siting, licensing, and permitting analysis are being completed. The engineering analysis will develop a conceptual design and cost estimate for a fully developed plant. The project information will then be utilized to conduct a Request for Offers (RFO) to determine if third-party developers and operators are interested and qualified to build, own, and operate a CAES facility. The RFO will better inform the costs and benefits to California customers of building and operating the facility.

PG&E's CAES project is ongoing and its FTR is expected to be submitted in March 2023.

Southern California Edison Company — Tehachapi Wind Energy Storage Project (39)

Based at SCE's Monolith Substation in Tehachapi, California, the Tehachapi Wind Energy Storage Project includes a 32 MWh BESS and associated power conversion system (PCS). The PCS is composed of two outdoor power conversion system enclosures each rated for 4 MW/4.5 MVA capacity, designed for connection at 12.5 kV, and capable of four-quadrant operation.

The project will evaluate the performance of the BESS to improve grid performance and assist in the integration of large-scale variable energy resources. SCE is also demonstrating the ability of lithium-ion battery storage to provide nearly instantaneous maximum capacity for supply-side ramp rate control to minimize the need for fossil fuel-powered back-up generation.

SCE has identified 13 operational uses for the BESS. These uses align with the economic, reliability, and environmental benefits that DOE has set for grid-scale energy storage projects, and they help demonstrate the ability of lithium-ion BESS to meet the public benefits goals set out by DOE. Testing of these operational use cases is ongoing and will be discussed in the project's FTR.

This project is ongoing. Installation of a small-scale system, consisting of all full-scale functional components with a scaled-down battery set, is complete, and provides the opportunity for operational testing. In addition, SCE has completed end-to-end testing of software, communications, and data collection components. The final phase of commissioning tested the BESS control strategy in a real-time digital simulator environment. Future project reports will discuss the testing of the 13 operational use cases. Data collection is expected to complete in June 2016 and the FTR submitted at that time.

Beacon Power — 20 MW Flywheel Frequency Regulation Plant (40)

Beacon Power (now a wholly owned subsidiary of Rockland Capital LLC) designed, built, and operates a utility-scale, 20 MW flywheel plant in Humboldt Industrial Park in Hazle Township, Pennsylvania. The Beacon Power technology uses flywheels to recycle energy from the grid in response to changes in demand and grid frequency.

Each Beacon flywheel is designed to provide 100 kW of output and store 25 kWh of energy. Two hundred flywheels connected in parallel provide 20 MW in capacity and can fully respond in less than 4 seconds. When generated power exceeds load, the flywheels store the excess energy. When load increases, the flywheels return the energy to the grid. The flywheel system can respond nearly instantaneously to an ISO's control signal at a rate 100 times faster than traditional generation resources. The system does not burn fuel and has zero direct emissions. The plant can operate at 100% depth of discharge with no energy degradation over time and provide unlimited cycles for most applications. Built with flywheels that last 20 years or more, the mechanical portion of the flywheel system requires virtually no maintenance.

Owned and operated by Hazle Spindle LLC, the plant provides frequency regulation services to the grid operator, PJM. This reduces the overall need for frequency regulation, improves system efficiency, and enables generators elsewhere in PJM to run at more optimum energy output.

Beacon Power was unavailable in June 2014 due to a main breaker trip and again in September 2014 due to a computer communication problem. Nevertheless, since going online, the plant's availability has been near 98%.

PJM uses a performance score metric to measure how accurately a facility is following the regulation signal. The average performance score for the plant since going online is 97%. The average performance score for all resources performing regulation in PJM in 2014 is 80%, so the Hazle Spindle plant is performing well above the average. No cost/benefit data was provided.

Beacon Power's project was field-completed in December 2014 and the plant continues to operate. The FTR is expected to be submitted in December 2015. A project cost/benefit analysis was not provided.

Duke Energy Business Services — Notrees Wind Storage Demonstration Project (41)

Duke Energy Business Services conducted an energy storage project called the Notrees project to evaluate how energy storage that is integrated with wind power can compensate for the inherent variability and intermittency of this renewable power generation resource. Incorporating both existing and new tools, technologies, and techniques, this demonstration project provides valuable information regarding wind energy storage and serves as a model for other entities to adapt and replicate. The energy storage system was designed and constructed using fast-response, advanced lead-acid batteries configured to provide 36 MW output peak power with an energy storage capacity of 24 MWh.

Following commercial operation testing, the project began supplying service to ERCOT via a FRRS pilot program in February 2013. Under the FRRS program, a resource must meet two criteria—it must deploy within sixty cycles of a dispatch instruction or triggering frequency, and it must provide 95%-110% of the obligated capacity during the entire duration of the deployment.

The battery currently participates in the FRRS market on a regular basis, providing 32 MW of FRRS-Up capacity and 30 MW of FRRS-Down capacity. The energy storage system can respond immediately to address frequency deviations and gives the automatic generation control (AGC) system crucial time to correct the problem.

The Notrees project also demonstrated other ancillary services that could be provided to ERCOT including area regulation which follows the AGC signal, electric supply reserve capacity, voltage support, transmission congestion relief, and wind generation grid integration (short duration). The project also demonstrated renewables capacity firming services by simulation.

The project is complete, and the FTR is expected to be submitted in September 2015. A project cost/benefit analysis was not provided.

Primus Power Corporation — Wind Firming EnergyFarm™ Project (42)

Primus Power Corporation (Primus Power) is deploying a 25 MW/75 MWh EnergyFarm™ project, located in the Modesto Irrigation District (MID) in California's central valley. The EnergyFarm™ project consists of an array of 250 kW EnergyPod® flow battery cells, plug-and-play zinc-flow battery modules, and power electronics systems housed inside standard shipping containers. The modular design and operation is currently being field tested at PG&E with support from Sandia National Laboratories and EPRI. The 25 MW EnergyFarm™ project will support MID's efforts to balance increasing amounts of renewable generation and more efficiently manage its fleet of generating assets to meet peak loads. The system will likely be deployed incrementally in multiple substations and provide additional benefits, such as local-area voltage stability and deferral of substation upgrades.

The goals and objectives of this project are to develop, integrate, and demonstrate a low-cost zinc-based flow battery storage system with a footprint consistent with or smaller than competing technologies. Primary and secondary applications are expected to be demonstrated including renewable firming, strategic local peak shaving, automated load shifting, and ancillary services.

Each zinc-flow EnergyCell battery module can store 72 kWh of energy with a discharge time of 3.6 hours (20 kW). The EnergyCell can also discharge at faster or slower rates—7.2 hours at 10 kW or 2.4 hours at 30 kW. The EnergyPod® flow battery cell is an ISO shipping container that houses 14 EnergyCells with a nominal rating of 280 kW direct current (DC).

In 2013, Sandia National Laboratory tested Primus Power's products. This independent testing confirmed the EnergyPod® flow battery cells' ability to provide uniform power at discharge durations ranging from 2 to 7 hours, high roundtrip efficiency, and the ability to switch from charge to discharge in less than 0.5 second. The results of these tests demonstrated that EnergyPod® flow battery cells are technically and economically attractive for a variety of on-grid and off-grid needs, from transmission deferral to renewable integration, distributed peaking, and microgrid operations. The first EnergyPod® flow battery cell was built in the second quarter of 2015. (43)

Primus Power will deliver EnergyPod® flow battery cells to the MID, a 600 MW utility in California's Central Valley. MID is a small balancing area with nearly 30% renewable penetration and the effect that renewables have on their grid is more pronounced than in other, larger grid systems. The utility intends to use 1 MWh EnergyPod® flow battery cells to aid in the integration of renewables into its grid, including a new 25 MW solar facility. The EnergyPod® flow battery cells will reduce the intermittency created by solar on their grid. Installation is expected to occur in the second half 2016.

Results from PG&E's validation testing and analysis, as well as the deployment of the EnergyPod® flow battery cells to the MID, will be included in Primus Power's FTR which is expected to be submitted March 2018.

Premium Power — Distributed Energy Storage System Demonstration (44)

Premium Power and its partners will demonstrate a multi-hour, vanadium redox battery-based energy storage system (ESS). The project is based on Premium Power's containerized 500 kW, 6-hour VNX C-Series ESS, which includes energy storage, power conditioning, system control, and thermal management subsystems. The ESS will be grid-connected with National Grid at two locations in Massachusetts. The project will demonstrate a number of ESS applications, including load shifting, peak shaving, and renewable system integration.

Primary objectives are to demonstrate competitively-priced, multi-megawatt, long-duration advanced batteries for utility grid applications, demonstrate multiple use cases for increasing penetration of renewable generation and other grid applications at a utility customer site and at a substation, and to validate the economic benefits of selling significant amounts of stored energy into multiple ISO/control areas with distinct pricing.

Premium Power's technology will be integrated at two sites using three main components:

- A customized 53-foot standard shipping container access doors, vents, electric and cooling connections, secondary containment and mounting supports, cell-stacks, stack table, tanks, vanadium electrolyte, and thermal and other necessary subsystems.
- A PCS that includes 500 kVA power electronics that meet all required Underwriters Laboratories (UL) and Institute of Electrical and Electronics Engineers (IEEE) standards and certifications.
- Grid interconnection equipment that will connect to National Grid's distribution system through transformers, switchgear and circuit breakers/protective relays, and smart meters. The systems will be dispatched by National Grid's off-site distributed energy control. Both sites will be capable of being dispatched as a single 1 MW resource.

In the National Grid service area, two 500 kW 6-hour ESSs will be installed for an aggregated 1 MW of dispatchable energy storage. One ESS will be integrated into a single 500 kW, 6-hour system installed next to a 605 kW solar PV array in Everett, Massachusetts. Another 500 kW, 6-hour ESS will be interfaced with a 600 kW wind turbine at the Holy Name High School feeder in Worcester, Massachusetts.

Benefit targets from 5% to 25% for peak load reduction have been established for this demonstration for each of the two locations.

This project is still in progress. The ESS technology is completing design in May 2015 and Premium Power is gearing up for manufacturing through 2015. Complete results including cost and benefit information is expected when Premium Power submits the FTR which is expected in April 2018.

DTE Energy Company — Advanced Implementation of Energy Storage Technologies (45)

DTE Energy (formerly the Detroit Edison Company) designed, constructed, and will install an aggregated 1 MW CES system in their service territory on one distribution circuit at the Trinity substation in Michigan to demonstrate the potential of CES systems to strengthen grid reliability. The performance data of the CES devices and control systems under in-service operating conditions will be analyzed and used to identify gaps and facilitate how the devices can be standardized for use across the U.S. The project will also integrate the utility-owned 500 kW PV system to the energy storage device; provide proof-of-concept testing for an integrated, centralized communication system; and test the use of secondary-use EV batteries as CES devices.

This project will install twenty CES units into a distribution circuit that includes a separate 500 kW BESS integrated with an existing 500 kW PV system. The first eighteen CES units are equipped with 25 kW, 50 kWh batteries and are installed on the same circuit as the larger-scale BESS. Two CES units with secondary-use EV batteries will also be installed. As of April 2015, 18 CES units have been installed, and two secondary-use EV CES units have completed testing and are in the installation phase.

A number of applications will be demonstrated using various combinations of the CES units, including those powered from secondary-use EV batteries, and the larger BESS. These applications include load following, peak shaving and time shifting, area regulation (through simulation), voltage support, PQ, DR, and local islanding during outages if the occasion arises.

DTE finalized their test plan in May 2014 and implemented the test process starting in June of that year on a fleet of fourteen CES units. A number of initial technical difficulties were experienced but ultimately resolved allowing testing to proceed. Testing has begun on a number of applications including charge/discharge testing, renewable energy time shifting, and peak shaving, but thus far no specific test results or quantified benefits have been provided. Seven EV battery packs have been delivered, testing is underway, and they are expected to be commissioned in May 2015.

CES testing is ongoing and DTE indicates it is meeting all system operation goals thus far. Further testing will be discussed in the FTR which is expected to be submitted in December 2015.

Ktech Corp — Flow Battery Solution for Smart Grid Renewable Energy Applications (46)

The Ktech project integrated EnerVault's Vault-20 BESS with a Helios dual-axis tracker PV system at an agricultural site in Central Valley, California. The battery is a Fe/Cr redox flow battery rated at 1 MWh and 250 kW. This is the first demonstration of a MW-scale Fe/Cr redox flow battery.

The battery storage system stores the energy generated by the PV system. When needed, the battery delivers power to run an irrigation pump and inject energy back to the grid during peak times to help offset demand. The modularity of the system provides scalability for multi-megawatt deployments. EnerVault plans to begin manufacturing flow battery stacks in its Northern California plant within 12 months of project completion.

The project's primary objective was to combine proven redox flow battery chemistry with a unique, patented design configuration to yield an energy storage system that meets the combined safety, reliability, and cost requirements for distributed energy storage. Some of the specific goals include the ability to operate at grid scale, to maintain rated power for full discharge time, and to be low cost using abundant materials with a target price point in the range of $250/kWh.

Technology development progressed during the project from 15-by-15-centimeter, lab-scale cells, and 20-layer stacks, to a 2.5 kW prototype system, to a 30 kW alpha system, concluding with the 250 kW beta system. The energy storage component of the project is complete, but beta field demonstration is ongoing. Some of the results demonstrated thus far include:

- Full power rating of 250 kW net AC in charge and discharge modes
- Full power, constant discharge of 250 kW net AC over four hours
- Full system energy rating of 1 MWh
- Cycling capability at full power and energy from the original set of cascades
- High degree of cell voltage uniformity throughout the system
- Ability to consistently manufacture precision, high quality stages due to a robust engineering of cells, stages, and cascades
- Thoroughness of factory acceptance testing protocols
- Ability to integrate system components including nine Engineered Cascades power units

No production cost information was provided. Final results will be presented in Ktech's FTR following completion of beta testing which is expected in June 2015.

Amber Kinetics, Inc. — Flywheel Energy Storage Demonstration (47)

Amber Kinetics sought to improve the traditional flywheel energy storage system by achieving engineering innovations in three areas: a low-cost, high-strength rotor; magnetic bearings; and a high-efficiency motor generator to minimize coasting losses. These improvements have resulted in two generations of flywheel systems, which have demonstrated both improved motor-generator performance and validate the high-strength performance of select, low-cost raw materials. This was a demonstration of the improved flywheel technology itself rather than a demonstration of its integrated operation with the larger power system.

The first generation system was developed from a research prototype to a full-scale mechanical flywheel battery, called the Gen-1 prototype. The system had built-in sensing components that could determine frequency and voltage characteristics of the grid and could override the grid signal to manage the amount of electricity discharged. Amber Kinetics designed, built, and tested the Gen-1 flywheel system unit in California. The prototype system stored a total of 5 kWh of energy in a high-strength steel rotor that weighed approximately 750 pounds.

Amber Kinetics is currently developing a Gen-2 flywheel energy storage system designed to source or sink 25 kWh over a 4-hour charge or discharge time. The Gen-2 system will store five times more extractable energy than the Gen-1 prototype in the same volumetric space. An alpha prototype of the Gen-2 system has been designed, built, and tested at the company's outdoor test facility in Alameda, California. Data recorded during initial testing has correlated with predictive models in terms of high motor-efficiency, low bearing drag, and low ancillary power consumption. Preliminary test results on the Gen-2 system indicate the unit is capable of delivering 25 kWh of energy with a DC-to-DC efficiency of greater than 87%. A beta prototype is presently being prepared for further testing and data gathering.

Amber Kinetics performed further work on estimating the commercial competitiveness of energy-focused flywheels for multi-hour storage applications. The estimated cost to produce a Gen 2 system is $100/kWh. Amber Kinetics believes it is possible to further reduce this cost by combining manufacturing processes under one roof, which suggest that energy-focused flywheels could be very competitive with leading chemical batteries when measured on a $/kWh basis.

Final test results will be presented in the Amber Kinetics FTR currently scheduled for September 2015.

City of Painesville, Ohio — Vanadium Redox Battery Demonstration (48)

The initial objective of this demonstration project was to provide metrics and operating experience to enable the 32 MW, coal-fired Painesville Municipal Electric Plant power generating facility to obtain the same daily output requirement in a more efficient manner and with a lower carbon footprint by utilizing the stored energy from a vanadium redox flow battery (VRFB). The project intended to provide metrics to evaluate how to more efficiently level the peak requirements and manage power purchases by strategically incorporating VRFB throughout the power network. Due to funding issues, the project was re-scoped to utilize the VFRB for frequency regulation.

Currently, the Painesville project is approximately halfway to completion. To date, all groundwork and acquisition of necessary technical expertise is complete, along with the battery housing and corresponding electrical service. The drawing package for the battery stacks is 95% complete, and procurement of all battery stack components is in progress. Balance of plant project plans is complete, including vendor selection for critical inverters.

PJM Interconnection personnel confirmed that the battery switching speed of the prototype is more than sufficient to participate in a number of the more profitable energy ancillary services markets. Furthermore, projections suggest that the project will be profitable in the ancillary markets, especially from the frequency regulation service, and should reach break-even in the third operational year. Final results will be presented in the City of Painesville's FTR which is expected to be submitted in January 2016.

East Penn Manufacturing Co — Grid-Scale Energy Storage Demonstration Using UltraBattery® Technology (49)

East Penn Manufacturing has designed and constructed an energy storage facility consisting of an array of UltraBattery® modules integrated in a turnkey BESS, which incorporates a battery monitoring system, a PCS, grid connection and switchgear, and a data management and acquisition system. The UltraBattery® module is a hybrid energy storage device that combines the advantages of an asymmetric ultracapacitor and a lead-acid battery in one cell, thereby taking advantage of the best of both technologies without the need for electronic controls. The BESS is able to provide up to 3 MW of frequency regulation into the PJM market.

The overall BESS consists of a building containing the bulk of the cells (three strings), an outdoor AC/DC power converter and transformer for interconnection, and a portion of the system (one string) packaged in three shipping containers. The building in which the cells are housed includes HVAC to keep the batteries within operating temperature, and is equipped with a fire suppression system.

The BESS demonstrated the following related to its ability to provide ancillary services to the PJM market:

- Provided fast-responding regulation service to PJM's Dynamic Regulation market

- Contributed to a reduction in PJM's overall requirement for regulation while maintaining the same system performance, leading to an overall reduction in system costs for procuring regulation
- Reduced CO_2 and nitrous oxide emissions through offsetting fossil fuel-based generation by using the BESS to provide ancillary services
- Completed demand management tests to demonstrate ability to respond to a Metropolitan Edison request

East Penn Manufacturing verified that the UltraBattery® technology is well suited to provide dynamic frequency regulation service to RTOs like PJM. The ability of the UltraBattery® technology to operate at a partial state of charge allows it to respond to both charge and discharge commands as required to follow the dynamic regulation signal from PJM. In addition, by operating in a partial state of charge region the UltraBattery® module produces very little to no hydrogen during normal operation. This compares favorably to lead acid batteries which are typically maintained at 100% state of charge leading to the generation of hydrogen gas which is an indication of battery degradation.

The accuracy of the frequency regulation system is measured using a performance score calculated hourly by PJM that ranges from 0%–100%. PJM began calculating performance scores in October 2012, based on resources delay, correlation, and precision in responding to the regulation signal. Typical performance scores for the BESS for frequency regulation are in the range of 96%–98%.

The efficiency of the BESS is calculated using the energy in and energy out of the system as measured by a revenue grade meter on the primary side of the BESS transformer. The efficiency calculation also takes into account the change in the state of charge over the course of the measurement period. The average AC-to-AC efficiency of the BESS when providing frequency regulation was calculated to be approximately 82%.

No cost, benefit, or business case information has been provided.

The BESS will continue to operate in the PJM regulation market for the remainder of the project. One of the four strings will be replaced with a different format UltraBattery® module capable of a higher rate of charge and discharge. The new string and final results will be documented in East Penn Manufacturing's FTR which is scheduled to be submitted in July 2015.

4.6 SGDP Energy Storage Program Observations

Energy storage demonstrations are focused on grid-scale applications of energy storage involving a variety of technologies including advanced batteries, flywheels, and underground compressed air energy storage systems. These projects demonstrate a variety of size ranges and system configurations and their impacts on the electric transmission and distribution grid. Some are grid-connected demonstrations, and some focus on the development of storage technologies at the laboratory level. The technical and economic performance of these technologies is being evaluated for a variety of applications including load shifting, ramping control, frequency regulation services, voltage smoothing, distributed energy, and the grid integration of renewable resources such as wind and solar power. Five of the sixteen projects are complete and FTRs have been received. FTRs have not yet been received for the remaining eleven.

The five completed projects had mixed results. Two of the projects did not complete their demonstrations. The NYSEG project intended to develop an advanced CAES plant with a rated capacity of 150 MW using a 4.5 million cubic foot underground salt cavern in Reading, New York. During the course of the engineering design, NYSEG discovered that the project economics would be less favorable than originally estimated (higher than expected costs and lower than expected revenues). The project was terminated in February 2013.

The Seeo project aimed to demonstrate a large-scale prototype of a solid-state electrolyte lithium ion rechargeable battery. This was a demonstration of the battery technology itself rather than a demonstration of the integrated operation of the energy storage system with the larger power system. A 10 kWh battery pack was designed, built, and initial testing was performed but the demonstration was not completed due to a thermal event that resulted in the loss of the battery that was likely caused by a significant overvoltage condition. The data required to perform the final data analysis was never compiled. Seeo determined that a redesign of the battery modules was necessary and decided to end the project. Seeo did note several key achievements during the project's limited duration. Seeo believes their technology enables batteries with higher energy densities, greater reliability, and lower cost when in full volume production.

Two of the three other completed projects successfully demonstrated energy storage systems as prototypes rather than as an integrated operation of the energy storage system with the larger power system. SustainX developed a 1.5 MW commercial scale ICAES system prototype. It has been operational since September 2013, and it has achieved or exceeded all original projections. SustainX expects that the MW-scale ICAES system will be competitive with other storage options in the future but specific production costs or other financial information was not provided. Aquion developed a low-cost, ambient temperature sodium-ion battery made up of a number of 35 watt-hour cells to create a battery system of approximately 11 kWh. The system had an energy density of 25 kWh per cubic meter and was meant for medium-to long-duration (greater than 2 hours) charge and discharge cycles. The system approached 95% DC-to-DC efficiency. It has operated for one year with 1,000 cycles and no identifiable system degradation. It is expected to function for more than 10 calendar years and 10,000 cycles, remain non-toxic, and be cost competitive with PbA batteries, but no production cost data was provided. Neither of these technologies was field deployed.

PNM was the first SGDP storage project to complete a field deployed system demonstration. PNM co-located a 750 kW energy storage system using advanced carbon batteries and UltraBatteries™ with a separately installed 500 kW solar PV plant, creating a dispatchable DER. This hybrid resource provided simultaneous smoothing and peak shifting through advanced control algorithms. Overall, the smoothing battery system appeared to effectively reduce the effects of PV output volatility. In peak shifting mode the system shaved the targeted 15% off the feeder peak. Firming and arbitrage applications were also successfully demonstrated. PNM identified substantial benefits but did not provide any financial analysis regarding its business case.

Results thus far for the energy storage projects are limited given that two were not completed and two were prototypes and not field deployed. The PNM project is encouraging from a performance standpoint given its success in demonstrating both peak shifting and peak shaving capabilities of energy storage. The economics still need to be evaluated to determine if its approach is cost effective.

The remaining eleven projects are in various stages of completion. Eight of the projects are demonstrating a variety of battery based energy storage technologies. Two are demonstrating flywheel technologies, and one is demonstrating a CAES technology.

The eight battery-based energy storage projects are using various types of battery technologies in conjunction with power conversion systems to demonstrate integrated operations with the larger power grid.

- Ktech is developing a 1 MWh, 250 kW, energy storage system using a Fe/Cr redox flow battery to be used in support of a 180 kW PV system agricultural site in Central Valley, California. Testing of the flow battery appears to be successful.

- East Penn is demonstrating an UltraBattery® module for providing ancillary services with PJM. The system is currently providing frequency regulation services up to 3 MW to PJM and will continue to do so for the remainder of the project. The UltraBattery® technology is also deployed at the completed PNM project discussed previously.

- Duke is demonstrating PbA batteries and inverters configured to provide 36 MW with an energy storage capacity of 24 MWh. The system currently participates in the ERCOT FRRS market on a regular basis, providing 32 MW of FRRS-Up capacity and 30 MW of FRRS-Down capacity. Duke plans to demonstrate an additional eight operational use cases in the future.

- DTE is deploying 20 CES battery-based units totaling 1 MW of capacity on its distribution system. Two of the 20 CES units will utilize secondary-use automotive battery units. The CES units will be integrated with its existing 500 kW solar system and 500 kW BESS. A number of applications will be demonstrated using various combinations of the CES units, including those powered from secondary-use EV batteries, and the larger BESS. These applications include load following, peak shaving and time shifting, area regulation (through simulation), voltage support, PQ, DR, and local islanding during outages if the occasion arises. The CES concept represents a possible new dimension in distribution system architecture. The results from the DTE demonstration will help determine whether this concept will flourish. Its synergy with EVs provides added appeal.

- City of Painesville plans to demonstrate a 1.16 MW VRFB system, optimized to perform frequency regulation services at PJM. It is unclear whether the City of Painesville's demonstration will continue due to lack of funding. The project is approximately 50% complete. Other operational use cases are planned for demonstration if the project continues.

- SCE's Tehachapi Wind Energy Storage Project is expected to demonstrate multiple applications of grid-scale energy storage using a 32 MWh lithium ion battery system connected to SCE's 12 kV system. Installation of a small-scale system, consisting of all full-scale functional components with a scaled-down battery set, is complete, and provides the opportunity for operational testing.

- Primus Power is deploying an array of 25 MW energy storage systems using 250 kW EnergyPod® flow battery cells made up of plug-and-play zinc-flow battery modules and power electronics systems housed inside standard shipping containers. Sandia testing of the EnergyPod® flow battery cells was done in 2013. PG&E validation testing is in progress and expected to conclude in June 2015. A number of storage applications are expected to be demonstrated including renewable firming, local peak shaving, automated load shifting, and ancillary services.

- Premium Power will be demonstrating a VRFB energy storage system connected at two locations with National Grid in Massachusetts. Two 500 kW 6-hour BESSs will be installed for an aggregated 1 MW of dispatchable energy storage. One will be integrated with a 605 kW solar PV array and one will be interfaced with a 600 kW wind turbine. The project will demonstrate a number of ESS applications, including load shifting, peak shaving, and renewable system integration.

Two of the projects still in progress are demonstrating flywheel technologies. Amber Kinetics is developing a multi-hour 25 kWh commercial flywheel design. Preliminary test results on the unit indicate it is capable of delivering 25 kWh of energy with a DC-to-DC efficiency of greater than 87%. Expected cost to produce it is $100/kWh. This would make this flywheel design competitive with leading chemical batteries when measured on a $/kWh basis. Beacon has developed a utility-scale, 20 MW flywheel plant utilizing 200 Beacon flywheels each rated at 100 kW connected in parallel. The plant is operating with an availability of ~98% since going on line and is providing regulating services to PJM.

The final project still in progress is PGE's advanced underground CAES demonstration project which uses a saline porous rock formation as the storage reservoir rather than salt domes as is traditionally done. The capacity of the system is planned for 300 MW with 10 hours of storage. The project is not scheduled to complete until 2023.

Economical energy storage is the missing ingredient of a truly modern electric grid. Although many of the energy storage projects are not yet complete and FTRs are not yet received, preliminary results are promising. A variety of new battery designs is being demonstrated—some in the laboratory and some of the more mature designs in grid-connected mode. Final results should provide new guidance for battery selection based on the desired application, technical specifications, and cost. The performance of flywheel technologies is also promising and if cost competitive with batteries may provide another practical alternative for energy storage. The future for CAES is not clear given the economic findings at NYSEG; however, SustainX's successful isothermal CAES prototype is encouraging. Results from the PGE project should shed new light on CAES.

A number of specific lessons learned were identified and are included in the PSARs. More broadly, the learning curve for the development and commercialization of batteries was found to be steep, especially in terms of the transition from a laboratory environment to a large-scale commercial environment. Also, extensive front end analysis and planning is needed on large projects, to ensure capital and O&M costs and expected revenues, particularly those that depend on wholesale markets, are accurately forecasted and monitored through each step of the design, procurement, and construction phases to ensure the project remains cost effective.

5. Topical Reports

The RDSI and SGDP projects were evaluated on a project-by-project basis as discussed previously. This program work laid the framing foundation to establish the business case for fostering the development of the smart grid. In order to structure a discussion of the business case arguments rooted in analysis of the RDSI, SGDP, and SGIG programs, further analysis was segmented into the following topical areas:

- Dynamic Line Rating Systems for Transmission Lines
- National Assessment of Conservation Voltage Reduction
- Microgrid Demonstrations
- Distributed Energy Resource Integration in a Modern Grid
- Smart Grid Communications: Laying the Foundations for Transactive Energy
- Analysis of Smart Grid Business Case Regulatory Filings

Topical reports (TR) were developed for each of these topics. Each TR is incorporated in this report fully by reference. For the sake of producing tractable and targeted documents, these topical reports also exist as standalone reports.

When published, topical reports can be found at www.smartgrid.gov.

5.1 Topical Report Results

The content of the stand-alone TRs are fully incorporated in this report by reference, but high level summaries of the content of each are summarized below:

5.1.1 Dynamic Line Rating Systems for Transmission Lines (50)

This TR evaluated the results of the following two SGDP projects from the perspective of the dynamic line rating (DLR) topic:

- NYPA
- Oncor

The NYPA and Oncor demonstrated DLR technologies to increase the efficient use of the existing transmission network, mitigate transmission congestion, and develop best practices for applying DLR systems. Both demonstration projects confirmed the presence of real-time capacity above the static rating, in most instances, with up to 44% additional usable capacity made available for system operations. NYPA worked with EPRI using technologies and approaches that EPRI developed, while Oncor deployed Nexans' commercially available conductor tension-monitoring CAT-1 System. Key outcomes of the two SGDP projects include NYPA's assessment of the benefits and disadvantages of DLR technologies and Oncor's demonstration that dynamic ratings can be automatically applied in real-time system operations. The projects revealed opportunities to enhance future DLR deployments by ensuring the reliability of DLR data, preemptively addressing cybersecurity concerns, integrating dynamic ratings into system operations, and verifying the financial benefits of DLR systems.

A key finding is that DLR can be a cost effective alternative for increasing transmission line capacity when compared to other alternatives such as reconductoring lines or modifying structures.

5.1.2 National Assessment of Conservation Voltage Reduction (51)

CVR reduces distribution voltages to the lowest possible level during both peak and off-peak periods. This reduction in voltage reduces energy consumption (kWh), system demand (kW), and system losses while maintaining consumer voltages within required operating limits.

Initial analysis indicates that most utilities are still in the pilot project stage when it comes to exploring the potential of CVR. Of the 41 CVR projects reviewed, 26 were pilot projects (more than 60%), and 15 were system deployments. Of the 26 pilot projects, most were being done by investor-owned utilities (IOU). Of the 15 system deployments, over 50% were by IOUs and the remainder was evenly split between cooperatives and municipal utilities.

For the 30 utilities reporting CVR metrics, the average energy savings was 1.84% and the average reduction in peak load was 2.51%. Although the sample sizes are small and not statistically representative of the utility group as a whole, they suggest that CVR can be a highly effective tool for reducing energy costs and lowering demand.

In general, performance of cost benefit analyses for CVR is difficult because minimal financial data is available. A few of the 41 utility CVR projects reviewed; however, did provide documented and verified cost data. For projects where cost data was available, the levelized cost of energy (LCOE) ranged from $0.005/kWh to $0.03/kWh. This range of LCOE compares favorably to the cost of other sources of energy. It is lower in cost than any supply-side option including renewables, and compares favorably to demand-side EE options.

Various technical, regulatory, and utility business model issues complicate the path forward for full CVR deployment. Regulatory treatment of CVR is the most significant factor affecting utility adoption of CVR as the costs are borne by the utility while the customers see the benefits of CVR. The analysis of the business case for CVR focuses primarily on the on the regulatory barriers to CVR deployment and approaches that can be used to overcome these barriers. For example, the analysis explored for this TR found that CVR could be classified as EE from a regulatory perspective, thus allowing CVR technologies to be counted towards mandatory energy savings technologies.

These CVR-related regulatory approaches are being handled in an *ad hoc* manner by various stakeholders across the country, and the goal for this TR was to provide a guide to successful regulatory treatments that could be used to encourage CVR deployment by utilities. The analysis for this report included:

- Descriptions of the various technologies that can be used in the deployment of CVR
- Analysis of the regulatory barriers to widespread deployment of CVR
- Discussion of a variety of regulatory approaches that can be used to overcome these barriers
- Case studies that illustrate successful regulatory solutions that can promote CVR adoption

5.1.3 Microgrid Demonstrations (52)

This TR evaluated the results of the following 4 RDSI/SGDP projects from the perspective of the Microgrid Demonstration topic.

- Chevron Energy Solutions Santa Rita Jail CERTS Microgrid (RDSI)
- Illinois Institute of Technology Perfect Power Demonstration (RDSI)
- San Diego Gas and Electric Borrego Springs Microgrid (RDSI)
- Portland General Electric Salem Microgrid (SGDP), part of the Battelle Memorial Institute project

The technical viability of microgrids was demonstrated by all four microgrid projects. By operating in island mode, all four projects demonstrated that a microgrid can deliver substantial value in terms of reliability and security to the customers within the microgrid footprint.

Two of the projects (SRJ and IIT) are CBMs which are "behind-the-meter" systems where all the microgrid assets are owned by the consumer. These projects operated as full time microgrids and demonstrated the ability to optimize their microgrid resources to generate benefits and economic value. Both projects also demonstrated the ability to integrate renewable resources into their microgrid footprints. These projects were generally more sophisticated in terms of operational capabilities that the other two, which are owned and operated by the utility (UDMs).

Borrego Springs and Salem both focused on improving reliability and resiliency for a specific set of customers. Their microgrids are operated manually when needed to maintain power to their customers and therefore represent more of a back-up system than a microgrid operating full time to optimize the resources within its footprint.

All these projects generated some specific benefits although in a number of cases, some of them were not quantified. Additionally, the capital costs did not include the cost of legacy resources that were preexisting and in some cases annual operational and maintenance costs were not provided. The cost and benefit information provided suggest that microgrids may not have a positive business case except in special cases, such as:

- Large portion of DER portfolio requirements are pre-existing
- Opportunity exists to defer large capital investments
- Cost of utility supplied energy is very high
- Significant production or investment tax credits exist that apply to the DER portfolio
- A method is created for valuing (monetizing) increased resiliency and reliability

Energy storage systems and the MMC are fundamental to successful microgrid operations. These systems are needed to integrate diverse DER portfolios and optimize performance. Energy storage is needed to assist in transient response and transitioning to island mode of operation. The MMC is needed to coordinate and dispatch the microgrid DER portfolio to meet microgrid objectives.

5.1.4 Distributed Energy Resource Integration in a Modern Grid (53)

DERs are devices that supply electricity and are connected to the electric system at the distribution level. DER may exist either on the utility's primary distribution system or "behind the meter" on customer premises. They utilize a variety of renewable and fossil fuel-based energy inputs; electricity storage devices and DR resources can also be classified as DER. For the existing U.S. grid to be fully modernized, it must be capable of integrating and utilizing the full range of benefits that DER can contribute.

This TR evaluated the results of the following six RDSI/SGDP projects from the perspective of DER integration:

- Con Edison — Secure Interoperable Open Smart Grid Demonstration in NY and NJ
- Con Edison — Interoperability of DR Resources
- SCE — Irvine Smart Grid Demonstration
- CCET — Technology Solutions for Wind Integration in ERCOT
- Pecan Street Inc.— Energy Internet Demonstration
- Hawaii Natural Energy Institute — Maui Smart Grid Demonstration Project

These projects adopted multiple DER integration approaches. Utility-owned assets can be monitored and managed using control platforms. Customer-sited DER can be more difficult to integrate, since the utility often does not own or directly control these assets. The projects demonstrated several ways to integrate customer-sited DER, including DER visualization platforms, equipment that allows the utility to control DER load through DR signals, and supporting technologies that allow customers to better control their DER, such as EMS, IHDs, web portals, and devices that enable DR. DER can complement one another when multiple types of DER are integrated, such as intermittent and variable DER integrated with energy storage. This is especially valuable when DER include a mix of utility-owned and customer-sited assets.

All six of the projects demonstrated renewable DER, particularly distributed solar PV and small wind. These resources were integrated with other DER, such as EVs and energy storage, and with supporting systems, programs, and technologies. Some of the key findings reported include:

- PV systems can significantly affect homes' load profiles and can successfully export energy to the grid. In some cases, more than 50% of the energy that PV systems produce is exported.
- CCET analyzed several PQ parameters, including total harmonic distortion of voltage (THDv), total harmonic distortion of current (THDi), and voltage at the distribution level. CCET found that THDv peaked at 4.12%, which satisfies the IEEE Standard 519 requirement that THDv should remain under 5%. Measurements of THDi indicated that higher levels of harmonic distortions might exist on distribution circuits that feed high concentrations of homes with solar PV, compared to those serving homes with little or no PV. (21) This may be an anomaly due to the measurement method used for THDi. Further investigation is needed to determine the impact of this THDi measurement.

- One project determined that west-facing solar PV panels, rather than south-facing solar PV panels, better align with peak demand and are therefore more cost-effective.
- EVs can be integrated with energy storage to reduce their impact on the grid and to enable DR and ancillary service applications for EVs.
- Plug-in EV charging points, in conjunction with BESS, can decrease peak demand. EV charging points can also respond to DR signals to curtail EV charging, when needed.
- While EV battery capacity can provide frequency regulation ancillary services to the grid, the price of doing so is cost prohibitive in ERCOT. Depending on the rules of different ancillary service markets, this application could be profitable elsewhere.
- Several projects concluded that energy storage could complement variable DER, such as solar PV or EVs. Energy storage can reduce peak demand or act as DR or ancillary service resources. However, several economic challenges remain to be resolved before energy storage can be widely profitable. Many of these challenges can be overcome as technology improvements continue to reduce costs of storage technologies.
- One project examined the economic impacts of using a 1 MW BESS to shift peak electricity usage. Doing so would result in a total gross benefit of $3,451,100, but the costs of the BESS would result in a modest net benefit of $491,200. It determined that utilities are not likely to make this investment in ERCOT unless BESS costs decrease.
- BESS was found to be effective for load management, as it smooths variations in loads and renewable energy output. The BESS also demonstrated the ability to both provide regulation and shift times of demand on the generators.

Platforms and other utility systems were developed by several of the projects to monitor and coordinate DER and distribution grid conditions such as voltage monitoring. One project developed a platform for coordinating DR resources, which resulted in significant net annual value and although it was used to coordinate DR resources, a similar architecture could be used to aggregate and coordinate DER. Customer-facing technologies, such as IHDs and programmable communicating thermostats, can also help facilitate DER integration by simplifying or automating the decisions that customers with DER must make, providing information about current electricity prices and communicating DR signals.

5.1.5 Smart Grid Communications: Laying the Foundations for Transactive Energy (55)

This TR examines the communications technologies that enable key smart grid functions, particularly an emerging concept called transactive energy (TE). It highlights the communications and TE efforts of several projects conducted under the SGDP and RDSI program.

The definition of TE is still evolving. This TR adopts the definition of TE that the GridWise Architecture Council (GWAC) developed in its *Transactive Energy Framework* document. According to the GWAC, TE refers to techniques to manage the generation, consumption, and flow of electric power within the grid through economic or market-based constructs, while considering grid reliability constraints. (55)

The energy industry is headed toward increased DER penetration, which will force utilities to allow real-time energy market participation to all generators. Communications technologies will help utilities not only meet smart grid data challenges but also manage real-time participation from all players in the energy delivery model. Communications technologies are essential to enabling TE markets.

TE is predicated on a utility's communications infrastructure. Since the utility's role in a TE system has not been fully determined, the corresponding communications requirements are not certain. However, utilities will certainly require enhanced communications with customers, DR resources, and/or aggregators, and other DER. Utilities will also need to increase coordination with system operators or other entities that operate energy markets to determine the value of energy transactions. The roles of other energy market participants will also change as transactive markets emerge.

Although relatively few utilities are actively planning for a TE future, many are implementing advanced communications infrastructures that will help strategically position them for the transition to transactive markets. Most utilities select communications technologies based on the smart grid functions that they want to achieve, since these functions often dictate the bandwidth, latency, reliability, and security that will be required. The utility's legacy communications infrastructure, the cost of new technologies, vendor relationships, and interoperability considerations also play a role in a utility's communications-related decisions.

A number of SGDP and RDSI program recipients have implemented advanced communications technologies in their projects:

- SCE — 4G LTE cellular and radio
- KCP&L — Fiber optic, plain old telephone service (POTS), radio, Wi-Fi
- Con Edison — 4G LTE cellular, fiber optic, PLC, radio, virtual private network (VPN)
- Battelle Memorial Institute — Fiber optic, PLC
- AEP Ohio — 3G cellular

In many cases, utilities are likely to evolve their existing communications networks to progress toward TE, leveraging the technologies that are already at their disposal. Some utilities are using pilot projects to explore how TE concepts might come to fruition. Other utilities believe that existing communications infrastructures can be leveraged for TE with few modifications. Some have emphasized the need for flexibility in an uncertain future.

Other utilities anticipate that the communications needs of a TE system can likely be met with existing technologies, particularly highly reliable and very low-latency internet connections. Additionally, devices such as building management systems and energy management systems, which coordinate and automate customers' energy use, may be keys to enabling TE.

Ultimately, the need for transactive markets may hinge on the particular needs of the utility's control area. For instance, markets with a great need for DR resources could be more likely to adopt TE. Multiple utilities have expressed that market regulators may have significant influence over whether TE markets come to fruition because some public utilities commissions are hesitant to change rate structures, which may impede the emergence of TE. In other areas, such as California, Hawaii, and New York, state regulators are actively promoting TE markets and are putting pressure on utilities to prepare for the transition.

A lack of standards may be the most significant barrier to ensuring cybersecurity for TE systems. It is difficult, if not impossible, to ensure cybersecurity without working to an accepted standard. A lack of standards can make communications challenging and perhaps represents the biggest challenge to advanced smart grid applications, including TE.

The protection of customers' privacy has always been a concern for utilities, but the emergence of new smart grid applications, particularly TE, makes this issue even more critical. As increased intelligence is added to the grid, customers are becoming increasingly concerned about issues related to consumer data access and the privacy of consumer energy consumption data. Consumers must feel confident that their data is secure and will be protected and treated responsibly, so stakeholders from across the electric utility industry are working to address these concerns.

Key concepts of TE were demonstrated through the SGDP and RDSI program projects. AEP Ohio demonstrated the ability to communicate real-time prices to customers. Battelle demonstrated transactive control of a diverse portfolio of resources and is expected to provide additional insights when the project is completed. Issues of standards, interoperability, cybersecurity, and customer data privacy remain ongoing concerns for any smart grid communications deployment, and a number of technology, business, and regulatory gaps must be addressed before TE can fully support transactive markets. The definition of TE continues to evolve, but many utilities are already preparing for a future in which TE transforms the grid.

5.1.6 Analysis of Smart Grid Business Case Regulatory Filings (56)

This TR reviews available smart grid business case filings by utilities to public utility commissions (PUCs). The goal of the review was to improve DOE's understanding of the costs and benefits being considered by PUCs for smart grid investments.

Twenty three filings were reviewed with the majority from SGIG recipients. Based on these reviews, four major benefit categories were identified—metering, distribution, transmission, and DR. Specific benefits varied widely based on the project's scope and strategy. Six common cost categories were also identified and included equipment, IT, labor, PM, marketing, and maintenance. Cost recovery methods also varied.

A common concern of the PUCs was how to validate the costs and benefits claimed in each case. PUCs also viewed AMI as a foundational technology for other smart grid technologies and applications.

7. Summary

Some RDSI and SGDP projects remain to be completed, but the results submitted to date are generally encouraging from a performance perspective and validate many of the smart grid concepts developed earlier. Most have been successful at achieving project goals, but a few have not. Many lessons learned have been catalogued from both in the FTRs and will be of great value to future decision making. These experiences will also enable similar future projects avoid costly mistakes and also provide guidance for success during their design, construction, and operating phases.

On the other hand, results related to the value proposition for many of the projects are lacking. Without considering capital costs, O&M costs, and the quantification of all benefits it is not possible to determine the value of the projects from a cost versus benefit perspective. Additionally, in most cases, it is not possible from the results, to determine if these projects are cost competitive with other solutions from a least cost perspective. Furthermore, as most of the projects where first-of-a-kind or pioneer demonstrations, the capital and O&M costs associated with these technologies are most likely higher than their equilibrium value once these technologies mature. A definitive cost-benefit analysis cannot be undertaken at this time.

Change management and project management programs were broad areas identified by a number of projects that need improvement. Increased emphasis on both could improve the outcomes of future projects. For example, many projects under estimated the effort needed to conduct a change management program to ensure all stakeholders were involved and aligned with project goals and impacts. This includes all affected departments at the utility, customers, regulators, and vendors. The change management program needs a senior leader and should include continual communications, training and education, and outreach to all affected parties. Stakeholders should be given the opportunity to provide feedback—both positive and negative—so that in-process corrections can be made. A performance feedback process can be helpful in supporting the change management process. (57)

From a project management perspective, a detailed initial scope and conceptual design is needed. Both should be updated as the project progresses and shared with all stakeholders. Project roles and responsibilities should be clearly defined. Use case development can be helpful in the early phases to identify stakeholders and impacts, particularly for projects that will impact multiple stakeholder groups. Project risks should be identified and actions to mitigate them put in place. Capital costs, expected O&M costs, and the forecasted value of revenues and benefits should be constantly monitored to ensure they remain within forecasts. Key personnel should be thoroughly trained on a periodic basis. Communication of project progress should be made to all stakeholders to ensure alignment of all parties is maintained.

The SGDP and RDSI program will generate a great deal of valuable experiences and information. When completed, these results will move the smart grid forward by providing multiple insights in the areas of planning, regulatory proceedings, engineering, and operations for the next generation of smart grid technologies.

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