PUGET SOUND ENERGY

2014 SMART GRID TECHNOLOGY REPORT

September 1, 2014
Filed pursuant to WAC 480-100-505

Contents

Appendices

Cover images (clockwise from left): Wild Horse wind and solar farm, interior of a grid scale battery (image courtesy of RES Americas), PSE's Colin Barnes testing an AMI meter.

Executive Summary

When Puget Sound Energy (PSE) began implementing Automated Meter Reading (AMR) in 1998, few were talking about a "smart grid." During that time, PSE recognized that AMR technology would improve the way we operated and deliver greater value to our customers.

Similarly, when PSE began building its automated transmission system over three decades ago, the company was driven by the need for enhanced real-time monitoring and system visibility – both for our operators as well as improved reliability. Today, this self-healing transmission system is considered a smart grid component.

Over the years, other "smart" components have been implemented, driven by objectives to improve service, reliability and efficiency; enhance safe operations; and support customers in managing their energy.

PSE is actively engaged in several projects that improve system reliability and provide more information and choice to customers.

For example:

- Our automated meters collect energy usage information that enables customers to check and manage their daily energy usage via the Internet;
- PSE has more than 2,000 residential customers with grid-connected solar and wind systems who generate their own power and supply excess energy back to the grid;
- We operate automated transmission and distribution (T&D) systems to improve service reliability; and
- Our new or upgraded back-end information systems are building the foundation for smart grid enablement and making a major improvement in data reliability and transport.

The smart grid future promises the ongoing integration of new and improved technologies that enable data and information to flow securely to and from different end points and applications – from energy generation through the T&D system, to the meter, and into the customer's home or business. In concept, this "system of systems" will be efficient, cost-effective, and will replace or integrate multiple stand-alone systems. It will also be more streamlined and enable data access for multiple uses across the organization. These new technologies will enhance the customer experience through system reliability improvements as well as customer-facing energy management tools. Operationally, PSE will work to improve customer service and safety by enabling advanced monitoring, modeling, control, and automation of the T&D system.

Throughout the United States, each energy company is migrating to this future in a different way. At PSE, our smart grid vision and implementation of smart grid technologies continue to evolve. With our recent integrated implementation of our new Customer Information System (CIS), Outage management System (OMS) and Geospatial Information System (GIS) systems, and completion of significant enhancements to our Energy Management Systems (EMS), PSE is several steps closer to the above promises.

Our future approach continues to focus on building upon and leveraging our existing investments and experience in a careful, thoughtful manner, while taking into account customer value and security of the systems at each step of the way. It is through this strategy that PSE continues on the path toward a smarter energy future.

PSE has been working to integrate key foundational information technology (IT) systems to enable smart grid capabilities. For example, PSE completed the rollout of its modernized CIS, OMS, and GIS. We continue to upgrade the data transport capability of our operations network to better manage the customer experience from billing and service interactions to response times when outages occur. With these systems, PSE has built the foundation to explore new applications like Conservation Voltage Reduction and remote disconnects/reconnects via smart meters with two-way communications for electric customers who change residences. Moreover, these systems will have the capability to communicate specific information to customers through a variety of mediums like web, mobile devices and in-home displays.

Because the smart grid touches almost every part of the company – technology, infrastructure, customers, workforce, and operational processes – ongoing implementation will be necessarily phased over time. Some investments will be made to replace systems that are outdated or at the end of their useful life. The replacement systems will come equipped with smart grid functionalities as a “standard,” much the way the personal computer one buys today has significantly greater functionality than the computer purchased five years ago. Other investments will be made in a more targeted manner to develop specific smart grid functions where there are benefits to do so. Because implementation will necessarily be an evolution, PSE will continue to give consideration throughout the process to potential future upgrades or replacements, compatibility across systems, employee training and customer education.

Experience shows that phased deployment and careful and ongoing selection of appropriate technologies facilitate success. This means implementing technologies that are reliable (when the technology matures beyond adoption by visionaries or early adopters), cost-effective and able to deliver stable, proven processes for PSE and our customers. It also means engaging our customers and soliciting feedback as we develop our implementation plans.

Wisely selecting and funding smart grid-enabling technologies, and then piloting them with PSE customers and employees to ensure both acceptance and usability, provides for a well-architected and systematic advance into smart grid deployment that both minimizes risk and is sensitive to the impact on customers and energy rate structures.

Over the next 10 years, PSE will continue to:

- Work with customers to develop easy-to-use energy management capabilities and reporting tools/information, and general application of technologies;
- Support customer energy needs/desires, e.g., electric vehicles, customer-owned power generation;
- Evaluate and selectively deploy two-way automated metering technology, expanding the operations network into our distribution system over a new AMI network;
- Evaluate and selectively deploy self-healing and automated rerouting of power to improve electric system reliability;
- Evaluate energy storage technologies and deploy grid-scale energy storage pilot projects;
- Upgrade and replace aging infrastructure as needed – for IT networks, back-end information systems, and T&D systems – with consideration to implementing a smarter grid;
- Build out its operations network and implement additional security and reliability for operations data transport (as needed); and
- Evaluate and selectively deploy other customer energy management pilots/programs.

There’s no question that a smarter grid can bring many benefits to both utilities and customers. A smarter grid enhances two of PSE’s core objectives: maintaining high system reliability and efficiency, and empowering customers with the ability to manage their energy efficiently. The bottom line: Getting the PSE smart grid right will benefit our economy, our environment and our customers for years to come.

Introduction

Smart grid refers to an electricity supply chain that employs modern technology to enhance and automate monitoring, analysis, control and communications capabilities along the entire grid. Smart grid technologies can impact the electricity delivery chain from a power generating facility all the way to the end-use application of electrical energy inside a residence or place of business. The ultimate goals of smart grid are to enable utilities to offer more reliable and efficient energy service, and to provide customers with more control over their energy usage.

This report, filed in compliance with WAC 480-100-505, is the biennial follow-up to Puget Sound Energy's 2010 and 2012 Smart Grid Technology Reports. It updates PSE's plan for achieving a smarter system that benefits our customers and our utility operations.

This report is divided into the following sections:

- Background – a working definition and vision of smart grid, customer and utility benefits, lessons learned, and regional considerations;
- Review of PSE's Smart Grid Initiatives – an overview of PSE's decades-long experience with implementing smart grid components, as well as a progress report on 2013-2014 proposed activities;
- PSE's Current Approach – PSE's strategy for and approach to implementing smart grid;
- PSE's Implementation Plan – PSE's next two-year implementation plan and a 10-year roadmap for further developing a smart system;
- Glossary – acronyms and terms defined;
- Appendices – additional details reflecting PSE's smart grid technology initiatives consistent with the Commission's regulatory requirements.

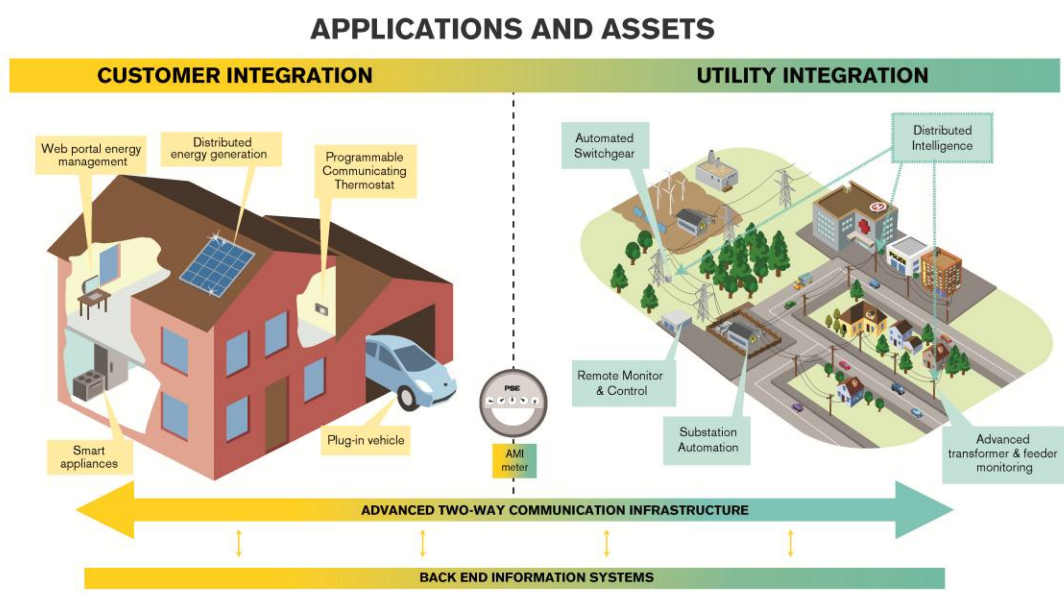
Background

The electric grid has been called one of the most complex machines in the world. It is at the heart of the evolving national movement toward a smart grid. To this end, consider an electric grid that is supported by a safe and secure IT system; that is more reliable and efficient through automated monitoring, control and self-healing capabilities; that provides customers with better information, control and automation to manage their energy use; that engages customers with their utility in managing the overall grid through demand response or critical peak pricing programs; and that supports the adoption of new consumer-driven technologies such as renewable energy generation and electric vehicles.

This is the vision of smart grid: a system that delivers value to its stakeholders through system capability optimization and energy utilization. From an operational perspective, the above depiction can be broken down into three major parts:

- The back-end information systems. Also known as smart grid enablers, these are comprised of major information and control systems, including the Customer Information System (CIS), Meter Data Management System (MDMS), Outage Management System (OMS), Energy Management System (EMS), Distribution Management System (DMS), and Geospatial Information System (GIS).
- The communication infrastructure carries data and information between the back-end information systems and devices located either at the customer's premise (e.g., meters, energy management systems, home automation networks) or at locations in the utility's T&D system infrastructure (e.g., substations, switches, capacitors).
- Applications, including those directed to customer use, such as devices that provide energy information, manage energy use (e.g., demand response, electric vehicles), or enable distributed energy generation. Other applications manage the utility's assets, such as devices located at substations, switches, and capacitors.

Figure 1: Illustration of Potential Smart Grid Applications and Assets



The above illustration (Figure 1) displays some of the potential aspects of a smart grid, including customer and utility applications and assets, two-way communication infrastructure and back-end information systems. These aspects are all expected to benefit both customers and utility operations. These communication and control systems provide added capabilities, efficiency and flexibility to the electric grid. While there are many established and emerging smart grid technologies, there is still much debate around the world about how to achieve a smart grid in a way that is fiscally efficient and customer-centric. This is a challenge that faces all utilities working to implement smart grid.

NIST Standards

In the United States, the growing national interest in smart grid received a large boost in 2009 with a $4.5 billion investment by the Department of Energy into modernizing the US electric power grid [details at smartgrid.gov]. The subsequent ramp-up in smart grid technology deployment prompted a greater need for standardization.

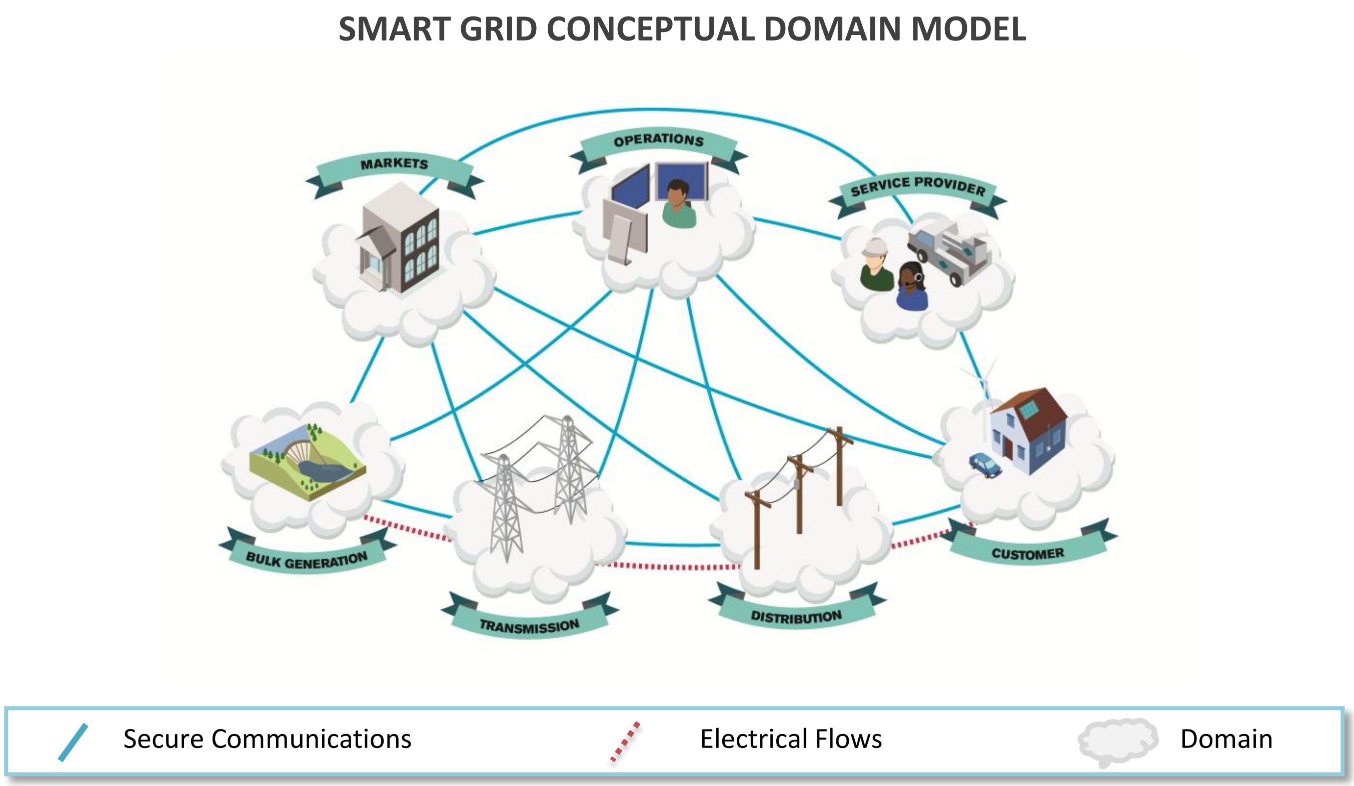
Initiated in 2009 by the National Institute of Standards and Technology (NIST), the Smart Grid Interoperability Panel (SGIP) provides a framework for the standardization discussion by coordinating stakeholder participation and representation that furthers the development and evolution of smart grid interoperability standards. As of 2013, the SGIP operates as a non-profit organization, and its members consist of smart grid stakeholders and organizations spread among 22 categories involved with smart grid integration. The SGIP has three primary functions:

- To oversee activities intended to expedite the development of interoperability and cyber security specifications by standards-setting organizations;
- To provide technical guidance to facilitate the development of standards for a secure, interoperable smart grid; and
- To specify testing and certification requirements necessary to assess the interoperability of smart grid-related equipment.[1]

Recent outputs of the group are descriptive (not prescriptive) smart grid conceptual models intended to aid in analysis, including a domain model and an information network model. They are designed to foster understanding of smart grid operational intricacies, but not prescribe how the smart grid will be implemented.

The Smart Grid Domain Model (Figure 2) and its associated interoperability framework establishes high-level guidelines for identifying actors (or domains) and possible communications paths in the smart grid. It is a useful tool for identifying potential intra- and inter-domain interactions, as well as potential applications and capabilities enabled by these interactions.[2]

Figure 2: Illustration of the Interactivity of the Domains of a Smart Grid

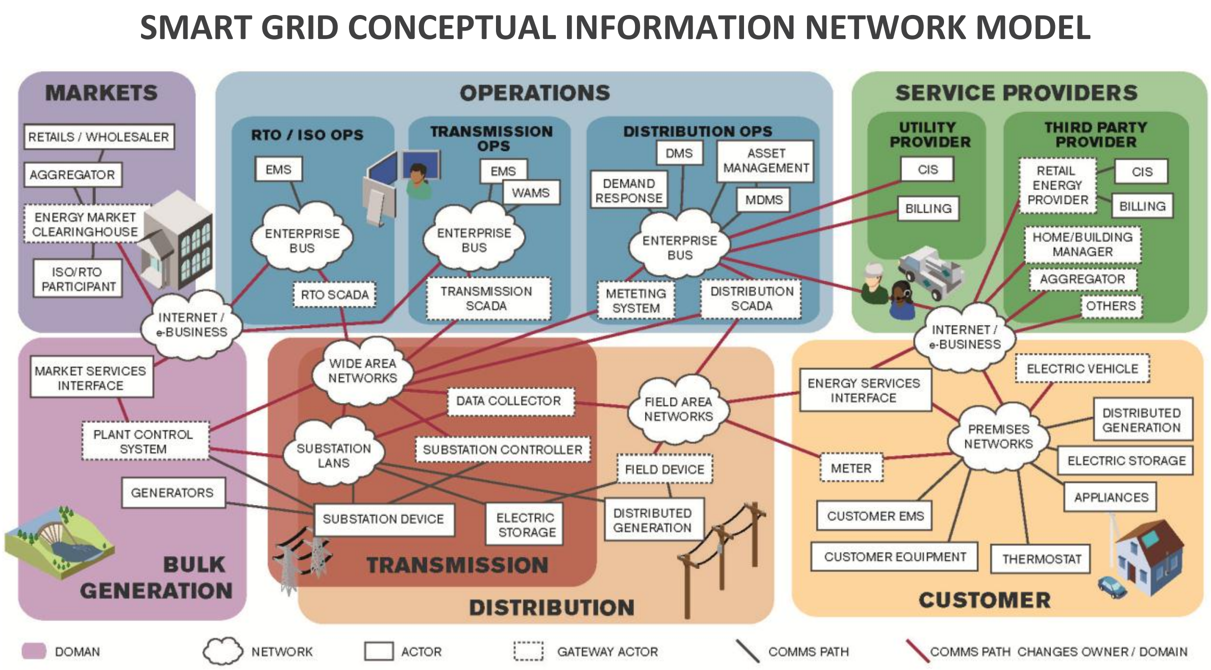


Source: NIST Smart Grid Framework 1.0 January 2012

[1] *NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 2.0*
[2] *NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 2.0*

The Smart Grid Information Network Model (Figure 3) shows many communication paths between and within domains. Various functions are currently supported by independent and often dedicated networks. Examples range from enterprise data and business networks, typically built on the IP family of network protocols, to Supervisory Control and Data Acquisition (SCADA) systems which may utilize specialized protocols. In order to fully realize the smart grid goals of vastly improving the control and management of power generation, distribution, and consumption, the current state of information network interconnectivity must be improved so that information can flow securely between the various actors in the smart grid.[3]

Figure 3: NIST Conceptual Reference Model for Smart Grid Information Networks



Source: NIST Smart Grid Framework

Success Factors

For long-established energy companies like PSE, smart grid implementation requires a thoughtful and strategic approach. New technologies need to be evaluated for their ability to integrate with existing IT networks, back-end applications, and legacy T&D components (some of which are currently working independently from each other). Additionally, careful consideration needs to be given to both the features that create value for customers and as well as the changes likely to affect customers, workforce and utility operations. Determining where value exists for customers, managing this change effectively across the company, and educating customers along the way will be the important success factors.

Smart grid technology advancements and investments will be made at multiple levels of infrastructure. This includes end devices and IT systems that facilitate communications between customers, the utility and the energy grid. It also encompasses the underlying physical infrastructure that operates within substations and extends to the far reaches of the T&D system – all of which must ultimately be integrated with the IT system. This integration will occur through careful planning, consideration of remaining useful asset life and the integration of existing assets, the evaluation of forward compatibility of individual systems as grid assets and the interoperability of associated monitoring, communications and control systems. The resulting costs of these necessary infrastructure and IT investments can be significant, and in some cases may only provide partial benefits until all pieces are integrated.

While the challenges may seem daunting, the benefits are promising.

[3] *NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 2.0*

The work happening at every level provides a rich foundation for learning *(see sidebar)*. How energy companies continue on the path to a smarter energy future will undoubtedly vary. With a significant number of variables, such as regional differences, environment, customer interest, and company size and infrastructure, each company will need to define the path that is most suitable for its set of circumstances.

As smart grid advancements deploy within PSE's service territory, PSE will work to address its own unique operating factors and priorities:

- **Customer = Driver:** PSE will stay in tune with customers who are looking for ways to be more engaged (access to outage information, price, and billing options), as well as those who are already actively engaged in energy matters (participation in energy efficiency programs/pilots and early adopters of electric vehicles and distributed energy generation). Both the energy market and consumers will be an important driver of smart grid advancements for utilities.
- **Reliable service:** Residential and business customers depend on PSE every day for reliable service at a reasonable cost. It naturally follows that the pursuit of smart grid technologies should further enhance this mission.
- **Tempered cost benefits:** Due to the availability of hydropower, the Pacific Northwest has long enjoyed some of the lowest electric power rates in the nation. Relatively lower prices temper some of the immediate cost savings of certain smart grid programs such as time-of-use pricing, but do not change the broader trend toward greater monitoring, communications and control in the energy system. This broader trend, when implemented, leads to additional operations and maintenance savings.
- **Demand-side resource options:** In terms of generated electricity, PSE will need additional resources to meet future capacity needs, largely due to expiring contracts and retiring energy generation assets. PSE's 2013 Integrated Resource Plan (IRP) outlines a need for the utility to add 100 MW of generation capacity and demand-side resources by 2020, and 746 MW by 2025, assuming an additional 1,600 MW of needed capacity is met through short-term purchases. Options to deliver demand-side resources include demand response and dynamic rates. To enable these programs at scale will require substantial investments in smart grid-related communications and back-end information systems to enable two-way communications. These additional infrastructure components must be considered in the context of these trends to ensure the successful timing of their acquisition and deployment to cost-effectively support the expansion of demand-side resources.
- **Demographic shift in utility industry:** Between 2011 and 2020, more than 60 percent of utility industry employees have the potential to retire or leave for unspecified reasons, according to a 2011 Center for Energy Workforce Development report. PSE's workforce is no exception, with 27 percent of employees being eligible to retire in the next five years.
- **Renewable energy integration:** Renewable energy is of significant interest to PSE and our customers. PSE is already producing electricity from the wind and sun, and purchasing electricity generated from landfill and dairy waste products, and we expect these renewable sources to be an increasingly important part of our energy future. Smart grid advancements need to consider the integration of renewable energy, distributed generation, energy storage, thermally activated technologies, and demand response in a way that is aimed toward managing peak loads, enhancing asset use and expanding the energy distribution capabilities of smart grid.

A selection of recent industry findings and lessons learned that are helping to define and lay the groundwork for future smart grid deployment:

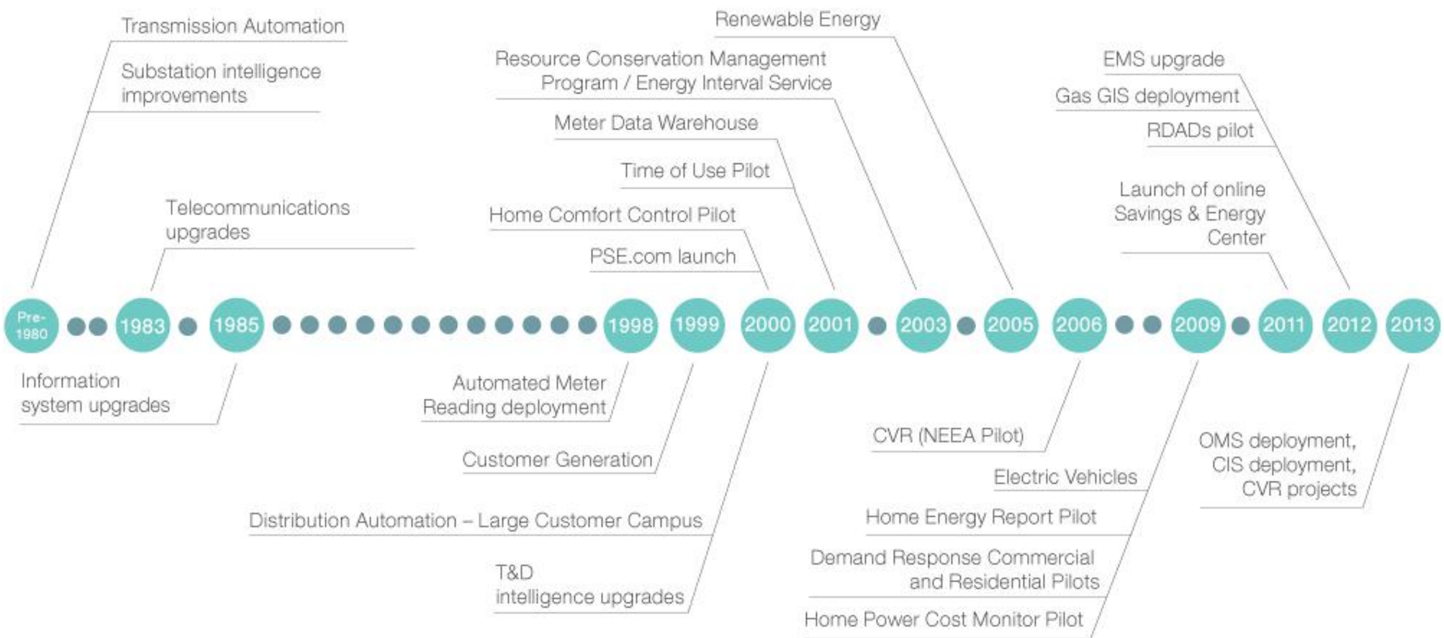
- Delivered customer experience and customer engagement have not kept pace with technology advancements.
- Early and proactive customer engagement is critical to smart grid program success.
- The individuality of electric systems throughout the country requires smart grid implementation in each area to be unique – including the challenge of integrating new technologies on differing legacy systems.
- Project completions are being hindered by discrepancies between projected and actual costs.
- Smart technologies are improving system reliability – utilities are seeing reductions in both frequency and duration of outages.

- **Infrastructure and operational opportunities:** Like many energy companies, PSE is faced with investing in aging infrastructure that will need to be modernized or replaced to ensure reliability for our customers. This presents an opportunity, as updating these systems will allow building for both current and future needs. This upgrade process will also provide PSE with more frequent information (i.e., nearly real-time) at additional points throughout the system, which PSE can use to optimize our current electric infrastructure with timely improvements. Additionally, the new sources of information can allow us to optimize operations in some areas by improving performance or reducing costs.
- **Technology risk awareness:** The technology required to upgrade IT systems and enable further smart grid applications can be at uneven levels of maturity for deployment. While some technologies and applications are proven and at a point where research and development cycles have ended and commercialization has begun, others are in early formation stages and require further development. Furthermore, the technology embedded in many new smart grid applications will continue to evolve at an increasing rate, and may require PSE to replace or upgrade future investments more frequently than in the past.
- **Determine real value:** Even with technologies that continue to make smart grid smarter, PSE is sensitive to all potential impacts to our customers. This means considering the deployment of pilot programs to determine cost-effectiveness and benefits to customers, as well as customer acceptance.

Review of PSE's Smart Grid Initiatives

PSE has been serving our customers with smart grid components for over 35 years – before the term "smart grid" was widely known. Our early experience allowed us to test technologies and learn many lessons about what would later become known as smart grid through a series of projects spanning decades (Figure 4).

Figure 4: PSE's History of Deploying Smart Components



(See Appendix A for more information about PSE's history of deploying smart grid components.)

The last two years have brought about a significant change in the way PSE is able to effectively manage electricity reliability and customer service through the use of more integrated systems. The following chart provides a progress report on the proposed activities, all of which have been completed or are moving forward as anticipated.

At-a-Glance Progress Report of 2013-2014 Proposed Smart Grid Implementation Plan

(As proposed in PSE's plan submitted to the Washington Utilities and Transportation Commission (UTC) dated September 1, 2012.)

✓✓ - Executed on plan	✓ - Pursued plan with some changes	+ - Plan on hold or cancelled for business reasons

Information Technology	Status
Upgrade PSE's Energy Management System (EMS)	✓✓
Upgrade PSE's existing Meter Data Management System (MDMS)	✓✓
Implement PSE's electric Geospatial Information System (GIS) and Outage Management System (OMS)	✓✓
Go live with PSE's Customer Information System (CIS)	✓✓
Continue to develop applications that leverage PSE's natural gas GIS network data	✓✓
Develop an implementation schedule for a Distribution Management System (DMS)	✓
Implement Supervisory Control and Data Acquisition (SCADA) using IP technology on all new substations and major substation rebuilds	✓✓
Complete a technology roadmap for migrating to an Advanced Metering Infrastructure (AMI), including accompanying system requirements and architecture	✓
Initialize PSE's Energy Trading and Risk Management (ETRM) System deployment over 2013-2016	+

Customer Information and Energy Empowerment	Status
Roll out completed redesign of My PSE Account into the existing PSE.com	✓✓
Complete the next phase of enhancements to PSE.com's online tools	✓✓
Continue offering Home Energy Reports to 24,000 customers through 2013	✓✓
Continue to support customer adoption of small renewable generation	✓✓
Continue to analyze Plug-in Electric Vehicle (PEV) trends	✓✓

Transmission and Distribution Infrastructure	Status
Install a transmission line switch and continue to roll out one to two automation schemes per year	✓✓
Continue to work with a large customer to gauge automation improvements that would enhance their electric reliability	✓✓
Continue the recloser installation program expansion on overhead circuits	✓✓
Install Supervisory Control and Data Acquisition (SCADA) switches in PSE's distribution substations, both new and refurbished	✓✓
Expand Remote Data Acquisition Device (RDAD) program in the Bellevue Central Business District (CBD), and determine the technology's next steps	✓✓
Define requirements for, evaluate, and select a distribution automation program.	✓
Implement Conservation Voltage Reduction (CVR) on three to six PSE substations before energy is sent to customers, thereby reducing customers' electric power consumption at the point of consumption on the customers' side of the meter	✓✓

(See Appendix B for more information about progress report details.)

With our experience (e.g., an early commitment to automated meter reading, self-healing transmission lines, and utility-scale wind generation), PSE has been able to progress at a measured pace, moving toward developing the operations network, implementing prudent projects, and improving our operations, service, security, and customer relationships.

PSE’s Current Approach

PSE has been and will continue closely monitoring NIST security and interoperability standards development and adopting the results. A key principle of these emerging standards is to ensure that secure communications occur between smart grid “domain actors” (refer back to Figure 2). PSE has incorporated this essential tenet as part of the fundamental design framework in our operations network architecture. As new standards are adopted, we will work to align our business accordingly.

PSE will continue to learn about new technology innovations through industry research and our own pilot programs. We will remain flexible, agile, and open to change. Once a new technology is proven to help provide reliable, safe, and secure energy services at a reasonable cost, we will consider its widespread implementation.

PSE’s smart grid initiatives continue to fall into three broad categories: 1) information technology (IT), 2) customer information and energy empowerment, and 3) transmission and distribution (T&D) infrastructure. In these areas we find that our employees and customers can work together through the smart grid to achieve the highest levels of safe, dependable, efficient and secure service.

In IT, PSE will continue building out and strengthening our core enabling capabilities – the foundation of smart grid. This includes continued enhancements to our CIS, GIS and OMS systems and upgrades to our EMS and MDMS systems.

As requirements evolve, PSE will continue to develop its systems architecture to ensure PSE’s security, compliance and business requirements are met, and align with NIST architecture standards. With several core capability projects already implemented, including a number of upgrades to our back-end information systems, we expect our smart grid maturity level to significantly increase over the next 10 years.

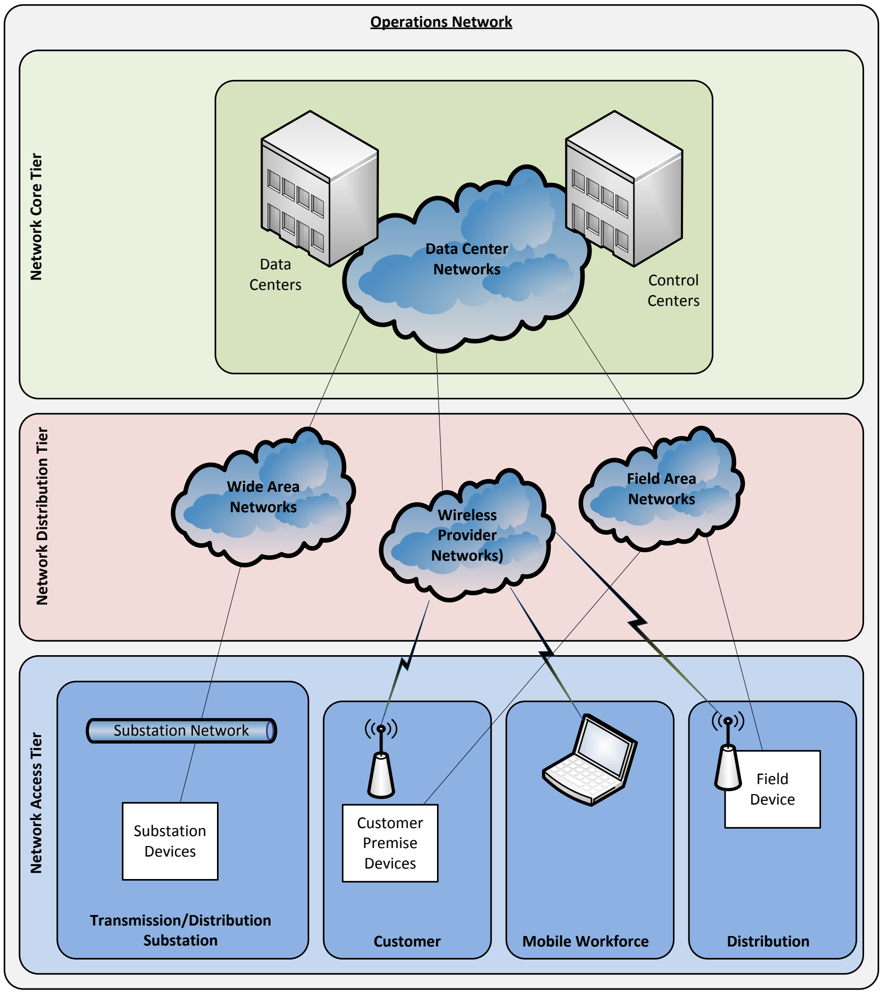
In the area of customer information and energy empowerment, PSE will continue working over the next several years to initiate or continue pilots and programs that will allow us to effectively test the capabilities of new technologies and anticipate customer needs. Additionally, PSE’s core values around customer service will likely drive initiatives to gather customer feedback and allow us to better tailor our offerings.

In transmission and distribution infrastructure, PSE’s most fundamental smart grid initiative will be the continuation of improvements to aging infrastructure, the completion of planned initiatives targeted to increase reliability for customers and reduce outage duration, and learning from pilots and others.

PSE's Operations Network Model

The Operations Network at PSE is a "network of networks" being constructed with the NIST reference Architecture as a guide. This network includes the elements of a core network, a wide area network, field area networks, and others, as the network grows:

Figure 5: PSE Operations Network



These networks together provide highly reliable and secure transport of data signals related to the operation, management, control, and monitoring of energy. That is; it provides the foundational enabling data signal transport for Smart Grid capabilities. This includes but is not limited to data signals related to:

- Energy Control Systems; including SCADA
- Time-series data historians (PI, a data storage and analysis software application)
- Metering; One-way (AMR) and Two-way (AMI)
- Distribution Automation (DA), Demand Response (DR)

PSE is embarking on a number of projects discussed in this report, which are being leveraged to build elements of the Operations Network, strengthen and improve existing elements, and/or increasing security and reliability of Operations data transport. As requirements evolve, PSE will continue to plan and update the Operations Network Architecture to ensure that the Operations Network will meet PSE's security, compliance, and business requirements, and will align with the National Institute of Standards and Technology's Smart Grid Reference Architecture.

Automation and PSE’s Road Map

Through feedback gathered in surveys and customer calls, PSE’s customers have indicated that they value reliability as a top priority. Reliable power has always been at the core of PSE’s business. Traditional approaches to outage reduction such as undergrounding distribution power lines, using plastic-coated conductors (tree wire) on overhead power lines where tree limbs are near or touching power lines, and conducting regular patrols of circuits to proactively identify aging or damaged equipment have benefited our customers. Such measures are, however, expensive to implement in all locations where they would be beneficial. PSE has determined that a complementary approach is needed that incorporates automation technology to deliver the high reliability that our customers expect, and this approach is reflected in many of the aspects outlined in the 10-year road map above.

For several years, PSE has operated an automation scheme on the circuits that feed the campus of a large commercial customer. Today, if an outage occurs in this area, automated circuit reconfigurations can restore power within minutes instead of the hours a manual restoration effort could take. Since this automation scheme was initially introduced, the technology available has evolved to an effective and ubiquitous reliability solution for utilities. PSE continues to build expertise within automation, and ultimately aims to bring this capability to more areas of our service territory to benefit many more of our customers.

Recognizing the potential of this technology, PSE has developed requirements for automated Fault Location, Isolation, Sectionalization and Restoration (FLISR) solutions. Our approach is to standardize our processes and technology on solutions that can be used throughout our service area: with both underground and overhead circuits, and in rural, suburban and urban settings. PSE will then use these standards to evaluate competing solutions through our bidding and procurement processes. While automation technology may not prevent an outage altogether, it is able to reduce the duration of outages and reduce the number of customers impacted by the outage.

Furthermore, PSE continues to communicate and cooperate with peer utilities across the US and Canada to incorporate lessons other utilities learn through pilot programs and initial rollouts into its own strategy development. Through such communication, PSE is able to ascertain the value of automation technologies as they would apply to its own specific customer base, service area, and generation profile, and tailor its own implementation plan and 10-year road map.

PSE's Implementation Plan (2015-2016) and 10-year Roadmap (2015-2025)

As with its previous roadmaps, PSE's smart grid technology implementation plan continues to take into account the regional landscape and our integration approach. Each project in Appendix B fits into our overall map of where we see ourselves and our customers heading over the next 10 years. Our plan focuses on the business needs that will drive the implementation of smart grid technologies, and it also describes how we will support our customers as they plot their own paths into the world of smart grid. **These plans may be adjusted as we learn from our current activities and pilots and the industry at large, and as our customers learn more about their needs/desires. Our plans are also subject to resource and budget considerations, as well as technological changes and capabilities.**

Over the next 10 years, PSE will continue to:

- Upgrade and replace aging infrastructure as needed – on IT networks, back-end information systems, and T&D systems – with consideration given to implementing a smarter grid;
- Build out the Operations Network and increase the security and reliability of operations data transport;
- Work with customers on the development of easy-to-use energy management capabilities, reporting tools/information, and general applications of technologies;
- Support customer energy needs/desires (e.g., electric vehicles, customer energy generation);
- Evaluate and strategically deploy two-way automated metering technology, expand the operations network into our distribution system over a new AMI network;
- Evaluate and strategically deploy self-healing and automated rerouting of power through automation to improve electric system reliability; and
- Evaluate and strategically deploy other customer energy management capabilities.

As technologies continue to evolve and our customers and the market present us with new smart grid opportunities, we will review, evaluate and potentially pilot projects or implement activities in the following areas:

- Electric vehicles;
- Automation, self-healing, enhanced demand response and the ability to integrate traditional and nontraditional energy sources (e.g., wind, solar) in the grid;
- Home intelligence/automation;
- Energy storage technology;
- Using storage and/or distributed generation to supplement peak power needs on the grid.

The following tables give an overview of PSE's plans in the areas of information technology, customer information and energy empowerment, and transmission and distribution infrastructure. Note that each project/area has been identified with the benefitting NIST smart grid domain (Figure 6). This mapping was developed with an eye toward the future, so that PSE may more readily compare our efforts with those of other utilities as the NIST model is adopted across the country. In addition, we have mapped each project's relationship to relevant smart grid functions as Defined by WAC 480-100-505 (Figure 7).

Figure 6: PSE's Proposed Smart Grid Activities. Align with Relevant NIST Standard Domains.

NIST Smart Grid Domains		PSE Smart Grid Areas		
		Information Technology	**Customer Empowerment**	**Transmission and Distribution**
	Operations	EMS		
		DMS		
		OMS		
		Substation IP Enablement		
	Service Provider	CIS	CIS	
		Automated Metering	Automated Metering	
	Customer	MDMS	PSE.com	
		Automated Metering	Home Energy Report	
			Customer Energy Generation	
			Electric Vehicles	
	Distribution	GIS		Distribution Automation
		Substation IP Enablement		CVR Grid-Scale Battery Project
	Transmission	GIS		Transmission Automation
		Substation IP Enablement		
	Markets	Energy Trading and Risk Management		

Figure 7: PSE's Proposed Smart Grid Activities Align with Relevant WAC 480-100-505 Smart Grid Domains

		PSE Proposed Smart Grid Activities																
		EMS	MDMS	CIS	GIS	DMS	OMS	Substation IP Enablement	Automated Metering	ETRM	PSE.com	Home Energy Report	Customer Energy Generation	Electric Vehicle	Distribution Automation	Transmission Automation	CVR	Grid Scale Battery Storage
Smart Grid Function as Defined by WAC 480-100-505	The ability to develop, store, send and receive digital information concerning electricity use, costs, prices, time of use, nature of use, storage, or other information relevant to management of the electricity grid, utility operations, or customer energy use.	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓	✓	✓	
	The ability to sense local disruptions or changes in power flows on the electricity grid and to communicate such information instantaneously and automatically for purposes of enabling automatic protective responses or to inform the utility to make manual changes to sustain reliability and security or improve efficiency of grid operations.	✓		✓		✓	✓						✓		✓	✓		✓
	The ability of the utility to deliver signals, measurements or communications to allow an end-use load device to respond automatically or in a manner programmed by its owner or operator without human action.		✓	✓		✓	✓		✓	✓			✓	✓				
	The ability to use digital information to operate functions on the electricity grid that were previously electromechanical or manual.	✓		✓		✓	✓	✓	✓	✓			✓		✓		✓	
	The ability to use digital controls to manage and modify electricity demand, enable congestion management, assist in voltage control, provide operating reserves, or provide frequency regulation.	✓	✓	✓		✓	✓	✓	✓	✓			✓	✓		✓	✓	✓
	The ability to use two-way communication to enable different customer contracts or programs, such as real time prices or demand response programs.		✓	✓					✓	✓	✓		✓	✓				
	The ability to manage new end-use services to reduce operating or power costs, improve reliability, or improve energy efficiency, such as charging electric vehicles.		✓	✓					✓	✓	✓		✓	✓				
	The ability to use real time measurement of power generated from customer-owned power facilities to reduce operating or power cost, improve energy efficiency, or improve reliability.		✓	✓			✓		✓	✓			✓	✓				
	The ability to use digital information to improve the reliability or efficiency of generating equipment in an integrated manner to improve flexibility, functionality, interoperability, cyber-security, situational awareness, and operational efficiency of the transmission and distribution system.	✓	✓			✓	✓	✓		✓			✓					✓

The following sections outline PSE's two-year implementation plan and 10-year roadmap, with projects categorized into one of three major fields. Additional information on specific individual smart grid components or projects is provided in Appendix C.

Information Technology

PSE is embarking on a number of projects (outlined below) which will be leveraged to build, strengthen, and improve PSE's core information systems while increasing security and reliability of data transport related to the operation, management, control and monitoring of energy. The benefits of this major undertaking include improved outage detection and restoration, enhanced customer service/communication, and improved billing and payment options. Essentially, PSE is creating the foundation to enable all smart grid capabilities.

With several core capability projects already underway, including building and strengthening PSE's core operations network, and the upgrade or deployment of CIS, OMS and GIS, PSE is better positioned to meet utility and customer demands, and to enable the future of smart grid.

Smart Grid Enablers

2015-2016 Plan

- Meter Data Management System (MDMS)
  - Complete the MDMS upgrade.
  - Consider integrating near real-time Web interface.
  - Implement CIM standard interface for information.
  - Implement a disaster recovery capability to further enhance the MDMS' reliability.
- Customer Information System (CIS)
  - Continue with system stabilization and process integration.
- Gas Geospatial Information System (GIS)
  - Consider additional applications to leverage GIS.
- Distribution Management System (DMS)
  - Continue with evaluation of available DMS solutions in the market.
- IP SCADA Enablement
  - Continue implementation of SCADA using IP technology at substation and generation facilities.

10-year Roadmap

- Complete OMS-DMS-EMS-CIS-MDMS integration.
- Implement and add elements (e.g. generation) to an enterprise-wide GIS.
- Complete integration of MDMS to outage and engineering applications.
- Migrate substations that requiring back-up control-center communications to IP.
- Continue extension of fiber optics cabling throughout T&D network.

Automated Metering

2015-2016 Plan

- Explore additional technology and process improvements within current AMR architecture. Continue to evaluate AMI technology and business value, consider targeted deployments, and refine roadmap for AMI implementation.

10-year Roadmap

- Continue AMR-AMI conversion, as appropriate.

Energy Trading and Risk Management

2015-2016 Plan

- Implement project to replace a gas management system and a gas for power system.

10-year Roadmap

- Complete implementation of integrated ETRM solution, including a power management system and integrated resource management analytics.

Customer Information and Energy Empowerment

Customer adoption continues to be a key driver in PSE's deployment of customer facing smart grid technologies. For example, electric vehicles and charging stations, customer energy generation, demand response and home automation can all affect the grid at its most local level. As new customer installations change and begin to increase peak load on our T&D system, PSE will need to consider several smart grid capabilities to help manage and optimize the system – from improved access to immediate data from the grid to customer programs such as demand response and load control.

Growing customer interest in energy management may drive the need for more easy-to-use energy management and reporting tools, better information through two-way automated metering technology, and other customer energy capabilities such as household energy usage or appliance monitoring and adjustment. Anticipating customer needs/desires will also drive our need to find new solutions for security and customer privacy. All of these facets will help smart grid technology balance energy delivery and load utilization.

Energy Use Information and Feedback

2015-2016 Plan

- My PSE Account – Continue work to improve overall usability of the site through back-end improvements and redesigns as needed.
- PSE.com/Online Tools – Implement new, more personalized online energy management tools for customers to take better control of their energy use.
- Home Energy Report – Continue to support the 2014 wide-scale rollout of the Home Energy Report to 100,000 customers.

10-year Roadmap

- Continue to review and evaluate proposals for additional Web components and applications; consider the deployment of pilots and/or programs to learn the potential savings and value proposition to customers.

Customer Energy Generation

2015-2016 Plan

- Anticipate and support continued rapid program growth (4,500 net-metered customers are projected by the end of 2017).
- Evaluate opportunity for pilots and/or projects involving smart meters and direct-to-customer-computer/smart phone messaging.

10-year Roadmap

- Continue to monitor consumer/market changes and technology advances for program enhancements and/or changes.

Plug-in Electric Vehicles (PEV)

2015-2016 Plan

- Implement an electric vehicle charger program to gather updated information on vehicle charging locations and load curves specific to PSE's customers. Compare these results with earlier analysis, PSE's normal system load shape, and renewable resources.
    - Compare methods to monitor PEV energy usage, including monitoring through "smart chargers", using PSE's existing meter systems, and vehicle data, if available.

- Assess “smart chargers” capability.

10-year Roadmap

- Develop energy and demand forecasts based on already experienced adoption rates and needs.
- Incorporate PEV loading and forecasts into distribution and transmission planning, and design standards where appropriate.
- Scale a program in step with IT communications, meter rollouts and customer demand where the business case demonstrates overall benefit to customers and PSE.

Transmission and Distribution Infrastructure

Driven by our objective to provide safe and reliable service, PSE will continue to explore, evaluate and selectively deploy smart grid T&D strategies. For each smart grid solution we consider, we will take into account the diversity of our service area (i.e., downtown core, suburban, rural) as well as the reliability challenges brought on by high trees and vegetation density in the service territory.

By coordinating efforts between T&D and IT, PSE will work to maintain appropriate cost/benefit ratios at each stage as operations network and end-use application upgrades and consolidation are planned.

Transmission Automation and Reliability

2015-2016 Plan

- Continue program to upgrade existing transmission automatic switch schemes as needed. These upgrades will be based on specific benefit, cost and available funding.

10-year Roadmap

- Depending on project specific benefits and cost, as well as available budget funding, continue toward the goal of having supervisory control of all automatically controlled switches.
- Continue to upgrade aging/older SCADA systems in transmission substations.
- Based on benefit/cost analysis, selectively replace aging components with modernized equipment that will facilitate smart grid adaptability.

Distribution Automation Projects

2015-2016 Plan

- Large Customer Campus
    - Continue to work with a large customer on its SCADA and automation needs.
- Distribution Recloser Program
    - Continue expansion of the recloser installation program on overhead circuits, and evaluate the benefits of their communication and monitoring capability.
- Distribution Supervisory Control and Data Acquisition (SCADA) Program
    - Continue to upgrade the distribution SCADA on existing substations; select projects based on specific benefit, cost and available funding.
    - Install supervisory control on feeder breakers and ampere readings on all three phases of breakers at new and other selected distribution substations.
- Remote Data Acquisition Devices (RDADs) Pilot
    - Monitor RDADs currently installed, and evaluate different communication protocols to determine the most suitable solution for a large-scale technology deployment.
- Distribution Automation - Bellevue Central Business District (CBD)
    - Prioritize and then retrofit switches in the Bellevue CBD area to facilitate remote switching.
    - Evaluate an overall distribution automation program that can be implemented on a wide scale.

- Conservation Voltage Reduction (CVR)
  - Implement CVR on three to six substations annually to improve efficiency of selected distribution circuits by reducing line voltage at a distribution substation from the typical 120 volts down to 117 volts (typical for residences) before energy is sent to customers, thereby reducing customers' electric power consumption at the point of consumption on the customers' side of the meter.

10-year Roadmap

- Expand distribution automation in areas with high critical load and/or reliability concerns.
- Continue expansion of recloser installation program and expand communications and monitoring capabilities depending on benefit/cost.
- Continue expansion of SCADA functionality at all distribution substations with the goal of providing three-phase ampere readings of each breaker and supervisory control of the feeder breakers.
- Depending on pilot results, deploy RDADs into the limited access parts of PSE's service area.
- Expand CVR program to appropriate locations where cost-effective implementation yields further energy savings by reducing customers' electric power consumption at the point of consumption on the customers' side of the meter.

For full details of PSE's two-year smart grid implementation plan and 10-year roadmap, as well as descriptions of smart grid technologies PSE has considered or is considering for integration into our system, please refer to Appendix C.

Conclusion

Smart grid technologies have the potential to provide significant improvements in grid operations, reliability, energy production, and customer service, benefiting utility operations and customers alike. These capabilities will also strengthen the nation's energy infrastructure, but will also require utilities to focus their efforts on several aspects of the system deployments to ensure their successful transitions to more functional systems.

One key to successful smart grid deployment will be the prudent and systematic introduction of smart grid technology at each level of infrastructure: from T&D and IT systems, to customer premises applications and information systems. Not only will this approach help to avoid system-wide interoperability issues, it will also aide PSE in understanding which technologies are most useful to and desired by PSE customers.

A second focal area for smart grid technology investment will be the maturity of the technology itself. Because smart grid technology is continually evolving, a prudent approach will include the comprehensive evaluation of smart grid technologies. These evaluations will ensure that technologies deliver anticipated benefits and results; that they are interoperable and compliant with industry standards; that vendors will continue to support and develop/improve the technologies over time; and that the technologies are cost-effective.

A third critical focal area will be the financial provisioning for smart grid technology investments. These investments must be balanced with the realities of rate schedules, cost recovery and the acceptance levels of customers before they are systemically deployed.

Finally, the role of the customer as ultimate beneficiary of smart grid products and services should not be understated or underestimated. PSE is in a service business, and the reliability and cost-effectiveness of the energy we provide to our customers enables them to operate their homes and businesses. Active collaboration and open communication channels to customers are important values within PSE, and are mission-critical components of every project (smart grid or other) that PSE undertakes. By giving thought to each of these aspects, PSE aims to continue its own system improvements that lie within the domain of smart grid.

Glossary

Definition of Acronyms and Terms

AMI – Advanced Metering Infrastructure.

Ampere – Unit of electric current or a measure of the amount of electric charge passing a point per unit time.

AMR – Automated Meter Reading.

Applications – Hardware or software functions designed to perform single or multiple related and specific tasks.

Back-end Information Systems – Information systems that are invisible to the end user, but that handle a majority of the processing behind the transactions that the end user executes.

BPA – Bonneville Power Administration.

Capacitor – A device for accumulating and holding a charge of electricity, consisting of two equally charged conducting surfaces having opposite signs and separated by a dielectric.

CIP – Critical Infrastructure Protection.

CIS – Customer Information System.

Charging Station – A conveniently situated physical location where electric vehicles can be charged/recharged with electricity.

Conservation – Any reduction in electric power consumption resulting from increases in the efficiency of energy use, production, or distribution.

Conservation Voltage Reduction (CVR) – Reducing line voltage at a distribution substation from the typical 120 volts down to 117 volts (typical for residences) before energy is sent to customers, thereby reducing customers' electric power consumption at the point of consumption on the customers' side of the meter.

Control House – Is usually located at the substation and contains switchboard panels, batteries, battery chargers, supervisory control, power-line carrier, meters, and relays. The control house provides all weather protection and security for the control equipment.

Customer Energy Generation – Energy produced by a utility's customers (e.g. solar panels, wind turbines).

Demand Response (DR) – Managing customer consumption of electricity in response to supply conditions in an electricity grid.

Demand-side Resource – Energy efficiency measures, demand-response, and other techniques that reduce the amount of power customers need (or "demand") in order to operate their homes and businesses. These resources generally originate on the customer side of the meter, whereas supply-side resources are generated and then transmitted (or "supplied") to customers.

Distribution Automation (DA) – The extension of intelligent control over electrical power grid functions in the electric distribution network to minimize outage time to customers. With distribution automation, the energy distribution network will automatically restore service to some customers when a fault occurs on the system. This greatly reduces the outage time experienced by some customers.

Distributed Generation – Electric generation that is located close to the particular load that it is intended to serve. General, but non-exclusive, characteristics of these generators include: an operating strategy that supports the served load; and interconnection to a distribution or sub-transmission system (138 kV or less).

DMS – Distribution Management System.

DNP – Distributed Network Protocol.

DOE – Department of Energy.

Domain – A specific area of functionality. There are seven domains related to smart grid, as outlined by NIST – Operations, Service Provider, Customer, Transmission, Distribution, Markets and Bulk Generation.

DR – Demand Response.

EIS – Energy Interval Service.

EMS – Energy Management System.

Energy Interval Service (EIS) – An online energy management tool displaying 15-minute, hourly and daily energy that PSE provides to business customers participating in PSE's energy efficiency grant and rebate programs.

Feeder or Feeder Circuit – An overhead or underground line or circuit that transports electricity from a distribution substation to homes and businesses (also known as a distribution line).

FERC – Federal Energy Regulatory Commission.

Fiber Optic – Technology used in fiber optic cables that features the transmission of light signals via glass fibers for superior data transport.

Geospatial Information System (GIS) – A computer system for capturing, storing, checking, integrating, manipulating, analyzing and displaying data related to positions on the Earth's surface. Typically, a GIS is used for handling maps of one kind or another.

GIS – Geospatial Information System.

HMI – Human Machine Interface.

Home Automation – The control of domestic appliances by electronically controlled systems.

Human Machine Interface (HMI) – A PC-based system that allows a human being to interact with computing and other mechanical equipment in a transmission/distribution substation.

IEEE – Institute of Electrical and Electronics Engineers.

Intelligent Electronic Device (IED) – A single device that can function as a programmable logic controller, a substation LAN node, an IED gateway, a bay level controller, a revenue class meter (non-certified), a power quality monitor, or a fault/event (waveform) recorder.

IRP – Integrated Resource Plan.

IT – Information Technology.

kV – Kilovolt.

Legacy System – A computer system that continues to be used either because the cost of replacing or redesigning it is expensive, or because there is no modern replacement system capable of performing the functions of the legacy system.

Load Balancing – The use of various techniques by electrical operations organizations to improve system performance and ensure current flow is the same on each of the three phases of a polyphase distribution system.

MDMS – Meter Data Management System.

MDW – Meter Data Warehouse.

NERC – North American Electric Reliability Corporation.

Net Metering – Technique where energy usage for a given residence or business is determined by netting the energy generated by the home/business for the grid against the energy from the grid that the home/business uses.

NIST – National Institute of Standards and Technology.

OMS – Outage Management System.

PEV – Plug-in Electric Vehicle.

Plug-in Electric Vehicle (PEV) – A vehicle that is powered entirely or partially by electricity with the ability to plug in to the electric grid.

Prepay Billing System – A meter- or billing-based solution in which customers pay for electricity before it is consumed. Customers purchase a certain amount of "credit" in advance and must purchase additional credit before they have consumed the amount of electricity necessary to deplete the fund in the account.

Proprietary Technology – Technology licensed under the exclusive legal right of its owner, and often able to be run only on that owner's equipment.

PV – Photovoltaic.

RCM – Resource Conservation Management.

RDADs – Remote Data Acquisition Devices.

Recloser – An electrical circuit device that recloses an interrupted high voltage electric circuit system to restore power.

Remote Data Acquisition Devices (RDADs) – Devices installed on conductors that measure and report daily using cell phone technology an hourly snapshot of the amount of current present. It can also determine if a fault condition occurs and will immediately send a message to PSE's System Operations.

Remote Terminal Unit (RTU) – A device installed at a remote location that collects data, codes the data into a format that is transmittable, and transmits the data back to a central station.

Renewable Energy – Energy that is capable of being replenished (e.g., solar, wind) after it has been consumed.

Renewable Resource – (a) Water; (b) wind; (c) solar energy; (d) geothermal energy; (e) landfill gas; (f) wave, ocean, or tidal power; (g) gas from sewage treatment facilities; (h) biodiesel fuel as defined in RCW 82.29A.135 that is not derived from crops raised on land cleared from old growth or first-growth forests where the clearing occurred after December 7, 2006; and (i) biomass energy based on animal waste or solid organic fuels from wood, forest, or field residues, or dedicated energy crops that do not include (i) wood pieces that have been treated with chemical preservatives such as creosote, pentachlorophenol, or copper-chrome-arsenic; (ii) black liquor by-product from paper production; (iii) wood from old growth forests; or (iv) municipal solid waste.

RTU – Remote Terminal Unit.
System Average Interruption Duration Index (SAIDI) – a widely accepted measurement of a utility's reliability. SAIDI measures the minutes of sustained outages per customer per year. This metric does not include planned outages or outages lasting fewer than five minutes.

SCADA – Supervisory Control and Data Acquisition.

Self-Healing – Technology capable of automatically repairing itself.

SGIP – Smart Grid Interoperability Panel.
Smart Charger – A charger that monitors a battery's resistance and voltage, and that adjusts charge delivery to maximize its efficiency and longevity.

Smart Grid – A term used to describe the integration of intelligent devices and new technologies into the electrical grid to optimize the system to a degree not possible with existing infrastructure.

Smart Grid Interoperability Panel (SGIP) – A panel of stakeholders from the entire smart grid community in a participatory public process to identify applicable standards, gaps in currently available standards, and priorities for new standardization activities for the evolving smart grid. The SGIP supports NIST in fulfilling its responsibilities under the 2007 Energy Independence and Security Act.

Standards – Technical specifications that various industry vendors, companies and consortiums define and then agree to in order to guarantee equipment and software interoperability.

Substation – An energy generation, transmission or distribution facility where voltage is transformed from high to low or the reverse by using transformers.

Supervisory Control and Data Acquisition (SCADA) – A computer system for gathering and analyzing real-time data that is used to monitor and control substation equipment.

Switchgear – A combination of electrical disconnects, fuses and/or circuit breakers used to isolate electrical equipment.

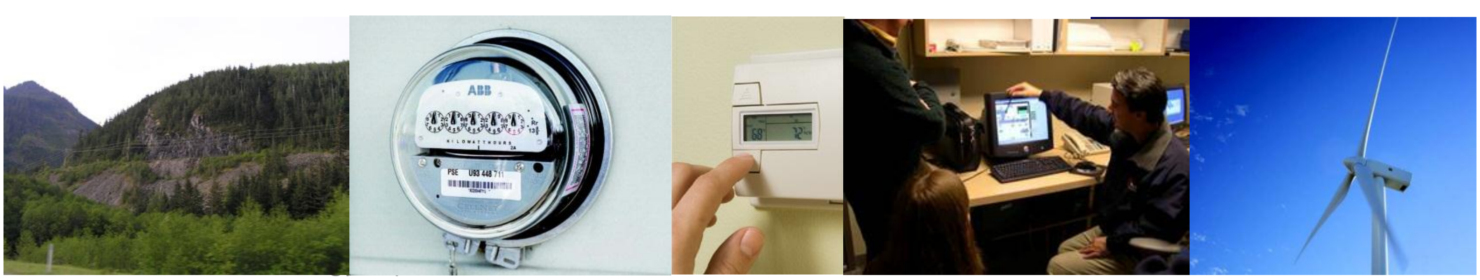
T&D – Transmission and Distribution.

TA – Transmission Automation.

Transmission Automation (TA) – Intelligent technology that enables the transmission system to run itself without human intervention.

V/kV – Volt/kilovolt.

Voltage Ampere Reactive (VAR) – A unit used to measure reactive power in an alternating current (AC) electric power system. Reactive power is the loss of power in an AC power system, which is due to the production of electric and magnetic fields. Reactive loads dissipate no power, but they drop voltage and draw current, creating the impression that they actually do. As a result, reactive power is sometimes referred to as "imaginary power" or "phantom power." Reactive power must be provided and maintained to ensure continuous voltage, so it is produced not for end-use consumption, but for system maintenance.



Appendix A

PSE's History of Deploying Smart Grid Components

PSE's history of deploying smart grid components dates back to before 1980. Following is a description of each of the components identified on the historical timeline featured on page seven of this report.

Pre-1980 to Present

Transmission Automation

Automation technology was first applied to PSE's transmission system in the 1970s, starting with transmission line switching that opens and closes automatically (without operator action) to isolate faulted sections of the high voltage line. The purpose was to improve reliability by quickly sectionalizing and isolating the faulted or failed sections of the transmission line; and then restoring service to the rest of the line. In addition, some switches were enhanced with SCADA and "supervisory control," which enabled remote operation by the system operator.

Over time, "schemes" were designed that combined several automated switches with increasing logic and control, and the number of different switch operations and levels of sophistication steadily increased.

Today, PSE's 55-230 kV transmission systems include more than 90 automatic switch schemes, and many of the older schemes have been improved. All lines have remote monitoring and control, and nearly all are designed to self-heal.

Substation Intelligence Improvements

Substation SCADA: Prior to 1970, PSE substations had very few SCADA capabilities. A substation equipped with SCADA allows the system operator to view and control the status of its equipment. Limited information from the T&D substations was gathered over telephone lines, with larger substations having manned control centers onsite.

Substation circuit breakers were automated to trip and reclose in the case of a power failure, but the status was not known remotely. In the early 1980s, remote terminal units (RTUs) were added that allowed for the remote status and control of transmission system breakers and switches. During this time, SCADA could only allow slow speed communications to a central "host" computer, but there was no way to integrate the signals received from the field with the RTUs. By the mid-1980s, integration with RTUs began to occur with the systematic replacement of electro-mechanical relays and meters with intelligent electronic devices (IEDs). In 2009, PSE initiated a new phase of SCADA evolution by beginning the conversion of its SCADA analog system to digital format. Digital format facilitates communications between T&D network components for interoperability.

Substation Digital Relay Upgrades: From 1950-1985, PSE installed and used electro-mechanical relays in our T&D infrastructure. Some of these relays are still in service, but a majority of them have been upgraded to digital relays in a replacement effort that began in 1985 and still continues. Advantages of digital relays include multiple inputs, multiple setting groups, greater flexibility in setting selection and protection schemes, faster response times, time synchronization, fault distance logic/calculation, and remote status reporting, interrogation and programming.

Substation Capacitor Automatic Switching: In 2005, PSE began installation of automatic control to distribution substation capacitor units to respond to system needs and provide status information remotely to system operators. This provides more accurate and timely reliability support while increases the system efficiency.

Transmission Line Fault Locating: Prior to 1985, locating a fault on a several-miles-long transmission line consisted of a manual line patrol. This typically took several hours, and was often exacerbated by line access difficulties. Since then, we began installing digital relays that enable fault distance calculations in several locations on some of our transmission lines. The relays help calculate the location of the fault, speeding up assessment and restoration. As we convert older electromechanical transmission relays to digital ones, this feature is a standard addition.

Substation Human Machine Interface: Because early substations had little automation and no remote status reporting or control, operators visiting the substations had to rely on panels that used incandescent light-bulb labels for system information. In 2000, a new Human- Machine Interface (HMI) was introduced as part of the newer substation control houses. HMI PCs and software collect status/loading information in a real-time mode with historical data available. The display allows a user to visually inspect the condition of the substation, and to perform local control as needed. The HMI allows for faster assessment of the substation by local personnel, and enables information verification between field and central operations in a real-time mode.

1983

Telecommunications Upgrades

In 1983, PSE began upgrading and integrating a telecommunications infrastructure that now provides connectivity to roughly 800 locations, including service centers, generating plants, electric substations, gas gate stations, and any other locations requiring communication. This infrastructure transports a wide variety of information, including voice, data, SCADA, alarm, security, protection, and radio. It consists of leased telephone services, including hundreds of circuits from over a dozen providers, and PSE's private network equipment, including approximately 600 miles of owned fiber optics lines and 46 microwave paths.

Key telecommunications upgrade milestones include:

- First Digital Microwave – Installed in 1983 between Mt. Blyn and Mt. Erie to increase capacity and reliability of communications to the Kitsap Peninsula
- First Fiber Optic Cable – Installed in 1984 between the Eastside Operations Center and Sammamish substation to facilitate substation control
- First TDM (time-division multiplex) Network Management System – Installed in 1997 to provide automatic diverse routing of communications circuits between approximately 10 sites
- First VoIP Phone System – Installed in 2003 in association with the new corporate office
- First Diverse IP Core Network – Installed in 2009 between the Corporate Office (Bellevue campus), 24x7 Operations Facility (Eastside) and Customer Access Center in Bothell

Today, PSE's communications are managed primarily through two types of systems, one IP and the other TDM. There are two IP systems, one for corporate data and one for energy control. The TDM system carries all non-IP communication, both analog and digital.

1985

Information System Upgrades

Between 1985 and 2000, PSE acquired or developed most of the back-end legacy information systems (e.g., CIS, EMS, components of an OMS and DMS) that supported PSE's business. From 2000-2009, PSE developed seven discrete, secure networks to serve as the communications backbone for PSE's gas, electric and information assets, and continued to enhance its back-end information systems to reflect PSE's evolving business needs. Recognizing that many of its information systems would not continue to be sustainable with new and emerging business needs, PSE initiated RFI/RFP processes as well as overall system and network architectural studies in 2008-2009. These studies helped determine PSE's future direction and system replacement/upgrade strategies, as well as its path for consolidating communications into one or two company networks under a virtual private network (VPN) structure. In 2009, PSE also began participation in the NIST Smart Grid Interoperability Panel (SGIP) and NERC-defined Critical Infrastructure Protection (CIP); and completed and installed the data warehouse and reporting system that monitors customer energy usage.

1998

Automated Meter Reading Deployment

PSE began discussions of moving to an Automated Meter Reading system in 1995, and conducted three pilot programs with the technology over a three year period. The AMR system uses a one-way radio frequency transmission from the meter to report consumption data. After selecting a product, deployment ran from 1998 – 2002, at which time all but 70,000 meters were changed. The final phase to install AMR on those remaining 70,000 meters was completed during the summer months of 2006. Total automation today includes just over 1.9 million natural gas and electric meters.

1999

Customer Generation

PSE's support of customer generation programs began in 1999 with the Net Metering program. As of August 2014, 2,019 customer generation systems contribute to the grid, with 98 percent of customers generating energy from solar photovoltaic (PV) systems. The program grew slowly until July 2005. In 2005, the state of Washington implemented the Renewable Energy Cost Recovery Program, which is an incentive-based program where customers with eligible generation technologies are paid for all kWh produced. The purpose of the program is to develop a market for renewable energy systems and to promote the manufacture of these systems in the State of Washington. Incentives are provided from July 1, 2005, through June 30, 2020. PSE administers annual payments to these customers and recovers those funds from state taxes.

This program is also known as Production Metering and along with federal tax credits and falling solar installation costs has helped accelerate the adoption of customer generation. Utility bills provided to customers show both Net and Production Metering. These programs continue to grow, and based on past growth patterns, customer generation systems are expected to reach 4,500 by the end of 2017.

2000

Distribution Automation-Large Customer Campus

In the late 1990s, a large customer requested and paid the incremental cost for a more robust and reliable distribution system. The initial project consisted of installing SCADA switches at a select number of critical campus buildings. The SCADA switches have increased from the original six to 42 switches today. Through SCADA, PSE's system operator can remotely monitor and control the distribution system, and is alerted real-time through an alarm if an outage event occurs. The remote operation also allows the operator to open and close the switches in order to isolate the cable where the outage occurred, and restore power to the rest of the sections.

In the early 2000s, the system was enhanced to a "self-healing" system, again focusing on critical buildings. Over half of the campus SCADA switches are now automated with logic schemes similar to those used for PSE's transmission system automation. The logic schemes use the SCADA data to automatically detect an outage, isolate the problem section and restore power to the rest of the sections without operator intervention.

Transmission & Distribution Intelligence Upgrades

Over the years, PSE has been continually installing three phase reclosers on distribution feeders to reduce the impact of outages; in 2009, a more aggressive program was initiated to improve overall reliability. Additional communications reliability initiatives came online when fiber optics cabling upgrades were made at key transmission substations to increase reliability and meet growing network demand.

Home Comfort Control Pilot

PSE collaborated with three vendors to deliver the Home Comfort Control Pilot (HCC), a pilot to test new technical capabilities, enhance its relationship with customers, and explore platforms for future program offerings. One hundred five customers participated in the proof-of-concept pilot in which software and thermostat control technology was tested for curtailment events triggered by PSE.

Participants, notified of upcoming curtailment events messages on their thermostat screens, could override any event at the press of a button. Participants could also access their thermostats over the Internet to read and reset them. The pilot experiment proved HCC could be feasible and reliable. PSE initiated 41 successful events, setting back the participants' thermostats by 2° F or 4° F for two hours, across a range of morning, midday and evening peak demand time slots. Participants' energy use was measured against a control group of customers, and demonstrated load reduction for both electric and gas heat. There was strong participation in the events, with only 5.3 percent of participants overriding the events. Overrides were concentrated among a few customers.

While the pilot was successful in its proof of concept and customer acceptance, the technology was prototypical and following the project, the participating vendors decided to not commercialize the components. Commercial HCC deployment would have required major resource-intensive work to adapt PSE CIS systems. The equipment was dedicated only to forced-air heating systems, and other appliance control systems would have to have been developed and tested.

PSE.com

PSE launched its website, PSE.com, in 2000. In 2005, My PSE Account was added, which allowed customers to view their statements, leverage home energy tools to download energy use analyzers, see their previous days' energy consumption, and pay their energy bills online, all of which was made possible by PSE's deployment of AMR. Online bill payment was added in 2004, and in 2006, the website provided customers with a single user sign-on enabling them to manage their online payments and access PSE's energy efficiency programs and services and the energy tracker tool.

2001

Time of Use (TOU) Pilot

PSE designed and implemented a TOU pilot with 400,000 customers. The initial phase was the information phase where customers received information about their energy use during four time blocks: morning, midday, evening and economy.

In May of 2001, the second phase was implemented using TOU rates. PSE designed and implemented a TOU rate for its residential and small commercial customers. The rate involved four pricing periods aligned with the four time blocks in the information phase. The morning and evening periods were the most expensive periods, followed by the midday period and the economy period. Unlike most TOU rates, which typically feature significant differentials between peak and off-peak prices, PSE's TOU rate featured very modest price differentials between the peak and off-peak periods, reflecting the hydro-based system in the Northwest.

To keep the rate simple, there was no seasonal variation in prices. The second phase was launched during extreme price volatility, which later would become known as the California Energy Crisis. PSE also had the Conservation Incentive Program in place.

Customers participating in the information phase were placed on the TOU rate plan, with the ability to opt out to the standard rate if they so desired. There was no additional charge to participate in the rate. The rate was designed to be revenue neutral for the average customer. During the first year of the program, less than 0.5 percent of customers elected to opt out of the rate. Customer satisfaction with the rate was high. In focus groups, customers identified several benefits of the TOU rate besides bill savings, including greater control over their energy use; choice about which rate to be on; social responsibility; and energy security. PSE also provided a website to customers where they could review their usage in the four rate periods for the previous seven days.

Later in the year, the pilot was modified to be opt-in, and included a monthly fee to recover the cost to manage the data. With the additional cost, the high price volatility declining, and the price differential reduced to being relatively small, many customers saw little or no savings. As such, the pilot ended in November 2002.

Key lessons learned from PSE's TOU pilot program include:

- Customers do shift loads in response to a TOU price signal, even if the price signal is quite modest. According to an independent analysis, customers consistently lowered peak period usage by 5 percent per month, over a 15-month period;
- It is important to communicate clearly with customers about likely bill savings;
- Consumer education is important, and should be done in a variety of ways. A variety of means were used, including: advertising, letters, refrigerator magnets, a company website that provided a listing of load shifting activities and associated savings estimate, and a personal website to view their usage in the four time blocks;
- While most of the customers initially visited the website to view their usage, use of the Web dropped off early in the program as customers gravitated to simple and easy actions, as suggested by our customer education messaging: turn on your dishwasher after 9 p.m., for example, or do your laundry on Sundays.

Meter Data Warehouse (MDW)

In late 2001, PSE launched a project to implement a MDW. There was a large volume of energy consumption data available that was not being stored or used to its full potential. The MDW initially served as a storage facility for data. Between 2002 and 2008, the system was enhanced to include functions like validation, load profile, service order integration, diagnostic flags, outage, and customer presentment. Tools were also built for ease of use as an enterprise application. In 2010, the MDW was upgraded to a full MDMS, capable of handling the intricacies of a smart grid environment. These intricacies include the ability to accept multiple meter read files daily, enhanced outage reporting for end points and network equipment, read recovery capability, and Web services for real-time applications.

2003

RCM Program/Energy Interval Service

Prior to its adoption of AMR, PSE began offering its commercial and industrial customers the Resource Conservation Manager (RCM) Program. Through the program, the customer tracks and analyzes utility use (e.g., electricity, gas, water, and waste), and identifies potential savings opportunities. PSE offers training as well to assist the customer. The Utility Manager is database software that tracks and analyzes monthly utility data. When the program started, customers initially had to manually enter their monthly utility data. But by 1998, PSE was able to provide digital customer billing data as a service to its RCM customers for import into their Utility Manager databases. RCM customers often track data for multiple accounts or facilities, and many are responsible for hundreds of meters. Providing data in a digital format has enabled them to accurately track the performance of each site, and to identify conservation opportunities.

In 2003, with deployment of AMR, PSE expanded its program offering to include an Energy Interval Service (EIS). In contrast to the Utility Manager software, EIS provides access to 15-minute interval meter readings for compatible PSE electric meters; and hourly or daily meter readings for compatible natural gas meters the day after data is collected. This provides customers with an enhanced ability to track, analyze, and optimize their energy use.

Through this program, PSE supports customers in identifying and targeting low- and no-cost efficiency opportunities that can be immediately implemented in facilities. These generally come from organized behavioral changes, operational improvements and enhanced facility maintenance strategies.

2005

Renewable Energy

Since 2001, PSE has promoted the development of renewable energy through its Green Power Program, which offers customers the option to purchase electricity from renewable energy sources. In late 2005, PSE became the first Northwest utility to build, own and operate a large wind facility. Our Hopkins Ridge Wind Facility in Southeast Washington's Columbia County has been generating power since 2005. PSE's second, larger wind facility, Wild Horse Wind and Solar Facility in central Kittitas County, has been producing energy since 2006. In 2009, PSE expanded the Wild Horse facility and in 2012, completed Phase I of our Lower Snake River Wind Facility in southeast Washington.

2006

Conservation Voltage Reduction (CVR) – NEEA Pilot

PSE originally conducted its first CVR study on ten residential feeders in 1983. In 2006, PSE and 13 other Pacific Northwest utilities participated in the Distribution Efficiency Initiative (DEI) study, convened by The Northwest Energy Efficiency Alliance (NEEA). The DEI study was intended to quantify the effects of power consumption in relation to the applied voltage. Design and operational techniques were used to optimize the performance of a distribution system in order to achieve energy and demand reduction.

The DEI study was comprised of two independent projects: the Load Research Project and the Pilot Demonstration Project. The results of the study conclusively showed that operating a utility distribution system in the lower half of the acceptable voltage range (114-120 Volts) saves energy, reduces demand, and reduces reactive power requirements without negatively impacting the customer. The energy savings results are within expected values of one to three percent total energy reduction, two to four percent reduction in kW demand, and four to ten percent reduction in kilovolt amperes-reactive (kVAR) demand. Computer model simulations showed that by performing selected system improvements, between 10 and 40 percent of the total energy savings occurs on the utility side of the meter.

One of the main objectives of the DEI study was to look at different techniques for lowering the voltage without falling below the minimum acceptable level (114 Volts as defined by ANSI C84.1), and measuring the impact on demand (kW and kVAR) and energy. The Load Research and Pilot Demonstration Projects controlled the voltage for 24 hours (On days), and then the normal utility voltage (uncontrolled) was applied for the next 24 hours (Off days), alternating back and forth for the duration of the project. The actual energy savings for the project was 8,563 MWh, or 1.88 average megawatts (aMW) (8,563 MWh/No. of Hours On). If the DEI projects were in operation full time (instead of every other day) for an entire year, the annualized savings would have been 16,490 MWh.

Mobile Workforce

In 2007, PSE began deployment of ruggedized laptops containing encrypted laptop-resident databases, and using Voice over IP (VoIP) and IP communications in service trucks to allow technicians to digitally record start, stop and status of service calls over a secure virtual private network (VPN).

2009

Plug-in Electric Vehicles (PEV)

Recognizing that PSE's customers would be acquiring plug-in electric and hybrid vehicles in the coming years, PSE incorporated two converted plug-in hybrids into fleet use and is working with several municipal customers and research entities who have done the same. Using data collected from the project, PSE has developed estimates of expected energy needs, performed initial assessment of distribution impacts on select circuits, and performed some tests of effectiveness of curtailed charging. All of these studies determined that initial adoption of electric vehicles and plug-in hybrids would not have significant effects on PSE's energy needs or distribution system. Today, PSE has four demonstration vehicles in its company fleet. We are also participating on the State PEV Task Force and working closely with entities/partners working to site and interconnect public PEV charging infrastructure.

Home Energy Reports

In 2009, PSE began providing home energy reports for 38,000 PSE natural gas and electric residential customers. The home energy reports are designed to motivate and educate recipients to take action to improve their homes' energy efficiency. The reports utilize daily meter reads to provide each participant with a direct comparison of how his/her home energy consumption compares to that of neighbors who live in similar homes. Consumption patterns are analyzed to disaggregate the usage of various systems around the home in order to more accurately guide a customer toward targeting systems that are consuming the most energy.

In 2014, PSE has rolled out the Home Energy Report project to 100,000 customers; with each Home Energy Report containing three key personalized components:

- Comparisons of recent energy use to a group of comparable neighbors, including comparison of the participant's recent energy use to their prior year's consumption;
- Normative messages designed to motivate action;
- Targeted energy efficiency advice that includes specific tips based on the home's energy use pattern, housing characteristics, and household demographics.

Demand Response

PSE's 2007 and 2009 Integrated Resource Plans (IRP) presented achievable estimated demand response capacity potential for residential, commercial and industrial customer sectors. Pilot programs for both commercial and residential demand response were launched in 2008/09. PSE's primary focus was to pilot load control during times of high peak loads, focusing on the customer communication needed, as well as on the information and incentives needed to motivate the customer to respond.

Residential Load Control: While participants were highly responsive to the pilot promotion and recruitment process, total enrollment in the pilot fell short of the original target. Explaining demand response and differentiating it from traditional energy conservation in the minds of residential customers was challenging. As a result of the pilot, PSE found residential direct load control (particularly in a winter peaking climate) was a challenging and complex undertaking, even with the most current technology available.

Commercial/Industrial Load Control: Experience gained in conducting the pilot has greatly facilitated PSE's recent planning and RFP process for a long-term commercial-industrial demand response program. Satisfaction of customers with their participation experience was high. Most indicated an interest in enrolling in a future demand response program offered by PSE. The average event realization rate was 83 percent during winter and 140 percent during summer.

Home Power Cost Monitor Pilot:

In 2009, PSE piloted the use of the Blueline (a third-party provider) Innovations Power Cost Monitor with 1,000 customers. The device works by having an optical sensor attached to the customer's meter to read the meter and wirelessly send a signal to an in-home display. The customer enters the utility rate and is able to see home energy consumption and costs in real time, peak energy consumption in a 24-hour period, and the effects of customer end-uses on energy consumption and costs. While PSE determined that challenges and limitations of this pioneering technology did not make it viable for continued, large scale customer use, customer feedback indicated information provided by the monitor led them to make energy-saving changes or improvements to their home or behavior.

2011

Savings & Energy Center

In April 2011, PSE launched a Savings & Energy Center on PSE.com. This energy-efficiency dedicated section of PSE's website was developed as the foundation for making more sophisticated energy management and self-service tools available to customers online, in support of the PSE's business drivers and customer research. The updated website offers an improved user experience, with more intuitive navigation and new online tools to help customers understand and reduce their energy usage, such as CFL recycling location and efficient product retailer and dealer locator maps, and integrated social media tools and multimedia channels. Additional features include:

- PSE's Interactive Rebate Finder, featuring dynamic rebate and promotion information for homeowners, single-family home builders and multifamily property owners
- Audience-specific subsites with updated content
- "Re-Energize" energy-efficiency rebates and offers splash page
- Fillable sign-up and info request forms
- Home and business energy use calculators
- Energy-efficiency video gallery
- Energy-efficiency events calendar

2012

Conservation Voltage Reduction (CVR)

Successful results of the 2006 NEEA CVR Pilot led PSE to move forward and develop an initial program to analyze 12 substations by the end of 2012, and then implement CVR on three substations by the end of 2013, and three to six more substations in 2014. The results of the 2006 study conclusively showed that operating a utility distribution system in the lower half of the acceptable voltage range (114-120 Volts) would result in reducing electric usage and demand and reactive power requirements on the customers' side of the meter without negatively impacting the customer. The proposed substations were selected mainly for their residential loading characteristics. PSE's participation in the NEEA CVR study showed the importance of a number of "thresholds," which help to assure properly maintained customer voltage levels. These "thresholds" include phase balancing, power factor, and end-of-line voltage monitoring after the CVR settings are implemented to verify the model. Modeling the system and loads as accurately as possible, while understanding the limitations, is an important aspect of successful project implementation.

Energy Management System (EMS)

PSE upgraded its EMS in mid-2012 to meet evolving PSE operational requirements, stay current with existing and future NERC & FERC Cyber Security Advisories, and support future business needs. A core foundational technology for the enablement of smart grid capabilities, this upgrade increased efficiencies at PSE by reducing manual processes and increasing system automation, both of which are improving PSE's ability to avoid and/or quickly restore transmission outages. Additionally, improved network and SCADA model data collection capabilities provide added safety of field crews by enabling better information about the status of grid equipment and devices.

Geospatial Information System (GIS)

As of 2013, PSE has completed its data migration of electric and gas legacy map and service card data into PSE's new GIS system – providing a significant increase in functionality over PSE's previous static mapping system. The upgraded system is the SmallWorld for the Utilities product suite from General Electric. GIS is a core foundational technology for the enablement of smart grid and allows more effective management and control of PSE's gas distribution and electric network. For example, the system provides easier access to network asset location and characteristics, and enables PSE's system to be managed and maintained more safely and effectively. It enables increased network reliability and greater levels of service to PSE's customers.

Remote Data Acquisition Devices (RDADs) Pilot

In 2012, 60 RDADs were installed in 20 switch locations in Bellevue's Central Business District to support a fault detection requirement for the underground network. This technology has the potential to aid PSE System Operators with normal operational switching and allow quicker response to faulted equipment by reducing the need for trouble shooting. As of 2014, PSE has installed 90 RDADs, with 60 located in the Bellevue Central Business District.

2013

Grid-Scale Energy Storage

In 2013, PSE began efforts to develop its grid-scale energy storage capabilities with two projects that will provide working demonstrations of dispatchable stored energy within PSE's service area. The projects are sized at 2.0 MW and 0.5 MW, and scheduled to be implemented by the end of 2015. Energy storage has the potential to assist PSE with shaving peak demand, reducing outages by dispatching stored electricity, and providing system flexibility which can help balance electric supply and demand and ease the integration of intermittent renewable energy generation into the grid. For remote and vegetation-dense parts of PSE's service territory, a key use of energy storage will be as a means of providing backup power during grid outages.

Appendix B

Progress on 2013-2014 Proposed Implementation Plan

(As proposed in PSE's plan submitted to the UTC dated 01 September, 2012)

This appendix provides updates on programs that were proposed in the 2012 UTC report and their status as ongoing projects, completed, or on hold.

✓✓ - Executed on plan	✓ - Pursued plan with some changes	+ - Plan on hold or cancelled for business reasons

Area/Proposed Project Details	**Status**
Information Technology	
Energy Management System (EMS)	
Proposed: Complete Release 2 of PSE's Energy Management System (EMS) **Status Details:** PSE updated its EMS over two releases. The first release upgraded PSE's EMS to a newer version of EMS provided by Alstom Grid to meet evolving PSE operational requirements, stay current with existing and future NERC & FERC Cyber Security Advisories, and support future business needs. This project began in early 2010 and was completed in May 2012. The second release included several upgrades, including extending the EMS network model to include neighboring utilities, implementing a Dispatcher Training Simulator, upgrading user workstations, and adding the "e-terravision" module to provide better situation awareness within PSE's control center. Overall, this project will improve PSEs ability to avoid and/or quickly restore transmission outages, providing customers with shorter outage durations. Costs to complete Release 1 and 2 were $11.1 million (with $10.3 million invested from 2010-13). The scope of Release 2 was expanded to include "e-terravision" within the previously estimated range of $11 - 11.5 million.	✓
Meter Data Management System (MDMS)	
Proposed: Upgrade PSE's Meter Data Management System (MDMS) to the most current version. **Status Details:** The project and budget have been approved, and are scheduled for implementation by EOY 2014.	✓

Project: **Gas and Electric Geospatial Information System (GIS)**	
Proposed: Implement Gas and Electric GIS **Status Details:** PSE implemented a Geospatial Information System (GIS) to assist in the management and control of both the gas and electric distribution networks. This system utilizes GE SmallWorld products, and provides mapping, location and network management functionality for PSE's natural gas and electric distribution networks. All gas and electric network legacy data was entered into the GIS between 2011 and 2013, and the GIS had been successfully interfaced with both the new electric Outage Management System (OMS) and the new SAP Customer Information System. During 2013, PSE implemented additional gas functionality and began capturing additional data. This information includes Cathodic Protection test sites and systems from SAP data, Leaks from the Leak Management System and Exposed Pipe Condition Report data from SAP. During 2014, PSE implemented the first phase of a new map viewing platform which will provide the office and field users access to GIS maps and data. In late 2014 PSE will complete analysis and planning for future releases of this new application. Overall, the total Gas GIS costs are $14 million. The Electric GIS costs are included as part of the total OMS Report Cost Estimate. The Gas and Electric GIS, along with the OMS, will help the company to more quickly and accurately identify and assess both gas and electric outages. With its successful implementation, PSE employees will be able to use data stored in the GIS to query, view, and share asset data company-wide. The company will also use asset data from the GIS to more easily prioritize maintenance projects, efficiently and proactively decide what long-term capital improvements it needs to make to ensure safe and dependable utility service, and coordinate those efforts with upgrades already being undertaken in the field.	✓✓
Outage Management System (OMS)	
Proposed: PSE would install General Electric's OMS (PowerOn) to replace several systems that were nearing obsolescence, or that were inconsistent with PSE's IT strategy. The OMS works to improve PSE's customer service, outage management, data collection and analysis and reliability reporting beyond what was possible with the previous systems and processes. With both the electric GIS and OMS in place, PSE has enhanced capabilities in a number of functions, including: • Improved outage prediction and switching. • Reduced outage durations. • Integration of customer communication channels. • System integration with SCADA so that the system responds automatically to problems detected by sensors rather than manual entries. • Integration with our mobile workforce system. • Integration with our asset management tools so staff is able to track all changes to the network and maintain the data quality of the network. **Status Details:** On April 1st, 2013, PSE went live with OMS as scheduled. The OMS deployment cost approximately $40 million. The system went through a stabilization period from May through the end of 2013, where multiple enhancements and updates were completed to improve functionality and performance, in addition to continued training of staff with the tool and business processes.	✓✓
Customer Information System (CIS)	
Proposed: Replace the CIS application (CLX) with SAP's Customer Relations and Billing (CR&B) CIS package. **Status Details:** The project went live in April 2013, and was stabilized in September 2013. As part of this project, PSE: • Replaced the current, outdated, customized mainframe CIS (CLX) with a modern CIS on an industry standard platform. • Migrated existing CLX data to the new CIS application (1.6 Billion pieces of data loaded to PSE's Business	✓✓

Warehouse, 486 million pieces of data to CIS).Delivered optimized business processes. • Implemented a CIS business intelligence solution which provides PSE near real-time access (including ad hoc access) to CIS data. • Allowed PSE to utilize new and upgraded billing and reporting capabilities. • Laid the foundation for future customer facing smart grid applications. With the full implementation of the CIS package, customers should now experience the following service improvements to PSE's services: • The CIS Project will continue to improve timely and accurate bills, reports, and queries that adhere to regulatory compliance. • PSE targeted higher system up-time. • PSE will not have to rely on third parties for expensive hosting or system modifications. • The new CIS system now allows for more efficient self-service, better reporting capabilities, and faster time to delivery of significant functional changes and improvements. • The new system now allows for increased standardization and automation of processes, enabling greater efficiency and quality control. • The SAP CIS solution is expected to reduce IT maintenance costs and deliver significant business benefits. • Synergies with OMS and GIS will allow outage and safety information to be communicated to customers more quickly and comprehensively.	
Distribution Management System (DMS)	
Proposed: Receive the next integrated product release from GE in 2013; develop a project schedule for the Distribution Management System (DMS). **Status Details:** PSE elected to postpone installation of GE's GENe until its next version release that supports a single OMS and DMS interface.	+
Substation Internet Protocol (IP)	
Proposed: Implement SCADA using IP technology for new or rebuilt substations. Implement SCADA at additional substations, especially those that do not meet NERC Reliability Standard EOP-008-01 requirements. Build out the Operation's Network Distribution Tier. **Status Details:** PSE has had a successful test of EOP-008-01, and has installed and commissioned 54 IP Gateways to date.	✓✓
Advanced Metering Infrastructure (AMI)	
Proposed: Continue to update PSE's business case on deploying Advanced Metering Infrastructure (AMI). Perform targeted pilots to evaluate specific applications of AMI. Develop technology roadmap with accompanying system requirements and architecture. **Status Details:** PSE implemented a 46 meter demonstration of the AMI technology and its impact on revenue billing and voltage monitoring, and continues to evaluate the merits of different AMI deployment strategies.	✓✓
Energy Trading and Risk Management System (ETRM)	
Proposed: Replace Gas Management System and Gas for Power in 2013/14, replace Power Management System in 2014/2015, and implement Integrated Resource Management Analytics in 2015/2016. **Status Details:** The ETRM technology road map and business case have been drafted, though the project was deferred due to integration and funding requirements.	+

Area/Proposed Project Details	Status
Customer Information and Energy Empowerment	
My PSE Web Enhancements	
Proposed: Redesign "My PSE Account" and migrate it into the existing PSE.com. This provides an authenticated user experience, enhancements and additions to a variety of customer self-service features and will enable PSE for future mobile capabilities. **Status Details:** Project completion and go live for this project occurred in 2012. The project is complete, though PSE continues development and refinement of its MyPSE web services. The project costs $1.2 million annually for maintenance and continuous improvement, and realizes the following customer benefits: • Consolidating the technical infrastructures into a single customer-facing experience will reduce the ongoing support associated with multiple technology environments, and allow the leveraging of additional web services transactions. • The project will eliminate duplication of content from the authenticated site, and will enable business units to directly provide content without the IT department's direct assistance. • Web enhancements create an expanded catalog of bill pay capabilities, including paperless bill pay options. • A mobile presence will allow customers to access PSE outage information more quickly. This will enhance customer service and reduce customer care call volumes. • Customers will have the ability to access additional self-service transactions. • Consistent content and branding will be aligned to a single PSE brand. • Better communications to customers will enhance safety messaging.	✓✓
PSE.com Online Tools	
Proposed: Continuous Improvement to PSE.com Online Tools **Status Details:** PSE worked to develop additional tools to help PSE's residential and business customers, community partners and trade allies take even better control of their energy use, and research and testing of capabilities to support PSE's energy-efficiency outreach efforts.	✓✓
Home Energy Report Pilot Program	
Proposed: Home Energy Report Pilot Program **Status Details:** The initial pilot has been completed, and PSE expanded the program to 100,000 customers in March 2014.	✓✓
Net Metering (Distributed Generation)	
Proposed: Expand processes for supporting Distributed Generation customers **Status Details:** PSE's Net Metering program has had an average annual growth rate of 57%, is nearing 2,000 total net metering customers, and continues to build out processes and support for more customers and larger interconnection projects.	✓✓
Plug-in Electric Vehicles (PEVs)	
Proposed: Monitor PEV trends, and use this data to conduct feasibility/impact studies with regard to the vehicles' potential impact on PSE's service area. Utilize fleet demonstration vehicles, and continue to provide interconnection support to customers. **Status Details:** Ongoing efforts have been maintained with respect to PEV studies, and the vehicles have yet to make a significant impact on system operations.	✓✓

Area/Proposed Project Details	Status
Transmission and Distribution Infrastructure	
Transmission Automation and Reliability	
Proposed: Install supervisory control on 115 kV transmission line on Mercer Island. Review existing switching schemes and upgrade or replace aging schemes as needed. **Status Details:** Installed supervisory control on a 115 kV transmission line on northern Mercer Island, automatic controls on two 115 kV lines and supervisory control on another. Restored automatic control on an additional line by adding a second recloser.	✓✓
Distribution Automation – Large Customer Campus	
Proposed: Continue to monitor distribution automation system to determine needed improvements to enhance system reliability to the large customer campus **Status Details:** PSE has and will continue to work to identify and evaluate distribution automation products that will improve the operations and maintainability of automation for PSE and allow for expansion of automation to other areas in our service territory.	✓✓
Distribution Recloser Program	
Proposed: Continue expansion of recloser installation program on overhead circuits. Continue investigating the benefits for reclosers with communications and monitoring capability. **Status Details:** As of June 2014, PSE has installed a total of 583 reclosers on overhead distribution circuits, with 66 installed in the last two years. Six of the reclosers were installed with communication for remote monitoring and control.	✓✓
Distribution Supervisory Control and Data Acquisition (SCADA)	
Proposed: Install SCADA in all new distribution substations. Continue progress to install SCADA improvements at the final 17 substations by 2015, along with new distribution circuit breakers with supervisory control. **Status Details:** To date, PSE has equipped over 99% of its distribution substations with SCADA, with 92.3% possessing three-phase amp readings on all breakers. 22.5% of its substations have supervisory control of some or all distribution breakers.	✓✓
Remote Data Acquisition Device (RDADs) Pilot	
Proposed: Install up to 50 RDADs in Bellevue CBD, evaluate RDAD incorporation into PSE's new DMS system, and deploy RDADs to limited-access parts of PSE's service territory. **Status Details:** PSE now has 96 RDADs installed, with 60 in the Bellevue CBD. PSE's functional test is ongoing, and currently assessing second generation hardware and a web hosting service to gather more granular data.	✓✓
Distribution Automation in Bellevue Central Business District (CBD)	
Proposed: Finalize a solution for SCADA switches in existing vault locations, set new construction standards for future installations, and replace load switches in key locations to manage outage restoration, facilitate automatic switching, and allow further segmentation or isolation of problems. Evaluate and select distribution automation program. **Status Details:** PSE has retrofitted 18 SCADA switches, and is currently integrating their functions into the EMS. PSE is working with the City of Bellevue to refine the long term design and operating principles. PSE also finished installing a fiber optic backbone as well as improved communications equipment and related power supplies at relevant substations.	✓✓
Conservation Voltage Reduction (CVR) Pilot	
Proposed: Implement CVR Pilot on three substations by EOY 2013, and on three to six additional substations by EOY 2014. **Status Details:** PSE has implemented CVR at the program's first three substations on Mercer Island, with ongoing optimization work at one of the three substations. PSE is currently expanding deployment to up to six additional substations by the end of 2014.	✓

Appendix C

Details of PSE's Two-year (2015-2016) Smart Grid Implementation Plan and 10-year Roadmap, Including Descriptions of Smart Grid Technologies under PSE Consideration

PSE regularly considers how new technologies, including smart grid technologies, may contribute positive benefits to its customers and systems. A catalog of these technology considerations would span the industry and its vendors. PSE evaluates certain technologies in more detail, and those chosen as part of PSE's operations are discussed below.

The following plans may be adjusted as we continue to learn from our current activities, our customers' needs/desires, pilot programs, and the industry at large. Our plans are also subject to resource and budgetary considerations, as well as technological changes and capabilities.

Information Technology

To continue to meet utility and customer demands, and to anticipate the future of smart grid, PSE is embarking on a number of projects outlined below. These projects are being leveraged to either build or strengthen PSE's core information systems, while increasing security and reliability of data transport related to the operation, management, control, and monitoring of energy. The benefits of this major undertaking include quicker outage restoration, enhanced customer service and improved billing and payment options. Essentially, PSE has been working to create the foundation to enable smart grid capabilities.

Over the past two years, projects critical to building this foundation have migrated towards completion. These include PSE's upgrades to its CIS, OMS, and EMS systems. PSE is continuing to refine its analysis of options and business values for transitioning from our one-way AMR system to AMI's two-way communication technology. PSE will also continue its transition of telecommunications traffic to Internet Protocol (IP). With these systems in place, PSE has the foundational technology to enable new applications such as fault location, isolation, restoration and service restoration and voltage control for conservation. Moreover, these systems enable the capability to communicate specific information to customers through a variety of mediums like web and mobile devices.

As requirements evolve, PSE will continue to develop its systems architecture to ensure PSE's security, compliance and business requirements are met, and align with NIST interoperability standards. With several core capability projects behind us, including a number of upgrades to our back-end information systems, we expect our smart grid maturity level to significantly increase over the next 8-10 years.

The development and objectives of these core application projects reflect both PSE's requirements and the maturity of vendor offerings. These major categories of information technology initiatives are aligned within a replacement sequence that takes into account which systems are most critical to replace or upgrade first, which systems are nearing the natural ends of their asset life cycles, and which systems deliver the greatest immediate value to our customers and critical business functions. Budgeting, funding allocation, and rate structure constraints and considerations are all equally germane to this assessment process as well.

Finally, PSE's information technology approach to the smart grid requires interoperability for systems, networks, and network end-point devices. With government and industry standards still in flux for both interoperability and security, PSE is taking a step-by-step approach to deploying integrated information technologies to the degree feasible at the time.

Project: Meter Data Management System (MDMS) Upgrade

Project Description (including goal/purpose of technology): The purpose of the MDMS upgrade project is to upgrade PSE's existing L+G MDMS from version 2.8.3 to the most current production version 3.3. The newest version allows the MDMS to be 'Smart Grid Ready' by implementing the Common Information Model (CIM) compliant interface standards and requiring development of point-to-point integrations between MDMS and other applications under development (such as OMS and CIS).

- MDMS version 3.3 provides a robust implementation of the CIM Standard, which is used by the metering and utility industries to eliminate customizations for interfaces between applications.
- CIM Implementation allows CIS integration to provide complete customer data from CIS to MDMS for estimation, billing, and web presentment of customer load.
- Meter Outage events will move more quickly from MDMS to OMS.
- The CIM interface will also allow OMS to run restoration queries back into MDMS and our meter read providers for Restoration Validation.

Accomplishments to Date: The budget and project were approved in Q1 2014.
Note: MDMS upgrade plans were postponed for approximately two years to allow for the necessary upgrade of adjacent systems.

Lessons Learned: PSE has done prior upgrades to its MDMS system and learned that critical to project success is creating detailed vendor delivery and documentation requirements. PSE has also learned to the value of having more detailed test requirements both for its vendor and internally. Finally, PSE is incorporating CIM compliance standards into its system and vendor requirements.

Next Steps: After the two-year postponement, implementation of the CIM project will take place by the end of 2014. In 2015, PSE plans to implement a disaster recovery capability to further enhance the MDMS's reliability.

Total Estimated Costs: $0.8 Million

Benefits:

Dependability:

- The new system will provide enhanced data to the OMS system allowing for quicker restoration response.
- CIM compliance provides for future integration of advanced meters from AMI meter read providers, with minimal integration costs.

Efficiency:

- Customer experience will be enhanced because the MDMS version 3.3 user interface provides a quicker response for meter data queries (from 45 seconds to less than 10 seconds) that enables PSE providing quicker answer to customer billing questions.
- Interval consumption data, (which is not currently available with the existing version), will also be available for users.
- Enhanced analytics for accurate billing and fast exception handling will be available.

Safety:

- AMR messaging that is received by the OMS system will enable field crews to have more up to date information on the status of restorations and energized lines due to customer generation.

Customer Impact: Enhanced data to OMS will allow for quicker restoration response and customer bill inquiry response.

Project: **Distribution Management System (DMS)**

Project Description (including goal/purpose of technology): PSE will implement a DMS to support and improve PSE's activities in both planning and directly operating the electric distribution network. The DMS will provide for direct monitoring and control of network elements in the field, measurement and analysis of power-flow and will provide a significant level of capability for switching automation. The DMS allows PSE to create new internal models for substations, cabinets and other electrical assets within the GIS network model which is integrated with the asset data model in SAP and the electrical data acquired through SCADA.

The DMS will allow PSE to execute switching more quickly while maintaining safety standards. The new DMS also allows power flow monitoring and analysis of the distribution network so that PSE can accurately determine where, when and how to maintain its electrical assets.

Project Updates: PSE had previously opted to delay the implementation of DMS while General Electric was working on significant improvements to their GENe product. In 2014 General Electric announced a new product, called PowerOn Advantage, to be released in 2014 and it will be the next generation software replacing the existing PowerOn and GENe offerings. PSE will revisit the DMS plan for implementation in 2015 and determine the timeline for starting the DMS Project.

Accomplishments to Date: Selection and purchase of the GENe software was completed in early 2011. An initial review of configuration requirements was completed mid-2011. GENe project startup is delayed to allow time for product evaluation due to changing directions from premier vendors in this space.

Lessons Learned: PSE elected to postpone installation of GENe until the deployment of the next release which will allow for a single user interface for OMS and DMS. The delay also allows PSE's users to gain comfort using the new OMS tool implemented in 2013 and will allow GE to further prove stability and interoperability with installations at other utilities. PowerOn Advantage is General Electric's introduction of a new system that supports a Single User interface for both OMS and DMS.

Next Steps: In 2015-2016, PSE will evaluate the 2014 deployment of General Electric's PowerOn Advantage roll-out to their customers. In 2015, PSE intends to lay out a plan forward which may start with a re-evaluation of DMS offerings in the market.

Total Estimated Costs: Additional implementation costs are to be determined.

Benefits:

Dependability:

- Switching load flow analysis will allow for more frequent partial restorations, will shorten outage durations and improve SAIDI metrics and reduce lost revenue.
- Improved asset management and network planning will lead to a reduction in the number of outages in the long term, resulting in reduced outage costs.

Efficiency:

- System recommended clearance switching orders improve the productivity of System Operations personnel and shorten the outage recovery window.
- Switching steps for clearance automatically recorded as the crew executes the plan in the field for documentation and recordkeeping.
- Use of the training simulator mode allows for testing of the viability of alternate system configurations prior to switching operations and improves cold load pickups.

Safety:

- Faster development of switch orders, with safety documents, reference and switch plan library capability.

Customer Impact: The expected benefit to customers of the DMS is that outage frequency and restoration response will be improved.

Project: Substation Internet Protocol Supervisory Control and Data Acquisition (IP SCADA) Enablement Project

Project Description (including goal/purpose of technology): The Substation IP SCADA enablement project enhances the communications method between PSE substations and the Energy Control Center. The IP-based communications method increases the bandwidth over the legacy analog solution by two orders of magnitude and improves the availability of the entire SCADA system. The Project allows PSE to meet the NERC Reliability Standard EOP-008-01, which requires Backup Control Center (BUCC) functionality within two hours. The mandatory compliance date of July 1, 2013, was met. In order to achieve functionality, SCADA from critical substations was delivered to the BUCC. IP communications enables seamless delivery to both the Primary and Backup Control Centers.

This project is ongoing and will continue to consist of several technology upgrades including incremental replacement of the existing analog SCADA communications infrastructure, telecom transport improvements, implementation of fiber isolation, battery backup and battery condition monitoring upgrades, installation of network cabinets, communication shelters, network routers & switches, upgrading the Multiple Address (MAS) master & remote radios, and the installation of a separate computer network to handle Operational data.

New Project Elements: PSE continues to expand IP SCADA through new SCADA additions and major rebuilds.

Accomplishments to Date:

- PSE expanded the IP enablement project beyond the initial 10 (with two included in proof of concept) substations to the 30 additional substations that require EOP-008-01 compliance.
- PSE continues to extend fiber optic cabling throughout its T&D network.
- Hardware and facilities standards were identified, including routers, remote terminal units (RTU), analog-to-IP converters, emergency power systems and new communications structures in 2010.
- Build out of the Operations Network core was completed by the end of 2011 providing a platform for IP delivery.
- Build out of the Operation's Network Distribution Tier in mid-2013.
- Successful testing to meet EOP-008-01 requirements in July 2013.
- PSE has installed and commissioned 54 IP Gateways as of Jan 2014.
- PSE conducted an evaluation of IP Radio technology and developed a maintenance and support model.
    - An initial proof of concept of the new radio technology was completed in 2012.
- PSE used IP SCADA as part of the Snoqualmie generation upgrade project in 2013.
- Developed an IP SCADA business case in 2014 to determine the rate in which legacy SCADA devices are upgraded to the new IP communications protocol.

Lessons Learned: Greater communications and coordination with security, IT, and other PSE stakeholders was necessary for successful implementation and coordination. Additional planning for equipment space was also often necessary, such as establishing additional cabinetry in or small storage buildings at substations.

Next Steps:

- PSE is using IP SCADA as part of the Baker generation upgrade project, which will be completed before January 2015.
- PSE will continue to implement SCADA using IP technology for any new substations (or those with major rebuilds).
- Expand usage of IP SCADA for generation sites:
- By 2020, PSE will implement SCADA using IP technology at substations that are required to meet EOP-008-01 requirements, as well as at substations that require back-up control center communications.
- Develop designs for a lower cost version of IP SCADA for distribution substations to meet less strict performance requirements.

Total Estimated Costs: $23.1 million Capital, plus $315,000 non-Capital expenditures through 2014.

Benefits:

Dependability:

- The system is designed to provide seamless SCADA control to critical substations communications with the loss of the primary Control Center.
- Separation of the Operation's and Corporate IP networks reduces potential impacts and disruptions. This separation also simplifies regulatory compliance by delineating operations traffic from corporate traffic and change control policies.

Efficiency:

- The IP SCADA project will allow for the elimination of traditional RTU equipment in the future, thus reducing the equipment footprint and need for copper wiring (mainly at new and rebuilt substations).
- The new systems will not require manual intervention to facilitate SCADA control from the BUCC.

Safety:

- Using fiber for substation communications eliminates the potential for dangerous high voltage issues between the substation and public networks that exists with copper.

Customer Impact: The substation IP SCADA project will improve PSE's ability to monitor and restore transmission outages.

Project: Advanced Metering Infrastructure (AMI) Evaluation

Project Description (including goal/purpose of technology): The purpose of this project is to fully evaluate the strategic options and associated business cases for deploying AMI technology. Today, PSE has over 1.9 million AMR meters installed that provide automated meter reads to support billing, inform outage and restoration, and enhance customer engagement via a web portal. The AMR system uses meters that do not have the bi-directional communications capability needed for certain smart grid applications. Since PSE initially deployed its AMR system over fifteen years ago, vendors in the AMI space have made great strides in the development of electronic meters, specialized communications chips built into different meters, and meter data software. PSE is currently evaluating the benefits associated with the AMI technology above and beyond the benefits currently being realized through AMR.

High-level strategic considerations within this project include:

- The programs and services that PSE is interested in enabling with the AMI technology.
- The costs and benefits of the technology.
- The system architecture, network topology, interoperability of system components and the direction of the technology standards.
- The impact of cyber security requirements and business continuity requirements on capabilities.
- The obsolescence and end-of-life estimated for the current AMR meter infrastructure.

Accomplishments to Date:

- In 2011, PSE renegotiated its AMR contract with its vendor. This new contract provides several avenues of departure from AMR that will allow PSE the opportunity to migrate to AMI at a pace of our choosing.
  - Since then, PSE modeled the costs associated with several AMI meter deployment scenarios, and has estimated key benefits associated to the implementation of the technology.
- In 2013, PSE implemented a 46 meter demonstration of the AMI technology to gain experience and confidence in using AMI for both revenue billing and voltage monitoring.
  - Of these, 30 single-phase AMI meters are used to monitor voltage on circuits participating in its Conservation Voltage Reduction program. These meters also provide energy measurements used for revenue billing.
  - The remaining 16 meters are polyphase meters deployed at customer premises in downtown Bellevue. The objective of this deployment is to assess improved load profile read performance with AMI meters, as well as automated meter reading for billing.

Lessons Learned:

- Peer utilities deploying AMI systems have provided PSE with a wealth of lessons around customer engagement, technology capabilities, vendor strengths and weaknesses, and deployment approaches. We have noted the customer concerns about RF safety, privacy and meter accuracy with advanced meters, and studied successful approaches to addressing these concerns. PSE has interviewed utilities who have deployed specific capabilities or specific vendor systems to understand their approaches from a technological, economical and regulatory perspective. Finally, PSE has researched successful deployment strategies of several utilities.
- AMI technologies are likely to provide significant improvement for automated meter operations. However, new installation processes around identifying the geo-location of these devices and careful network design will be required to obtain the benefits of the AMI network.

Next Steps: In 2015-2016, PSE plans to determine the strategic direction for the future of our metering system. In 2014, PSE commissioned a review of the AMI business case. Consultants made several recommendations which PSE is pursuing to strengthen the business case. Should PSE decide to implement AMI, next steps will include gathering requirements from internal and external stakeholders and building out the procurement and implementation plans. PSE will continue to refine both its business case on AMI as well as its ability to address technical considerations around migrating to AMI.

Total Estimated Costs: Costs will depend upon the scope and scale of deployment. A full AMI deployment that replaces all of the electric meters and gas modules may exceed $300 million. However, targeted deployments with a more limited scope have considerably lower costs.

Benefits: Ultimately, PSE will be characterizing the benefits of AMI in detail, but currently is aware that AMI has provided the following benefits to other utilities that have deployed AMI.

Dependability:

- Outage and restoration management are enhanced with AMI, allowing utilities to communicate to the meter to confirm restoration.
- The AMI network can be used to enable automation in the distribution grid for smart switching and device control to minimize the impact of planned and unplanned outages on the grid.

Efficiency:

- AMI will provide more robust and higher fidelity data that can be used to enhance or more efficiently execute the service response to customers in the event of a meter issue, power outage or service disconnect/reconnects. Furthermore, AMI can deliver demand response, dynamic rates and enable voltage conservation to more efficiency use energy and capacity.

Safety:

- Data gathered from AMI can provide added safety of field crews by enabling better information about the status of grid equipment and devices.
- The use of remote disconnect switches enhance the safe delivery of services by not putting a field crewmember at risk of electric arc when disconnecting a meter.

Customer Impact: Customers should experience a faster outage response, more accurate and granular information on energy consumption patterns to inform conservation actions, and new choices in products and services enabled by the meter communications. Some customers may experience improved accuracy in billing due to less estimation or due to a faster response to resolution when a meter issue occurs. Customer's energy data will continue to be collected in confidence and only shared with a third party with explicit permission. The impact on customer bills is still under investigation and will depend on the scope and scale of deployment.

Project: **Energy Trading and Risk Management (ETRM) System**

Project Description: The implementation of a new ETRM System will introduce significant operational improvements and automated integration, allowing for increased gas and power portfolio optimization and generation dispatch, regulatory risk reduction, and business risk reduction. Functionality that this project will deliver includes:

- Providing a centralized ETRM for managing the Trading Operation that introduces automated approvals, controls and integration between major systems.
- Automated integration of generation scheduling and energy management systems to ensure optimal economic dispatch of PSE generating assets that is based on real-time information about the portfolio.
- Addressing the technology obsolescence by replacing the Sungard Gas Management System application prior to the vendor's horizon for system retirement.
- Reducing or mitigating the possibility of compliance or commercial points of failure by creating automated checks and balances within the system.
- Accounting process automation for gas and power physical and financial transactions.
- Consolidating redundant information across disparate applications, databases and enhancing data accuracy and transparency.

Accomplishments to Date: The ETRM business case and technology roadmap has been drafted. The team (front, middle, back office, asset optimization and IT) undertook a 14-month formal operational RFP and feasibility process to identify the long term ETRM technology roadmap and develop the supporting business case.

Lessons Learned: The team discovered that there is not a single vendor which can supply an integrated ETRM solution to comprehensively meet all the requirements of the Trading Operation.

Next Steps: PSE is currently awaiting funding approval to support the following phases identified:
Phase 1 – Gas management system and Gas for Power Replacement in 2015-2016
Phase 2 – Power management system replacement in 2016-2017
Phase 3 – Integrated Resource Management Analytics in 2017-2018

Total Estimated Costs: $13.6 - $15 million for the three phases

Benefits:

Dependability:

- PSE expects to mitigate regulatory (NERC, FERC, WECC, & BPA) compliance fine risk exposure, and improve response time and data transparency during a violation response.
- Operational risk exposure will be reduced by decreasing the number of manually supported applications.
- PSE will increase the automation of generation scheduling practices to more efficiently dispatch or displace generation in light of both reliability requirements and market opportunities.

Efficiency:

- Operational controls, approvals, role based security will be automated, making transactions easier to audit.
  The system will provide the Company with the infrastructure necessary to comply with the Dodd Frank derivatives legislation.
- The system will enhance operational efficiency with automated straight-through processing, a skilled knowledgeable centralized IT support team, and provide real time information access to Trading Operations.

Customer Impact: The ETRM system will have an indirect impact on customers by operating generation assets as efficiently as possible.

Customer Information and Empowerment

In the area of customer information and energy empowerment, PSE will continue working over the next several years to initiate or continue pilots that will allow PSE to effectively test the capabilities of new technologies and anticipate customer needs. Growing customer interest in energy management may drive the need for more intuitive energy management capabilities and reporting tools. Two-way automated metering technology can give the customer household energy usage information to make energy decisions, through appliance monitoring and adjustment. Anticipating customer needs and desires will also drive our need to find new solutions for security and customer privacy.

The long-range vision for home automation is that there will virtually be no corner of home living space or home appliances that smart grid won't be able to manage. Characteristics of this "smart home automation" are:

- Smart appliances and thermostats that allow customers to set their energy consumption preferences
- Solar panels that collect energy which can be sent back to the grid and netted against home energy usage expenses
- Home computer access to a Web portal that allows customers to view real-time information on energy usage
- Smart thermostats that can automatically adjust room temperatures based upon communications with the grid—and which can also display to customers what they are currently paying for power per kilowatt hour
- Smart appliances, such as washers and dryers, with on-board computer chips that can sense grid conditions and turn off or on as needed
- Plug-in Electric vehicles that can also act as back-up generators for homes and supplement the grid during peak hours, while they charge during low peak hours at lower costs
- Two-way smart meters that provide bi-directional communications between customers and the utility, and that automate the meter reading process

It will ultimately be up to customers to determine if or how they will take advantage of the levels of automation and energy management that PSE may offer. PSE's goal is to provide its customers with the information and educational resources that equip them to make informed decisions—and to run pilot projects that evaluate consumer comfort levels with new technology in addition to the cost- and quality-effectiveness of the technology itself.

PSE expects that as technologies continue to evolve and our customers and the market present us with new smart grid opportunities, we will review, evaluate and potentially pilot projects or implement activities in the following areas:

- Electric vehicle charging
- Automation, self-healing, enhanced demand response and the ability to integrate traditional and non-traditional energy sources (e.g., wind, solar) into the grid
- Home intelligence/automation
- Energy storage technology
- Customers supplementing the grid with generation and/or storage during peak

On a final note, PSE is sensitive to customer concerns regarding protection of private customer information, and already has a detailed privacy policy to protect such information. As the company continues to evaluate and implement smart grid technologies and various customer-focused components, safeguards for customer privacy and data security will be taken into account.

Project: **PSE.com Online Tools**

Project Description (including goal/purpose of technology):

PSE strategically uses Web-based technologies to communicate information that empowers residential and commercial customers to make smart decisions regarding their energy use. PSE's AMR system provides data for the Web capability that allows customers to view their previous day's energy consumption.

As part of its energy efficiency program, PSE also provides customers with information to help them make cost-effective energy efficiency investment decisions. This information seeks to encourage customers to participate in energy efficiency programs and services while simplifying the process to take action.

Today, PSE uses its website (PSE.com) to communicate with customers, in addition to brochures and bill statement inserts, covering several topics:

- Billing and energy use
- Information on how to conserve and manage energy and information about PSE rebate incentive programs
- Information and education on renewable energy, along with the promotion of PSE's energy-matching programs, which allow customers to purchase all or a portion of their energy from green energy sources
- Opportunities for customers to sign up for on-premise PSE inspections and recommendations on how household and business energy use can be optimized
- Details on low income assistance and/or tax incentives

The PSE website also shows residential and business customers the goals and results of PSE's overall effort to achieve energy performance efficiency. Energy usage reports are provided to customers via the PSE website, with customers being able to access their household or business data in a secure environment. This is similar to the way the Green Button initiative gives customers easy access to their energy usage data. PSE also provides whole building energy usage reports for building owners, operators, and their contractors by signing up through our web-service (MyData.pse.com). Building owners can use MyData to automatically upload their building usage data to Energy Star's Portfolio Manager or simply obtain the data to benchmark their building for their own energy efficiency projects.

Accomplishments to Date:

In 2012 and 2013, PSE invested in the development of additional tools to help PSE's residential and business customers, building owners, community partners and trade allies. These tools aided them to take even better control of their energy usage as well as research and testing of capabilities to support PSE's energy-efficiency outreach efforts, including:

- Development of the myPSE account "Energy Center," with personalized energy-usage dashboards to help customers manage their usage and demand and understand the savings options available.
- Management of a sophisticated customer data and propensity analytics analysis program, to better give customers the information they need and choices they want, and for future use in online merchandising.
- Launch of the Trade Ally section of the energy-efficiency dedicated "Savings & Energy Center," featuring the new Contractor Alliance Network member portal.
- Improvement of the customer-facing online contractor referral process, including the addition of digital signature capability.
- Additional fillable sign-up and info request forms, including sign-up for service via email
- Robust oversight of the email newsletter program, including improved list management, analytic recovery of customer response, successful efforts to increase customer subscriber numbers and an increase in communications frequency.
- Improved content voice and tone; simplification of instructions, navigation and additional user interface improvements to enhance the online experience.
- Development of the framework for new personalized energy management and analysis tools for desktop and mobile.
- Improved and launched our whole building energy usage tool that automatically provides usage data each month via a self-service format.

These capabilities complement the first phase of Web tools and improved website organization and navigation released in 2011 (as outlined in PSE's 2012 Smart Grid Technology Report's Customer Energy Use Information and Feedback section). PSE is currently implementing new, more sophisticated personalized energy management tools which will give the myPSE account 'Energy Center' a major uplift in 2014.

Lessons Learned: Although significant improvements have been made to PSE's public-facing online tools, investment in new features that provide personalized advice by individual account or premise were tabled due to the timing of CIS upgrades. Without these technological upgrades, the information available to customers about their detailed energy usage is limited, and determined by outdated third-party software solutions.

A platform that integrates customer usage data with a user interface and content that can be managed by PSE is a preferable solution, and will allow PSE to provide an online experience that web users have come to expect. Continuous improvement of these tools is necessary as PSE's technology and customer experience expectations evolve.

The MyData web-service is integrated with Energy Star's Portfolio Manager website as required by state law; therefore the architecture of Portfolio Manager's website dictated how our web-service was constructed to some degree. This integration requires ongoing coordinated maintenance with Portfolio Manager website upgrades or changes.

Next Steps: In 2015-2016, PSE plans implement new, more personalized online energy management tools for customers to take better control of their energy use.

Total Estimated Costs: As outlined in the Energy Efficiency Services Conservation Rider Saving Goals and Budgets, the customer online experience development budget for 2013-2014 was $1,588,000. In 2015, PSE plans to invest $671,000 in improving its online tools and services.

Benefits:

Efficiency:

- PSE aims to enable and empower self-service energy management and community distribution networks.

Customer Impact: This project focuses on empowering PSE customers with tools to track and manage their own energy consumption in a way that is both effective and intuitive. These online tools serve as one platform for a wide variety of its customers to make informed energy decisions.

Project: Home Energy Report (no longer a pilot program)

Project Description (including goal/purpose of technology): The Home Energy Report is a low-cost/no-cost behavior-based energy savings project that provides home energy reports to 38,000 gas and electric single family customers. The pilot was launched in the third quarter of 2008 and is still being implemented to test the durability and longevity of energy savings. Beginning March 24th, 2014, an additional 100,000 customers began receiving the reports. PSE customers receive information that compares their household energy usage to energy usage from nearest like neighbors. Home Energy Reports are customized reports mailed directly to PSE customers that help each residential customer better understand their home electric and gas consumption, motivate them to conserve, and provide targeted calls to action tailored to help each customer save money and improve energy efficiency.

A description of some of the report components and their characteristics is listed below.

- 12-month Energy Comparison Report: Combines GIS data with historical energy data to show customers how their energy use compares to other residents who are most like them (i.e., age of house, square footage of house, on their block or in their zip code). This has been proven to be the single most effective piece of information to motivate consumers.
- Targeted Energy Savings Tips: For every season and city, there are simple changes that customers can make to reduce their energy consumption. The tips are targeted based upon a number of factors, including housing data, demographic information (e.g., renter vs. home-owner), and energy consumption patterns.
- Progress Tracker: The Progress Tracker reinforces the positive aspect of energy savings by applauding customers who reduce their consumption, and by assisting customers who are not progressing. This component employs well researched messaging to reinforce norms.

Accomplishments to Date: The initial pilot has been completed, with an expansion rolled out to an additional 100K customer in March of 2014 and a goal of conducting new analyses to measure the impact of the reports with several different demographics.

Lessons Learned: Results for the cost-effectiveness of the Home Energy Report behavior modification energy savings program are favorable. After three years of receiving reports, household are continuing to conserve energy. After year two, approximately 1/3 of receiving households were suspended from the program. After year three, households suspended in year two continue to use less energy than control households, but they use more energy than households that have remained on the program for three years.

Next Steps: Ongoing efforts to measure the effectiveness of the Home Energy Report project deployment will carry through 2015-2016.

Total Estimated Costs: The total estimated annual cost for the project for 2015-2016 is approximately $1.2 million.

Benefits:

Efficiency:

- The goal of this program is to gain knowledge of customer acceptance, energy savings potential, and the cost effectiveness of the pilot program and the persistence of savings.

Customer Impact: Energy savings as customers elect to change their energy consumption patterns.

Project: **Plug-in Electric Vehicle (PEV)**

Project Description (including goal/purpose of technology): The purpose of this project is to ensure that PSE is prepared for, and to encourage the arrival and adoption of mass-market plug-in electric vehicles. There have been no substantial changes to this effort since the 2012 Smart Grid Technology Report. It is important to note that while PEVs have been growing in number in the Puget Sound region, the market is still in its infancy. In January 2014, there were 5,000 registered PEVs in PSE's electric service territory.

Accomplishments to Date: Completed a comprehensive analysis of PEV sales forecasts, energy and peak load impacts, and financial implications.

- Distribution system study is complete and we conclude that impacts are modest.
- Demonstration vehicles are being used in the company fleet (Two Nissan Leafs, two Toyota Prius Plug-Ins)
- PSE is working closely with entities/partners working to site and interconnect public PEV charging infrastructure.
- Participation on the State PEV Task Force
- Participation in the EV Project. Washington State data from the EV Project validated PSE's earlier forecasts for EV loads.

Lessons Learned: PEVs pose minimal impacts to generation and transmission in the short run. Impacts to the distribution system are small but significant, and easily manageable.

- In the long-run, the additional load and margin from PEVs is greater than the costs to prepare for and encourage this market, yielding a positive benefit for customers.

Lessons from the industry:

- PEV rollout by vehicle manufacturers has been slower than expected
- PEV customer adoption has been lower than all forecasts, but it is too early to conclude what the long-term adoption will be. PSE remains optimistic that PEVs will be successful; even it remains a niche market for several years.
- Smart-grid related efforts in this arena still appear premature. Automakers are reluctant to engage in vehicle-to-grid; other tactics to reduce peak load, such as TOU pricing are likely to be more cost-effective in the short-run.

Next Steps: From May 2014 through December 2016, PSE is implementing the Electric Vehicle Charger Incentive Program per electric Schedule 195 and gathering information on vehicle charging locations and load curves that is specific to PSE's customer base. PSE will then compare the information with earlier PEV analyses, PSE's normal system load shape, and renewable resource availability. PSE also intends to compare methods to monitor PEV energy usage, including monitoring through "smart chargers", using PSE's existing meter systems, and vehicle data, if available. In the same vein, PSE will assess the capabilities and compatibility of "smart chargers" as they relate to PEVs.

Total Estimated Costs: Approximately $400,000-$500,000 annually for 2015-2016 for program administration, data collection, and analysis. This estimate does not include incentives for residential chargers as proposed under PSE electric Schedule 195.

Benefits:

Efficiency:

- In significant numbers, the additional load from PEVs can enhance the efficiency and economics of our electric system by increasing off-peak sales when our system has spare capacity. Increasing sales without increasing fixed cost may ease rate pressures.
- PEVs reduce air pollution, particularly in urban areas.
- PEVs reduce our State and country's dependence on foreign oil and can reduce our customer's exposure to volatile gasoline and diesel prices.

Customer Impact:

- PEV customers benefit from lower fuel costs. In PSE's analysis, however, few PEVs are less expensive than a comparable internal combustion and/or hybrid on a total cost of ownership basis, despite substantial State and Federal incentives for PEVs.
- PEV customers benefit from fuel price stability and the convenience of not having to visit gas stations, though they may sacrifice range if driving a pure electric vehicle.

Project: Net Metering (Customer Energy Generation)

Project Description: At the end of 2013, PSE had 1,906 net metered customers. Most of these customers own residential solar PV systems. These customer generation systems have two PSE meters: the service meter which measures electricity both from the grid and to the grid; and the production meter which measures output from the system in AC. This project aims to ensure that customers are interconnected while meeting standards for safety and reliability.

Accomplishments to Date:

- PSE's Net Metering Program has grown approximately 57% each year over the last 10 years, and it crossed over the 2,000 customer mark in 2014. All systems that can feed electricity into PSE's distribution network are known and mapped by location, technology and capacity.
- New customer interconnection processes improvements for systems less than 100kW have been made to simplify customer applications and interconnection.
- Application and interconnection process improvements for 100kW to 5MW projects continue to be ongoing.
- In 2013, PSE implemented new billing software that automated all aspects of Net Metering billing.

Lessons Learned: As the number of customers grows, the need for automation and reduction in unnecessary regulation/costs grows. In 2013, PSE implemented new billing software on SAP that automated all aspects of net metering billing. Prior to this upgrade, every monthly bill of the net metered customers had to be pulled and adjusted by hand. One of the lessons learned is that with automation, which is a significant step forward, PSE employees are not examining every single bill on a monthly basis. While this saves money, the unforeseen downside is that we no longer have employees actively watching for billing issues. Although rare, we need to implement more sophisticated ways of catching instances when customer electricity production stops or if a bill stops in the system. We continue to assess methods to automate problem detection for net energy billing.
During outages, crews are expected to lock out each known system individually. In 2013, there were also new regulations put in place for disconnect switches that required some training revisions.

Next Steps: Changes being implemented for 2014-2015 include moving to net meters that come directly from the factory ready to net meter. PSE no longer "upgrades" them at PSE, which saves time and overhead. On the program side, we are implementing easier interconnection forms, and we have the 2014-2015 goal of moving our solar generator database into a company-wide system. This will make customer generation visible across the company and it will keep customer information up-to-date. 2015 projects include moving to on-line applications and exploring AMI net metering. This has the potential to address issues like remote disconnection. It also will solve some of our expenses for commercial net metered accounts.

Estimated Costs: To accommodate growth the company is looking at less expensive meter solutions, and more automated ways to "onboard" and accept new projects.

Benefits: Most of the discussion of solar PV distributed generation's impact on the local distribution system is theoretical. Knowing the location of solar PV distributed generation systems, down to the circuit, allows us to determine the real effects as the capacity grows. This will allow upgrades to be made with better knowledge and better results.

Customer Impact: In general, PSE's efforts to improve its own efficiency in facilitating distributed generation benefit the customer. We continue to look for cost-effective means to prepare for and manage a mass adoption of solar PV distributed generation systems.

Transmission and Distribution Infrastructure

PSE’s T&D systems form the backbone of reliable energy delivery to customers, and must be made “smarter” to deliver the types of communications and services that customers expect. Critical factors considered in our two-year and future plans include:

- Upgrading and replacing aging T&D infrastructure and components, as well as supporting IT hardware and end-use systems, for greater system reliability and efficiency, and interoperability with future smart grid applications
- Updating or installing smarter components to accommodate new sources of renewable energy as they are integrated into the system, as customers adopt more renewable technologies, or as technologies change and others become outdated
- Managing the changes proactively with employees and with our customers, to ensure new and enhanced delivery systems are introduced seamlessly
- Planning, managing and deploying new technologies and solutions in a manner that is cost-effective, cost-efficient, and sensitive to the impact on energy rates
- Addressing the increasing (and changing) regulations under NERC, the organization which enforces regulations for the reliability of the bulk power system in North America, as they influence PSE’s services.

Project: Transmission Automation and Reliability Program

Project Description (including goal/purpose of technology): Incremental improvement of the smart transmission system through replacement of aging infrastructure and technologies, and addition of new smart grid functionality of monitoring, remote operations and control, and automation, based on benefits and costs, and available funding. Automatic transmission switching schemes enhance system reliability and protection under different operating scenarios. Automatic switching sectionalizes and isolates faulted sections of transmission lines in order to restore service to distribution substations. When used in conjunction with supervisory control, automatic switching assists the System Operator's in quickly determining the faulted line section and to mobilize crews to make repairs. Supervisory control enables the System Operator to continuously monitor the status (open or close) of the switches and to be able to remotely control their opening and closing. Automated switches with supervisory control have laid the groundwork for improved system reliability on the transmission system over the past thirty years. These legacy control schemes need updating or replacing due to load growth, transmission system changes, or degrading components.

Accomplishments to Date:

2012: Installed supervisory control on a 115 kV transmission line switch located on the north end of Mercer Island.

2013: Installed automatic controls on two 115 kV transmission lines. Installed supervisory control on a 115 kV transmission line switch. In another part of the service territory, PSE restored automatic control on a line by adding a second recloser on an adjacent substation circuit breaker. The new (Bellingham) scheme was made operational in first quarter of 2012, and continues to be tested.

Lessons Learned: It can take a long time to install and/or replace automatic and supervisory controlled transmission line switches. The length of time can depend upon several factors, such as planning and coordinating transmission line outages to minimize risk to the transmission system. Installation times can also be affected by the need to coordinate potential outages with customers to minimize risk of a service interruption. For example, in the case of the 2011 Bellingham line project, PSE worked with an educational institution to align some of this work with the school's winter break.

Next Steps: PSE continuously reviews its transmission system for new automatic switch scheme opportunities, opportunities to improve existing schemes, and any needed upgrades or replacements of aging schemes. One or two new schemes or improvements of existing schemes are typically planned to be completed each year.

Total Estimated Costs: Annual project costs can depend on the number of improvements PSE undertakes in one year, and are estimated at $250,000 - $1.5 million annually for 2015-2016.

Benefits:

Reliability:

- Automatic control of transmission line switches reduces customer service interruption duration times.
- Supervisory control of transmission line switches enables better situational awareness for the System Operators, as they can readily identify whether a switch is open or closed, and also provides them with remote control of the switches.

Customer Impact: Customers served by a substation with automatic control can expect an outage reduction from 60 minutes or longer without automatic control to less than a minute with automatic control, if they are located in an unfaulted section. The 60 minutes is the estimated time it takes to become aware of a problem, send a service lineman out to do a patrol, visually identify and communicate the problem back to the System Operator, and then to actually do the switching to isolate the faulted line section.

Project: **Distribution Automation – Large Customer**

Project Description (including goal/purpose of technology): Distribution Automation technology works to improve service reliability through Fault Location, Isolation and Service Restoration (FLISR).PSE is working with an existing customer to utilize automation enhancements to ensure a greater degree of reliability.

As reported in 2010, there are still 42 SCADA switches supporting this large customer. Expanding the number of SCADA switches by three in 2014-2015 is a strong possibility, though the project is dependent upon the customer's requirements and budget considerations.

Accomplishments to Date: 42 SCADA switches are operational with over half of them pre-programmed with an automated restoration scheme that has been coordinated with the customer.

Lessons Learned: The programming for the "self-healing automation" is more labor intensive than PSE originally planned. Additionally, the self-healing automation programming is not very flexible in making changes when changes to the overall system are made. There are now more solutions in the marketplace that can adjust system configuration changes more efficiently.

Next Steps: In 2015-2016, PSE will be reviewing and evaluating DA solutions for this customer's requirements and for subsequent application in other areas of our service territory. PSE is working to refine its target deployment schedule.

Total Estimated Costs: The customer is currently evaluating the cost for adding three more SCADA switches with the load expansion of two more buildings. All of the upgrade costs for SCADA and automation have been paid for by the customer requesting this capability.

Benefits:

Efficiency:

- Distribution Automation provides real time loading of sections of the circuits with SCADA, which gives Planning and System Operations staff valuable load information for capacity and planning decisions.

Dependability:

- The SCADA in conjunction with automation can automatically detect an outage problem, isolate it, and restore power to the rest of the sections without operator intervention.

Customer Impact: When outages occur on circuits feeding this customer, PSE is able to isolate the fault and reroute the power through other feeds using this automation scheme. The restoration of power to the customer is completed in less than 5 minutes. Without such automation, the restoration could easily exceed 2 hours.

Project: Distribution Recloser Program

Project Description (including goal/purpose of technology): Most utilities pursuing significant reliability improvement on the distribution system, including PSE, install three phase reclosers on the distribution system. Reclosers interrupt faults and re-energize the line after a short waiting period. If the fault is temporary, this will allow the cause of the fault to be eliminated. If the fault is permanent, the recloser will “lock out” and remain open after a preset number of operations. These devices dramatically reduce the impact of outages to customers on the feeder by avoiding the station circuit breaker locking out and interrupting service to all the customers on the feeder. With reclosers installed, fewer than half of the customers served by the feeder will be impacted by an outage.

At present, PSE has about 568 reclosers installed on its system. In 2009, PSE initiated a Distribution Recloser program to install more reclosers on the system with the goal of having at least one recloser on every overhead circuit where customers would benefit from the installation. Most of these reclosers operate autonomously in response to sensed conditions and have no remote monitoring or control capabilities.

In addition, PSE will be evaluating and piloting line reclosers with remote monitoring and control capabilities. Nine of the 568 reclosers on our system were installed with SCADA control and monitoring. These nine will help determine the challenges and benefits of using the recloser as a device as part of distribution automation. It is anticipated that outage duration will be reduced for customers when PSE’s System Operators can remotely operate the reclosers.

Accomplishments to Date: At the end of 2013, PSE had installed 568 reclosers on our overhead distribution circuits. During the past two years from 2012 to 2013, 51 additional reclosers were installed for about $2.55 million. Six of the reclosers were installed with communication for remote monitoring and control. An additional 40 reclosers are planned to be installed by the end of 2014.

Lessons Learned: The installations of reclosers have helped reduce outage duration from some customers. The biggest challenge for reclosers with communication has been communications feasibility. Future projects should have a feasibility review by PSE’s Telecommunications Department to do a site survey and determine the best communications solution for the site. From an operations perspective, PSE recognizes the positive impact SCADA control of reclosers has on its system, and further consideration may be needed on how to integrate these and other SCADA-enabled devices into the new Outage Management system.

Next Steps: In 2015-2016, PSE will continue the expansion of the recloser installation program on overhead circuits. PSE will also continue investigating the benefits for reclosers with communications and monitoring capability.

Total Estimated Costs: Approximately $2.5 million was spent from 2012 to 2013 to install reclosers on the overhead distribution circuits, and PSE plans to spend approximately $1.55 million per year in 2015 and 2016 to continue its recloser installations.

Benefits:

Reliability:

- The outage duration for some customers will be reduced with the installation of the reclosers.
- For the reclosers with communication, the anticipated benefits include faster response time and restoration time due to instantaneous notification of recloser operations, and the ability to restore an outage remotely after the line has been patrolled and cleared.

Dependability:

- There are planning benefits due to the information received which provides three-phase ampere data at a location on the circuit, which allows for better system modeling and decision making.

Safety:

- Safety benefits may be achieved by allowing System Operations to turn off reclosing and activate the Hot Line Work Switch (HLWS) for system work, or even open the recloser for an emergency situation.

Customer Impact: The outage duration will be reduced for some of the customers on the OH circuits with reclosers.

Project: Distribution SCADA Project

Project Description (including goal/purpose of technology): Supervisory Control and Data Acquisition (SCADA) is a system used to monitor and control substation equipment. Key information, such as circuit breaker status and transformer loading, can be obtained and transmitted to PSE's Control Area operations center almost instantly. With SCADA in the substations, crews do not need to be on site to obtain information. During storms and other outage events, this instant access to circuit breaker status (open or closed) speeds restoration efforts and reduces inefficiencies. In addition to circuit breaker status and transformer loading information, PSE's implementation of SCADA often includes the following:

- Monitoring the individual phase loading of the distribution circuits. This information is very important in order to maintain proper load balancing. Since this information is logged and stored on computer systems, it can be used for system planning studies, such as load analysis and simulation modeling.
- Automatically integrating reactive power control at substations that have shunt capacitor banks. This can reduce system losses and reactive power penalties paid to BPA.
- Adding automatic status and control to the 115 kV transmission switches that are typically on either side of the tap or "loop-through" going into the substation. When the 115 kV transmission line faults, the damaged section of line can be isolated by automatically opening a switch, restoring service to substations in seconds.

Accomplishments to Date: PSE has been installing the SCADA system in the distribution substations over the years to better monitor substation equipment and its distribution system. 99% of PSE distribution substations have SCADA, 92% have three phase amps, and 23% have supervisory control of some or all distribution breakers.

Lessons Learned: The 24/7 data reported from SCADA provides system planners with information used for everyday planning – not just peak-load related planning. This information is used for load, reliability and outage studies.

Next Steps: For all new distribution substations, PSE is installing SCADA to operate and control substation equipment as well as monitoring the equipment. By the end of 2015, these SCADA improvements will have been made at 17 additional substations. New distribution circuit breakers with supervisory control will also be installed at these stations.

Total Estimated Costs: Costs have averaged $1.8 million over last three years

Benefits:

Dependability:

- Projects funded by this program are identified with an overall benefit of improved system reliability through a reduction in outage duration and improvement in SAIDI.

Customer Impact: Customers will experience improved reliability.

Project: **Remote Data Acquisition Devices (RDADs) Pilot**

Project Description (including goal/purpose of technology): The purpose of this project is to remotely determine the status of the distribution system through the use of fault sensors. RDADs report back to the system operator every day with hourly load data and daily peak load to aid in normal switching operations, and help System Operators determine where a fault occurred. This will aid PSE System Operators with normal operational switching and allow quicker service response times to faulted equipment by reducing the need for trouble shooting.

Accomplishments to Date: PSE evaluated the first generation of Cooper Fault sensors, but found they did not capture meaningful data that could be used for planning and operational purposes. Cooper Power Systems took PSE's input (as well as input from other utilities) and developed a second generation of sensors that give hourly snapshot load readings. They also integrated Verizon technology into the units, allowing PSE to work with our current preferred communications provider.

PSE has determined that the second generation RDADs could be supported by its EMS. The decision was made not to connect to the PSE system until the new DMS system is developed, and an alternative solution to use Cooper's Web hosting product was examined and selected. PSE currently has 96 first generation RDADs installed, including 60 in the Bellevue Central Business District.

In 2014, Cooper redesigned the RDAD to allow remote configuration via direct DNP3 communications, which will have the capability to give current information in higher resolution. The device uses newer cellular technology that should allow it use in more of PSE's service territory. Cooper is also developing Grid Advisor software that will allow PSE to manage both existing and new RDADs efficiently.

Next Steps: PSE is evaluating additional RDAD deployments, and is assessing which communication protocol would be the most efficient mode for a potential expanded deployment. PSE is also developing a roadmap to connect these devices directly into System Operator's tools for daily use, completing the original vision for this project.

Total Estimated Costs: $3,500/year for the existing system for 2015-2016 and an estimated one-time cost of $125,000 to integrate the next generation software into PSE's processes.

Benefits:

Efficiency:

- The RDAD installation program will help optimize PSE's distribution system with load data on various segments of the feeder system.
- It will also reduce the duration of a circuit outage by reducing the amount of equipment to be inspected.
- This equipment is used in existing switchgear without any additional visual impact to the customer's site.

Project: **Distribution Automation - Bellevue Central Business District**

Project Description (including goal/purpose of technology): To serve areas with very high density loads, many switches need to be placed in close proximity to each other in the sidewalks along busy streets or in parking garages. To perform normal or emergency switching requires servicemen to access vaults under sidewalks with high foot traffic. The purpose of this project is to install Supervisory Control And Data Acquisition Control (SCADA) infrastructure in distribution switch gear located in such areas. PSE has completed its original pilot to replace the seven manual switches for two circuits within the Bellevue Central Business District (CBD) with SCADA switches, and connect them to the EMS system via fiber optic cables. PSE has moved forward to install additional SCADA switches using the following priorities:

1) Replacing reliability switches so that system operators can "see" in real time the status of distribution systems that serve as backup.
2) Installation of the first load switch for each circuit.
3) Installation of other load switches at key locations to further sectionalize the circuit.
4) Where the installation of a SCADA load switch is in close proximity to a reliability switch or other project, in order to do the work in conjunction.

Once the SCADA project is substantially complete and the system is fully operational, PSE will implement an automation control system that will analyze site data, isolate problems, and restore electricity to customers.

Accomplishments to Date: By the end of 2013, PSE completed the retrofit of 18 SCADA switches; 9 of which are fully functional in EMS. The remaining 9 are expected to be completed by the fourth quarter of 2014. The fiber optic backbone system has been completed with connections to both North Bellevue and Lochleven Substations. At both substations, the locations for communications equipment and a power supply have been designed and installed to meet the project needs.

PSE investigated and specified an IT communications solution that meets network security requirements for field devices and will function for all known automation applications. PSE has also developed a Distribution Automation (DA) requirements document and begun outlining a road map towards a system-wide automation solution.

Lessons Learned: The need to place the SCADA switch control enclosures in an accessible location close to the distribution switch. Additionally, continued coordination with City of Bellevue planners and property owners is essential to making the site retrofits sites feasible.

Next Steps: PSE will next prioritize the replacement of switches in the downtown Bellevue “reliability ring” to monitor unloaded back up circuits for the management of outage restoration. By 2015, PSE will proceed with retrofitting six to ten switches to facilitate remote switching, and plans to install five to six additional switches as part of New Customer Construction (NCC) Projects in the Bellevue CBD in 2014 and 2015. PSE will also work to evaluate and select an overall distribution automation program that can be applied to Bellevue CBD and other locations.

Total Estimated Costs: $1.5 – $2 million annually for 2015-2016.

Benefits:

Efficiency:

- Much more real time distribution information is made available to operations and planning to optimize system performance.

Dependability:

- Reduce outage durations by restoring customers remotely and ultimately automatically.

Reliability:

- Due to both the automation and remote control capabilities, PSE expects to have less impact on traffic in downtown Bellevue, as each site will not need to be visited by a service lineman during outage events.

Customer Impact: Customers will experience quicker restoration response as restoration actions can be taken remotely or conducted automatically.

Project: Conservation Voltage Regulation (CVR)

Project Description (including goal/purpose of technology): Conservation Voltage Reduction (CVR) is the practice of lowering the feeder voltage at the substation and line regulators in order to conserve energy on customers' side of the meter without impacting the customers. PSE traditionally has set the feeder voltage within the mid- to higher- range of the American National Standard Institution (ANSI) standard. However, a study completed by the National Energy Efficiency Association (NEEA) in 2007 on two of PSE's substations and eight other regional utility substations has confirmed the economics of implementing CVR where the feeder loads portray particular characteristics. This has led PSE to move forward and continue to implement CVR on six substations in 2014 and three to six more substations in 2015. The 12 proposed substations were selected mainly for their residential loading.

Accomplishments to Date: By the end of 2013, two of three of the Mercer Island substations had CVR implemented on them, and the third had a majority of the work completed. The implementation on the Mercer Island substations involved a system analysis using the system modeling tool, SynerGEE, phase balancing, installation of a pilot AMI system to monitor the end of the line voltage, adjustment of the Load Tap Changer controller and system monitoring.

As of February 2014, PSE has selected three substations for analysis. The forecasted schedule is to complete the analysis, implementation, and documentation of the energy savings by the end of the year for the selected substations of 2014.

Lessons Learned: PSE's participation in the 2007 NEEA CVR study showed the importance of a number of "Thresholds" which help to assure properly maintained customer voltage levels. These "thresholds" include phase balancing, power factor, and End Of Line (EOL) voltage monitoring after the CVR settings are implemented to verify the model. Modeling the system and loads as accurately as possible while understanding the limitations is an important aspect to successful implementation of the project.

Other lessons learned revolve around monitoring the system and making adjustments to the CVR settings as needed to ensure our customers continue to receive great service. Using AMI infrastructure for the end of the line metering proved to be a suitable method for EOL voltage monitoring. However, as the business case for AMI within PSE is developed, PSE is considering other CVR metering solutions for the interim.

There were a few scenarios with implementing CVR on the Mercer Island substations where a customer with an abnormally long service or a heavily loading transformer noticed the lower operating voltage. The solution for this is to either upgrade the service transformer to a larger one or connect the customer to a closer transformer. Overall, implementing CVR on Mercer Island substations has verified the benefit of phase balancing and the need for system monitoring.

Next Steps: PSE will continue the analysis of the six substations, finish the implementation of CVR on three to six substations by the beginning of 2015, and apply lessons learned from their deployment to 2015's CVR roll-outs.

Total Estimated Costs: $500,000 to $1,000,000 (two-year budget for 2015-2016).

Benefits:

Dependability:

- Applying the CVR-specific method of Line Drop Compensation (LDC) will minimize the End of the Line voltage fluctuations, as well as generally decrease the system Volt Ampere Reactive (VARs).
- Phase balancing improves the health of the system by decreasing neutral current and minimizing losses.

Efficiency:

- Implementing CVR will improve the efficiency of selected distribution circuits by reducing line voltage at a distribution substation before energy is sent to customers, thereby creating conservation savings on the customers' side of the electric meter. PSE will benefit from improving distribution efficiency by receiving energy savings, decreasing the peak demand, and the decrease of system losses.

Customer Impact: Customer energy consumption will decrease and the savings will be realized on customer bills. The lower voltage should go unnoticed by customers since it is actively monitored and maintained within the ANSI standard.

Project: Grid-Scale Energy Storage

Project Description (including goal/purpose of technology): PSE intends to develop a 2.0MW/4.4MWh grid scale energy storage system. The purpose of this project will be a working demonstration project for dispatchable energy grid-balancing, outage mitigation, and other key services related to grid reliability and operation. This project will set the foundations necessary for storage to enable PSE to effectively integrate additional renewable generation resources at a lower cost. It will also build the capability for PSE to automatically dispatch the system from PSE's control room.

PSE is considering three potential sites for construction, including a site called "Glacier-12" site, where the energy storage system could be combined with a small run-of-river hydroelectric generation facility to create a micro grid that will provide backup power to the town of Glacier.

Additionally, PSE is working to develop a smaller 0.75 MW energy storage project as part of a Bonneville Power Administration Technology Innovation Project. This project is currently underway.

PSE is also working with Snohomish PUD to develop a standard called Modular Energy Storage Architecture. This effort is focused around building out a standard within the energy storage supply chain for simpler and more economic cross-utility integration.

Accomplishments to Date: In 2013, PSE completed a feasibility and cost-effectiveness study for an energy storage project in partnership with Pacific Northwest National Laboratory (PNNL), and issued a publically available report. PSE subsequently committed to develop a 0.75 MW project that is currently going forward with funds committed for system installation, basic testing, and operations.

For the 2MW system, PSE has selected its engineering, procurement, and construction contractor, and is performing detailed feasibility analysis and finalizing site selection.

Lessons Learned: From the study with PNNL, PSE learned that energy storage appears to be cost-effective in certain distribution system applications when multiple value streams (outage mitigation, peak shaving, and system flexibility) can be combined and realized.

While the 0.75 MW project is important as a test-bed for building expertise with grid-scale energy storage, its relatively small size limits its potential grid impact. PSE is still in the early stages of valuable learning experience regarding the actual capabilities of storage and the real world complexities of attempting to capture the aforementioned value streams.

PSE has been following the energy storage industry closely, and has noticed that prices are dropping more rapidly than expected, with projects are scaling up to the multi-MW class with reputable developers such as AES Energy Storage. PSE is also following California's energy storage mandate closely.

Next Steps: PSE will continue to develop both energy storage projects. Depending on the pace of development, PSE would start the 2.0 MW grid scale energy storage system project in late 2014, and be operational by the end of 2015. Additional operations and functions are planned to be implemented between 2015 and 2017. The 0.75 MW grid scale energy storage system project is expected to be complete by the beginning of 2015.

Total Estimated Costs: PSE estimates a total project cost of $9.5 million for the 2.0 MW grid scale energy storage system project and $1.2 million for the 0.75 MW grid scale energy storage system project.

Benefits:

Dependability:

- Outage mitigation. The storage system will be used to provide backup power during outages.

Efficiency:

- Distribution peak shaving. Shaving peaks on the distribution system can potentially delay the need for expensive capacity upgrades.
- System peaking. By dispatching the storage system like a small peaking plant, PSE may defer the need for new generation capacity.

- Flexibility/Ancillary services. By injecting and withdrawing power from the grid, energy storage can help balance supply and demand, which becomes increasing necessary with increased penetration of renewables. This service can also reduce wear and tear on other generating units that are used for this service.

Customer Impact: The energy storage projects are initially designed to support either remote areas with frequent line outages or distribution systems that are currently overloaded. Through the use of grid-scale energy storage, PSE aims to enhance the reliability of these communities through an "islanding" capability in the case of rural communities. In the event of a transmission-related outage, the stored energy will act as a short-term backup, providing 2-6 hours of electricity while the downed line is being service.