Puget Sound Energy

2012 Smart Grid Technology Report

September 1, 2012
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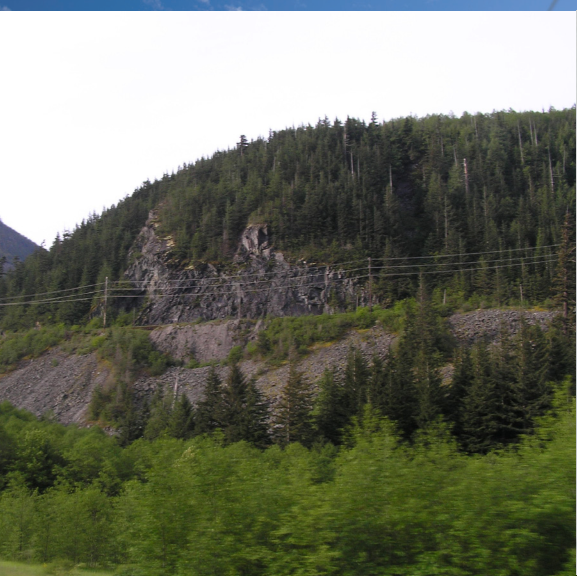

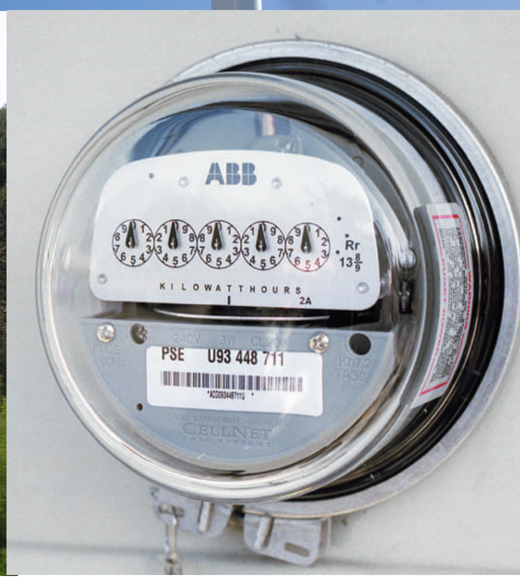

PUGET SOUND ENERGY

Executive Summary

In 1998, when Puget Sound Energy (PSE) began implementing automated meter reading (AMR), few were talking about "smart grid." At 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 an automated transmission system over three decades ago, it was driven by the need for enhanced real-time monitoring and system visibility 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.

Currently, 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;
- More than 1,200 residential customers have grid-connected solar and wind systems allowing them to generate their own power and supply excess energy back to the grid;
- Automated transmission and distribution (T&D) systems improve service reliability; and
- Our new or upgraded back-end systems (EMS, OMS, GIS, etc.) are building the foundational core of smart grid enablement making a major improvement in data reliability and transport.

The Renewable Energy Center at PSE's Wild Horse Wind and Solar Facility in Kittitas County

The smart grid future promises the 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 to the T&D system, to the meter and into the customer's home or business. In concept, this "system of systems" will be more efficient and cost-effective, replacing or integrating multiple stand-alone systems. It will also be more streamlined, enabling data to be accessed for multiple uses across the organization. The customer experience will be enhanced through improved system reliability and customer energy management data and tools. Operational efficiency will also be enhanced through enablement of advanced monitoring, modeling, control and automation of the T&D system, resulting in improved customer service and safe operations.

Each energy company will migrate to this future in a different way. For PSE, our smart grid vision and implementing smart grid technologies continue to evolve. It involves building upon and leveraging our existing investments, as well as our experience, in a careful and 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 upgrade, integrate and install key foundational information technology (IT) systems to enable smart grid capabilities. For example, PSE is implementing a new customer information system (CIS), outage management system (OMS), and geospatial information system (GIS), and upgrading 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 will also have the foundational technology to explore new applications like remote disconnects/reconnects for electric customers when smart meters with two-way communications are deployed. 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, consideration will be given throughout 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, provide 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:

- 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 the operations network and implement additional security and reliability of operations data transport (as needed);
- Work with customers on the development of 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 through automation to improve electric system reliability;
- Evaluate energy storage technologies and potentially deploy specific pilot projects; and
- Evaluate and selectively deploy demand response pilots/programs and other customer energy capabilities.

A PSE Nissan LEAF

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

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Introduction

Smart grid refers to an improved electricity supply chain that runs from a power generating facility all the way to the end-use or application of electrical energy inside a residence or a place of business. A fully developed smart grid employs modern technology to enhance and automate monitoring, analysis, control and communications capabilities along the entire electricity delivery chain. The ultimate goal of smart grid is 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 a follow-up to Puget Sound Energy's 2010 Smart Grid Technology Report, and updates PSE's approach to smart grid deployment, as well as our plan for achieving a smarter system that benefits our customers and our utility operations.

This report is divided into the following sections:

- Background – working definition and vision of smart grid, benefits to customers and utilities, 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 2011-2012 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 rules.

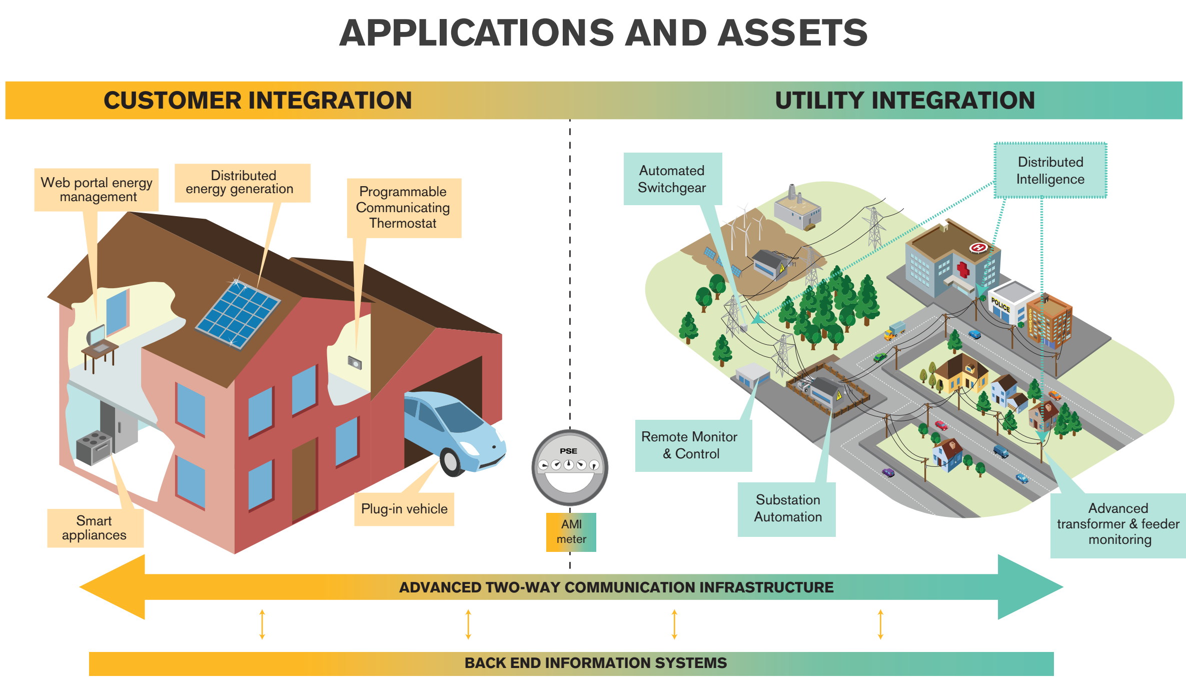
Background

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. The term smart grid relates to many different technologies and systems that are part of the grid, and is deemed an opportunity for the future.

Consider an electric grid that is supported by a safe, 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 optimization of system capabilities and energy utilization.

The following 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, all of which are expected to benefit both customers and utility operations. These communication and control systems provide added abilities, efficiency and flexibility to the electric grid.

Figure 1: Illustration of Potential Smart Grid Applications and Assets



While an end-to-end smart grid with monitoring, communications and control built into all levels as illustrated in this graphic does not yet exist in its entirety, the major components are known. A smart grid can be broken down into three major parts:

- The back-end information systems, also known as smart grid enablers, 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, which is the conduit that 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); and
- 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, and those that manage the utility's assets, such as devices located at substations, switches, capacitors and other distribution system locations that enable automation.

By integrating an end-to-end, advanced communications infrastructure into the electric power system, a smart grid promises to deliver greater reliability because of reduced outages; the potential to reduce the cost of electricity by efficiently being able to balance energy supply and demand; new possibilities for products and services that businesses and consumers do not have access to today; improvements in environmental quality as customers gain access to more renewable energy choices; and an enhanced ability for customers to self-manage their energy consumption.

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

The growing national interest in smart grid (fueled by a multibillion-dollar national investment in smart grid projects currently being implemented and tested [details at smartgrid.gov]) prompted the need for standardization.

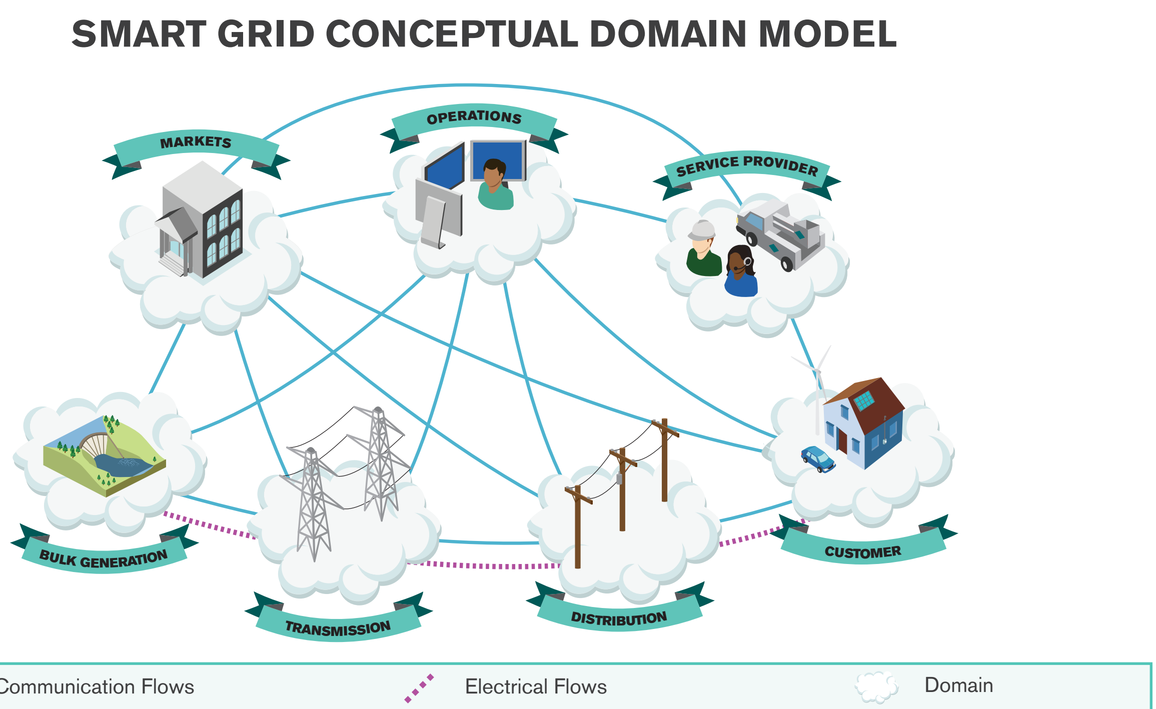
Initiated in 2009 by the National Institute of Standards and Technology (NIST), the Smart Grid Interoperability Panel (SGIP) provides a framework for this discussion by coordinating stakeholder participation and representation that is furthering the development and evolution of smart grid interoperability standards. The SGIP consists of organizations spread among 22 categories of smart grid stakeholders, including PSE, and has three primary functions:

- To oversee activities intended to expedite the development of interoperability and cybersecurity 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 also a useful tool for identifying potential intra- and inter-domain interaction and potential applications and capabilities enabled by these interactions.[2]

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

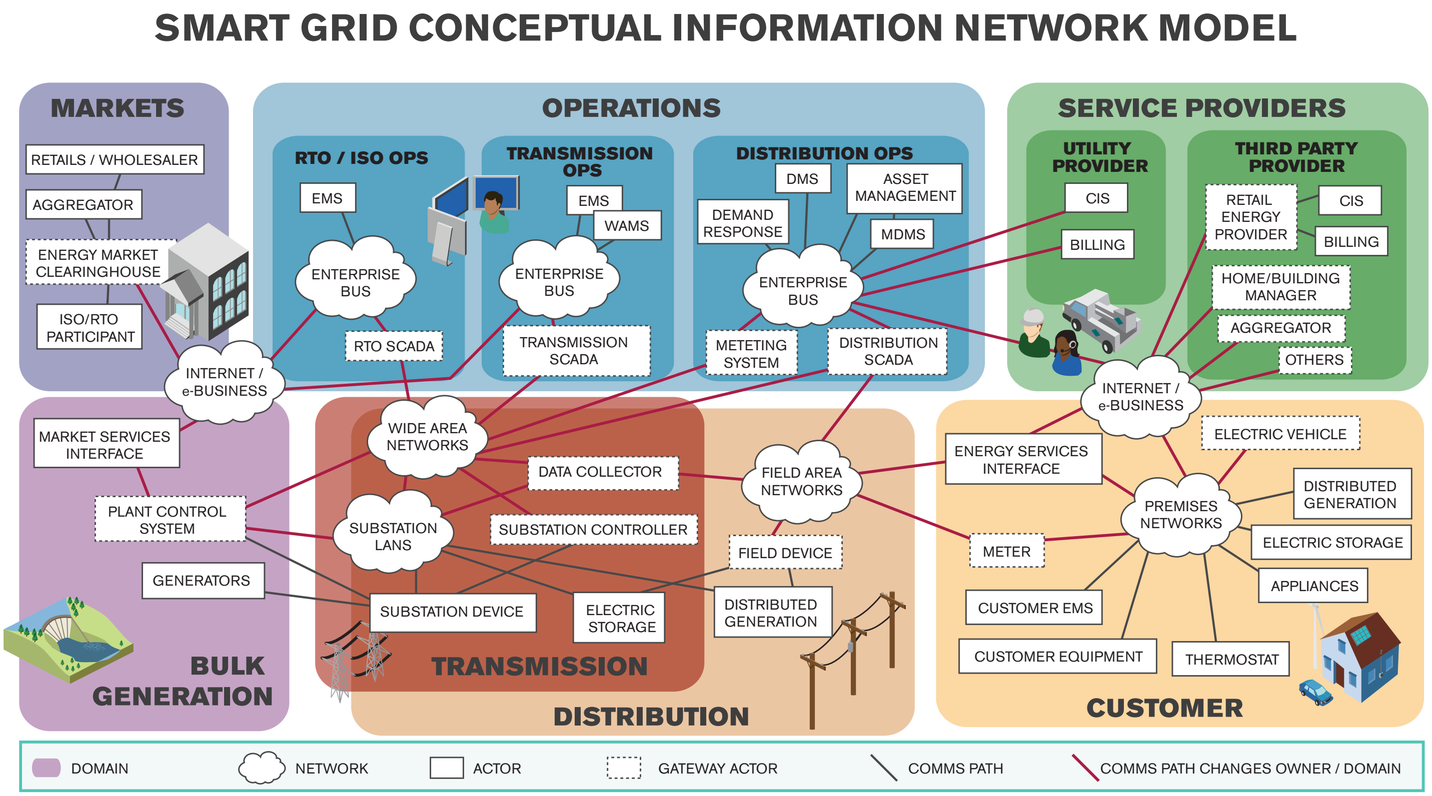


Source: NIST Smart Grid Framework 1.0 January 2012

[1,2] 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. Currently, various functions are 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 utilizing specialized protocols. However, 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 strategy and approach. With the need to integrate existing IT back-end applications and networks along with T&D components (some of which are currently working independently from each other), new technologies need to be evaluated for their integration capabilities. On top of these challenges, careful consideration needs to be given to the features that create value for customers and changes likely to affect customers, workforce and utility operations. Managing this change effectively across the company, determining where value exists for customers, and educating customers along the way will be important success factors.

Smart grid technology advancements and investments will be 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, as well as 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 will occur through careful planning and consideration of remaining useful life and the integration of existing assets, and evaluation of forward compatibility of individual systems as grid assets and the associated monitoring, communications and control systems evolve. The resulting costs of these necessary infrastructure and IT investments can be significant and may, in some cases, only demonstrate 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 be different for each company. With a significant number of variable factors, such as regional differences, environment, customer interest, and company size and infrastructure, to name a few, each company will need to define the path that is most strategic for its set of circumstances.

As smart grid advancements become a reality – particularly for PSE and our customers – a combination of environmental, resource and technology factors should be considered:

- **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), as the market and consumers will be an important driver of smart grid advancements for utilities.
- **Reliable service:** Residential and business customers depend daily on PSE 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:** The Pacific Northwest has long enjoyed some of the lowest electric power rates in the nation, due to the availability of hydropower. Although rates are beginning to experience modest increases, power costs to utility customers are still far lower in the Pacific Northwest than in other regions. This tempers some of the immediate cost benefits of certain smart grid programs like time-of-use pricing, but doesn't change the broader trend toward greater monitoring, communications and control in the energy system, which, when implemented, lead to additional operations and maintenance savings.
- **Demand-side resource options:** Additional resources are needed to meet capacity needs, largely due to expiring contracts and retiring energy generation assets. PSE's 2011 Integrated Resource Plan (IRP) outlines a need for the utility to add 1,478 megawatts (MW) of generation capacity and demand-side resources by 2016, and 2,595 MW by 2020. Options to deliver some of these demand-side resources include demand response and home automation programs. 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.
- **Heightened reliance on data-driven decisions:** Within the next 10 years, 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 40 percent of employees being eligible to retire in the next five to 10 years.

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 varying 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.

- **Renewable energy integration:** Renewable energy is of significant interest to PSE and our Pacific Northwest customers. PSE is already producing electricity from the wind and sun, and from landfill and dairy waste products, which we anticipate will 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.

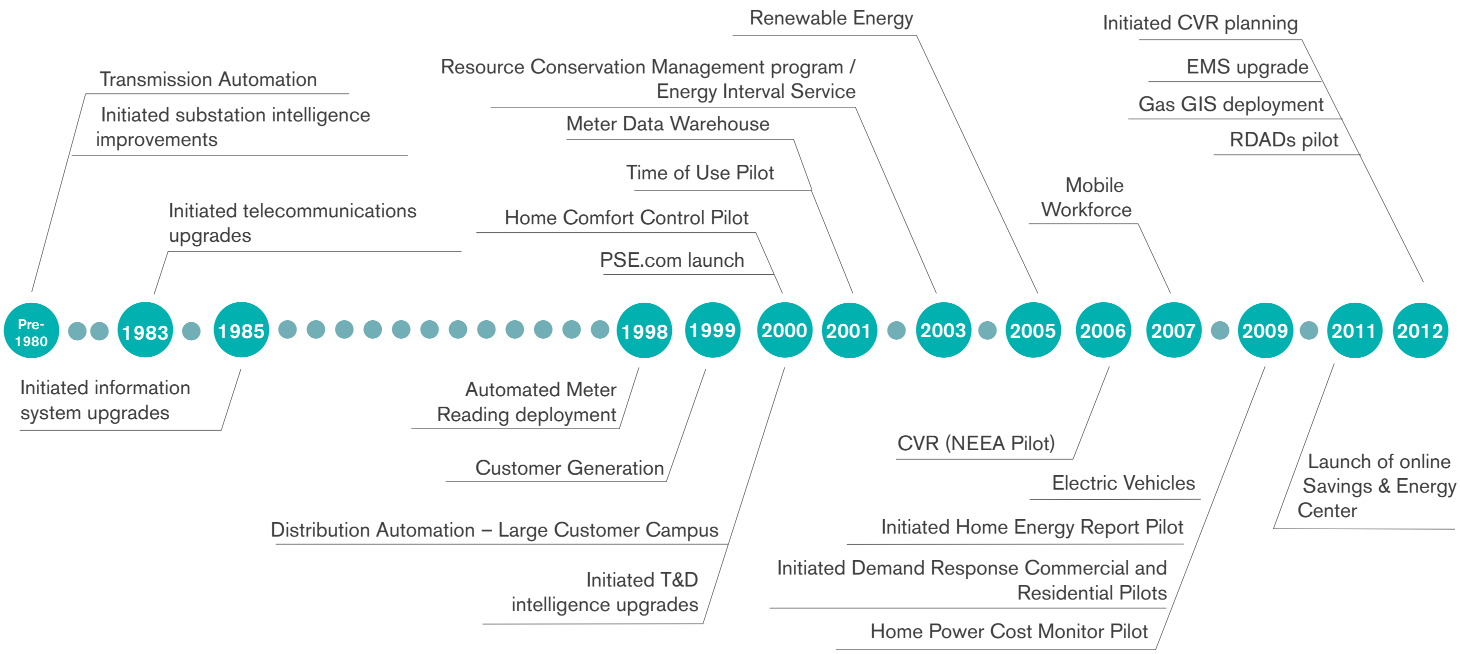
PSE's Lower Baker Dam in Skagit County

- **Infrastructure and operational opportunities:** Like many energy companies, PSE is faced with investing in aging infrastructure, which will need to be modernized or replaced to bring reliability benefits for our customers. This presents an opportunity, as modernization and/or replacement of these systems will allow the planning for both current and future needs. At the same time, with more frequent information (i.e., nearly real-time) at additional points throughout the system, enabled by a smart grid, we can improve optimization of our current electric infrastructure by making investments closer to the time when they are needed. Further, the new sources of information can allow us to optimize operations in some areas, improving performance or reducing costs.
- **Technology risk awareness:** The technology required to upgrade IT systems and enable further smart grid applications is at uneven levels of maturity for deployment. While some technologies and applications are proven and at a point where research and development (R&D) cycles have ended and commercialization has begun, others are in early formation stages and require further development. Further, 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 the needs of 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 since prior to 1980 – 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.)

Looking more specifically at the last two years, PSE embarked on a number of projects focused on improving and building foundational infrastructure, reliability and efficiency as outlined in the implementation plan of our 2010 Smart Grid Technology Report. 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 2011-2012 Proposed Smart Grid Implementation Plan

(As proposed in PSE's plan submitted to the UTC dated September 1, 2010.)

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

AREA / PROPOSED PROJECT	STATUS
INFORMATION TECHNOLOGY	
Smart Grid Enablers	
Proposed: Complete EMS upgrade to increase system security and reliability.	✓
Proposed: Implement OMS: complete evaluation by 2011; select vendor, implement with completion expected in 2012.	✓
Automated Metering	
Proposed: Complete evaluation of migrating to two-way AMI technology from one-way AMR meters in 2011.	✓
Proposed: Pilot and initiate a phased conversion from AMR to AMI, based on evaluation and business drivers.	✓
Substation IP Enablement	
Proposed: Complete evaluation of pilot to migrate T&D substations to secure IP network.	✓✓
Proposed: Continue extension of fiber optics cabling throughout T&D network.	✓✓

AREA / PROPOSED PROJECT	STATUS
CUSTOMER INFORMATION AND ENERGY EMPOWERMENT	
Customer Energy Use Information and Feedback	
Proposed: Continue to review and evaluate proposals; consider the deployment of pilot programs to learn the potential savings and value proposition to customers.	✓✓
Proposed: Continue implementation of home online tools with PSE customer base.	✓✓
Home Power Cost Monitor Pilot	
Proposed: Complete pilot and evaluate results, such as energy savings, technical feasibility and cost-effectiveness.	✓✓
Proposed: Based on pilot, determine potential broader deployment.	✓✓
Demand Response (DR) Pilots	
Proposed: Evaluate current residential and commercial DR pilots, including system performance and customer acceptance for demand response.	✓✓
Home Intelligence/Automation	
Proposed: Consider soliciting proposals for a pilot project.	+
Prepay Billing System Pilot	
Proposed: Consider soliciting proposals for a pilot project.	+
Customer Energy Generation	
Proposed: Continue to support customer adoption of small renewable generation.	✓✓
Proposed: Evaluate and implement streamlined solutions:	
»» Implement new customer interconnection process improvements for <100 kW projects.	✓✓
»» Expand renewable generation section of PSE.com website.	✓✓
»» Implement policy and process for interconnection for customer generation projects between 100 kW and 20 MW.	✓✓
Electric Vehicles	
Proposed: Update review of energy and capacity demands in latest IRP.	✓✓
Proposed: Study impacts of early electric vehicle adopters on distribution levels and develop plan for changes to planning and customer service models to support mass adoption.	✓✓
Proposed: Continue collaboration with major customers and public infrastructure in the region to support regional planning of transportation and utility infrastructure, and consumer information on location and use of charging stations.	✓✓
Proposed: Evaluate the value to customers and the utility from timed or staggered charging based on actual data from early customers. Pilot if positive economic case and communications standards and equipment are in place.	✓✓
TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE	
Transmission Automation and Reliability	
Proposed: Evaluate existing automatic transmission schemes for performance and determine the need for new schemes and/or modifications to existing schemes. Select projects based on specific benefits and costs and available funding.	✓✓
Proposed: Continue to upgrade aging/older SCADA systems in transmission substations.	✓✓
Distribution Automation	
Proposed: Continue to monitor and learn from the DA systems serving a large customer.	✓✓
Proposed: Evaluate and develop pilots in one to two select areas where reliability is an issue.	✓✓

AREA / PROPOSED PROJECT	STATUS
TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE	
Distribution Supervisory Control and Data Acquisition (SCADA)	
Proposed: Continue SCADA installation; select projects based on specific benefit and cost, and available funding.	✓✓
Proposed: Install supervisory control of feeder breakers and ampere readings on all three phases of breakers at critical distribution substations.	✓✓
Recloser Installation	
Proposed: Continue to install reclosers on overhead distribution circuits where customers would benefit from the installation.	✓✓
Proposed: Evaluate and pilot one recloser with communications for remote monitoring and control.	✓✓
Conservation Voltage Reduction (CVR)	
Proposed: Evaluate and develop plan for CVR program, and implement as budget funding allows.	✓✓

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

In addition to the progress shown above against our proposed 2010-2012 smart grid activities, PSE accomplished forward momentum on some additional smart grid enabler projects that were outside of the plan at the writing of the previous report, including:

- Development of the Operations Network – A number of the smart grid enabler projects discussed above were leveraged to either build elements of the operations network, or strengthen and improve existing elements, while increasing security and reliability of operations data transport. This "network of networks" works to provide highly reliable and secure transport of data signals related to the operation, management, control and monitoring of energy – the foundational enabling data signal transport for smart grid capabilities. PSE will continue building out the operations network over time, as multiple other projects build new, or upgrade existing, network capabilities.
- Implementation of a Gas Geospatial Information System – PSE has targeted that by September 2012, legacy map and service card data will reside in PSE's new GIS system – providing a significant increase in functionality over PSE's previous static mapping system.
- Customer Information System – Project formation and design were completed in early 2012. PSE is currently in the implementation phase.

More information about these projects and future plans is detailed in Appendix C.

With our experience (e.g., PSE's early commitments 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 to closely monitor and participate in NIST security and interoperability standards development. 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 widespread implementation.

PSE's smart grid initiatives continue to fall into three broad categories: 1) information technology, 2) customer information and energy empowerment, and 3) transmission and distribution 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 implementing DMS, upgrading our EMS and MDMS systems, completing our CIS replacement, and integrating our new OMS with other new and existing systems. PSE also plans to deploy an enterprise GIS. With these new systems come new and different requirements for configuration, maintenance and troubleshooting. PSE employees will also undergo training.

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 underway, 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 entail initiatives on customer feedback.

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

PSE's Implementation Plan (2013-2014) and 10-year Roadmap (2013-2023)

PSE's smart grid technology implementation plan continues to take into account the regional landscape and our integration approach. Our plan details our efforts for the next two years, and maps to where we see ourselves heading over the next 10 years. Our plan focuses on the implementation of smart grid technologies, and it also describes how we will support our customers as they pave their own path 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 to smart 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 and reporting tools/information, and general applications of technologies;
- Support customer energy needs/desires, e.g., electric vehicles, customer generation;
- Evaluate and strategically deploy two-way automated metering technology, expanding 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 demand response pilots/programs and other customer energy 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 vehicle services;
- 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; and
- Customers supplementing the grid with generation and/or storage during peak.

Following is 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 5). 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 UTC smart grid functions (Figure 6).

Figure 5: PSE's Proposed Smart Grid Activities Align with Relevant NIST-Standard Domains

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

Figure 6: PSE's Proposed Smart Grid Activities Align with UTC Smart Grid Functions

Smart Grid Function as Defined by WAC 480-100-505	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*
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**.	✓		✓		✓	✓	✓	✓	✓			✓		✓		✓

Smart Grid Function as Defined by WAC 480-100-505	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*
	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.	✓	✓			✓	✓	✓	✓	✓			✓				

** Conservation as defined in the law and rules.*

PSE's two-year implementation plan and 10-year roadmap broken out by smart grid component or project follow each overview, with more detail provided in Appendix C.

Information Technology

PSE is embarking on a number of projects outlined below, which are being leveraged to either build or 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 restoration, enhanced customer service/communication and improved billing and payment options, just to name a few. Essentially, PSE is working to create the foundational enabling data signal transport for all smart grid capabilities.

With several core capability projects already underway, including building and strengthening PSE's core operations network, and the upgrade or implementation 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

2013-2014 Plan

- EMS
  - Complete second release of EMS upgrade
- MDMS
  - Upgrade MDMS system
  - Consider integration of near real-time Web interface
  - Implement CIM standard interface for information
- Electric GIS/OMS
  - Complete electric GIS/OMS installations
- CIS
  - Complete CIS replacement: evaluate test phase, prepare go-live and finalize system stabilization
- Gas GIS
  - Consider additional applications to leverage GIS
- DMS
  - Implement DMS: receive product release, schedule implementation project
  - Integrate with CIS, OMS and upgraded MDMS systems
- Substation IP Enablement
  - Continue implementation of SCADA using IP technology
  - Complete the evaluation of IP SCADA for generation sites

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 select substations to IP requiring back-up control center communications
- Continue extension of fiber optics cabling throughout T&D network

Automated Metering

2013-2014 Plan

- Evaluate AMI technology and business value, consider targeted deployments, and develop a roadmap for AMI implementation

10-year Roadmap

- Continue AMR-AMI conversion, as appropriate

Energy Trading and Risk Management

2013-2014 Plan

- Begin implementation of integrated ETRM solution to replace existing natural gas and power management systems

10-year Roadmap

- Complete implementation of integrated ETRM solution

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 their 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 capabilities and reporting tools/information; better information through two-way automated metering technology; and other customer energy capabilities such as household energy usage and 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

2013-2014 Plan

- My PSE Account
  - Complete redesign and migration of My PSE Account (customer account platform) into newly upgraded PSE.com environment enabling new or improved customer self-service features and future mobile capabilities
- PSE.com/Online Tools
  - Continue implementation of online tools and capabilities that enable customers to take better control of their energy use
- Home Energy Report
  - Continue to offer reports to customers to test the durability and longevity of energy savings

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

2013-2014 Plan

- Anticipate and support continued rapid program growth (4,500 net-metered customers are projected by the end of 2017)
- Implement automated monthly billing and improved payment and location tracking with the implementation of CIS
- Consider 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

2013-2014 Plan

- Continue to monitor and study real-world charging data to further understand PEV load impacts; consider distribution upgrades, as appropriate
- Add to PSE's fleet of demonstration vehicles with a focus on high-usage trucks and vans
- Perform a comprehensive analysis of the feasibility and cost benefit of various tactics to reduce peak load impacts from PEVs
- Provide continued support to customers and adoption of PEVs

10-year Roadmap

- Develop energy and demand forecasts based on already experienced adoption rates and needs
- Incorporate EV 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

PSE will continue to explore, evaluate and selectively deploy T&D smart grid strategies over the next 10 years and beyond. Driven by our objective to provide safe and reliable service, such strategies will be evaluated and many will be piloted prior to implementation. These evaluations and pilots will consider the diversity of our service area (i.e., downtown core, suburban, rural), and the high density of trees and vegetation, as all can be a challenge to reliability. In addition, maintaining decades-old infrastructure, including the existing smart components on our T&D system, requires a level of replacement that is expected to continue and possibly increase as the smart grid continues to evolve.

PSE cross-country transmission lines

Coordination between T&D and IT will help ensure appropriate cost/benefit at each step/stage as the upgrade and consolidation of the operations network and end-use applications are planned.

Transmission Automation and Reliability

2013-2014 Plan

- Continue 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
- Depending on benefit/cost, selectively replace aging components with modernized equipment that will facilitate smart grid adaptability

Distribution Automation Projects

2013-2014 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 50-80 overhead circuits
  - Evaluate the benefits of reclosers with communications and monitoring capabilities
- 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 select distribution substations
- Remote Data Acquisition Devices (RDADs) Pilot
  - Continue installation of RDADs in the Bellevue Central Business District (CBD) to further explore different types of installation available with existing PSE equipment
  - Develop an integration plan to incorporate RDAD equipment into PSE's new DMS system
- Distribution Automation - Bellevue CBD
  - Continue to replace manual switches with SCADA switches in the Bellevue CBD to enhance management of outage restoration, and to facilitate automatic switching in the future
- Conservation Voltage Reduction (CVR)
  - Implement CVR on six to nine substations to improve efficiency of selected distribution circuits and reduce electric power consumption

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 capability 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 electric power consumption

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

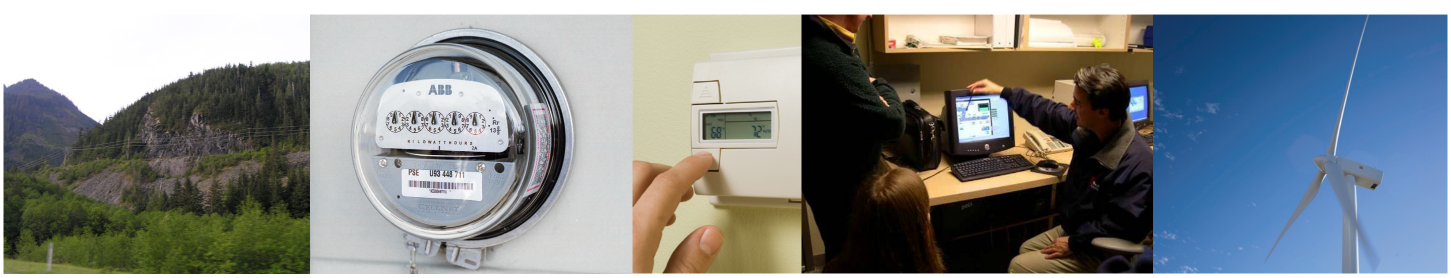
Smart grid technologies have the potential to strengthen the nation's energy infrastructure, and empower decision-making for utilities and their customers by providing timely information on energy usage, the operation of the grid, and energy production.

One key to smart grid deployment will be prudent and systematic introductions of smart grid technology at each level of infrastructure, from T&D and IT systems, to customer premises applications and information systems. System interoperability and standards definition both play critical roles in this deployment.

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 comprehensive evaluation of smart grid technologies to ensure that the technologies deliver anticipated benefits and results; that they are interoperable; that vendors will continue to support and develop/improve the technologies over time; that the technologies are cost-effective; and that PSE customers will accept and adopt the technologies.

A third critical focal area will be cost recovery 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.



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.

ARRA – American Recovery and Reinvestment Act.

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.

CAD – Computer-aided Design.

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.

Cloud Computing – Internet-based computing, whereby shared resources, software, and information are provided to computers and other devices on demand.

CMS – Customer Management System.

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

Conservation Resources Advisory Group (CRAG) – A group of stakeholders providing guidance for PSE's energy efficiency program planning and delivery including: WUTC staff, Attorney General Office of Public Counsel, NW Energy Coalition, Energy Project, Natural Resources Defense Council, Northwest Power and Conservation Council, Industrial Customers of Northwest Utilities, Northwest Industrial Gas Users, Washington State Department of Commerce, and the DOE Weatherization Assistance Program provider network. Additionally, customer representatives from the residential, commercial, industrial, and institutional sectors serve on the Advisory Committee. Other interested parties may attend Advisory Committee meetings as well, but will not be considered Advisory Committee members.

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 homes, thereby reducing electric power consumption.

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.

CRAG – Conservation Resources Advisory Group.

Customer Energy Generation – Where utility customers produce their own energy (e.g. solar panels, wind turbines).

Customer Management System (CMS) – An independent database and user interface that tracks customer contacts regarding energy efficiency outreach and implementation, similar in function to a customer relationship management tool. A CMS is able to extract, mine, prioritize, sort and append customer data with other data elements for the purposes of generating leads and tracking participation for energy efficiency programs.

CVR – Conservation Voltage Reduction.

DA – Distribution Automation.

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 sphere of function. 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.

EES – Energy Efficiency Services.

EIS – Energy Interval Service.

EISA – Energy Independence and Security Act.

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.

Failover – Backup operation that automatically switches to a standby network if the primary system fails or is temporarily shut down for servicing. Failover is an important fault tolerance of mission-critical systems that rely on constant accessibility.

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.

IED – Intelligent Electronic Device.

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.

Interoperability – The ability of software and hardware on multiple machines from multiple vendors to communicate.

IP – Internet Protocol.

IRP – Integrated Resource Plan.

IT – Information Technology.

kV – Kilovolt.

LC – Load Control.

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 power stations to store excess electrical power during low-demand periods for release as demand rises.

Load Office – PSE Power System Control Center. Its functions are to sense the pulse of the power system, adjust its condition, coordinate its movement, and provide defense against internal/external events occurring to the power system.

MDMS – Meter Data Management System.

MDW – Meter Data Warehouse.

MEMS – Meter Exception Management System that helps track billing issues.

MW – Megawatt.

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.

PAP – Password Authentication Protocol.

PCT – Programmable Communicating Thermostat.

PEV – Plug-in Electric Vehicle.

Phasor – A number that represents both the magnitude and phase of an electric signal.

PLC – Programmable Logic Controller.

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.

PMU – Phasor Measurement Unit.

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.

Programmable Logic Controller – A digital computer used for automation of electromechanical processes.

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.

R&D – Research and Development.

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.

RFI – Request for Information.

RFP – Request for Proposal.

RTU – Remote Terminal Unit.

SCADA – Supervisory Control and Data Acquisition.

Self-Healing – Technology capable of automatically repairing itself.

SGIP – Smart Grid Interoperability Panel.

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.

TCP/IP – Transmission Control Protocol/Internet Protocol.

TDM – Time-Division Multiplexing.

Time-Division Multiplexing (TDM) – A type of digital multiplexing in which two or more signals are transferred apparently simultaneously as sub-channels in one communication channel, but are physically taking turns on the channel. The time domain is divided into several recurrent time slots of fixed length, one for each sub-channel.

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

V – Volt.

VAR – Voltage Ampere Reactive.

Virtualization – A technique used to provide a simulated environment where a variety of different operating systems can be run on a single machine.

Voice over Internet Protocol (VoIP) – The delivery of voice-based communications over the Internet.

VoIP - Voice over Internet Protocol.

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.

VPN – Virtual Private Network.

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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 7 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 300 miles of fiber optics lines and 40 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 Network Management System – Installed in 1997 to provided 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

Communications is managed today primarily through two types of systems, one IP and the other TDM (time-division multiplex). 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 1985-2000, PSE acquired or developed most of the back-end legacy information systems (e.g., CIS, EMS, components of an OMS and DMS) that support PSE's business. And from 2000-2009, PSE developed seven discrete and secure networks to serve as the communications backbone for PSE's gas, electric and information assets, and continued to enhance and customize the back-end information systems to reflect PSE's evolving business needs. Recognizing that many of information systems would not continue to be sustainable with new and emerging business needs, PSE initiated RFI/RFP processes and overall system and network architectural studies in 2008 and 2009 to determine future direction and system replacement/upgrade strategies, as well as develop a path for consolidating the networks into one or two company networks under a virtual private network (VPN) structure. Also in 2009, PSE 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 back in 1995. There were three pilots using different technologies between 1995 and 1998, when a decision was made and deployment began. The system uses a one-way radio frequency transmission from the meter. Deployment ran from 1998 – 2002, at which time all but 70,000 meters were changed. The final phase to capture those 70,000 was completed during the summer months of 2006. Total automation today includes just over 1.9 million natural gas and electric meters.

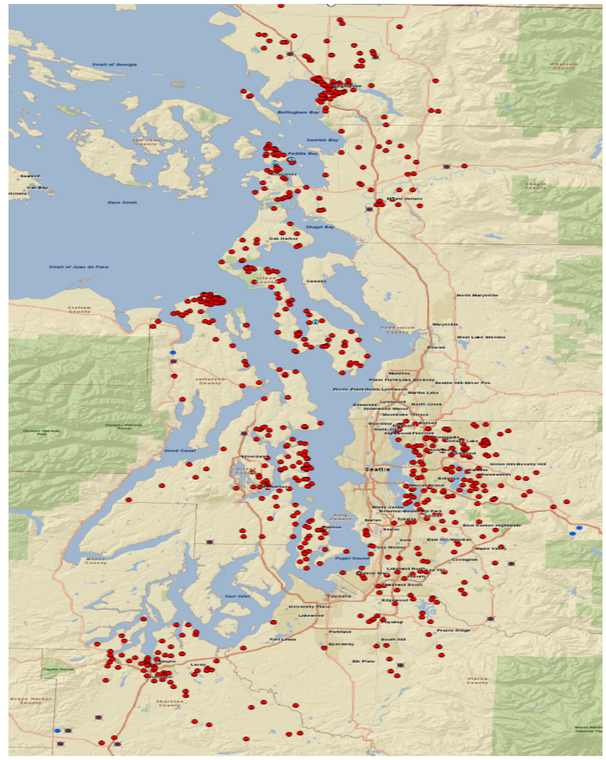
PSE meter

1999

Customer Generation

PSE's support of customer generation programs began in 1999 with the Net Metering program. Presently, 1,214 customer generation systems contribute to the grid, with 96 percent of customers generating energy from solar photovoltaic (PV) systems. The program grew slowly until July 2005. In 2005, Washington state implemented the Renewable Energy Cost Recovery Program, which is an incentive-based program where customers with eligible 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. PSE currently uses a legacy billing system, so production of "net bills" that net energy generation against energy consumption per household or business are manually calculated. PSE is working to automate this process in the new CIS billing system.



Customer generation across the PSE service area

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 on 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.

Recloser on PSE power pole

Transmission & Distribution Intelligence Upgrades

In 2000, PSE began installation of 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 degrees F or 4 degrees 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

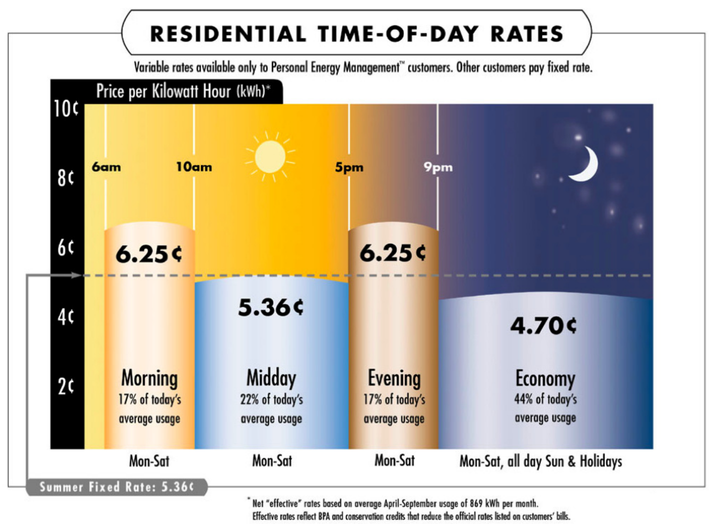
PSE's website, PSE.com, launched in 2000. In 2005, My PSE Account was added, which allowed customers to view their statements, leverage home energy tools to download energy use analyzers, see their previous days' energy consumption, and pay their energy bills online, all of which was made possible by 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 Pilot (TOU)

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 half of 1 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 manage customer expectations about 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.; and do your laundry on Sunday.

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. Initially the MDW served as a storage facility for data. Between 2002 and 2008, the system was enhanced to include functions like validation, load profile, service order, diagnostic flags, outage and customer presentment. Tools were 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. This includes accepting multiple meter read files daily, enhanced outage reporting for both end points and network equipment, read recovery capability and Web services for real-time applications.

2003

RCM Program/Energy Interval Service

Prior to the 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.

Data in a digital format enables the analysis of energy use which in turn identifies opportunities to adjust building system performance for optimization

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 and so far the only 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.

Demonstration solar array at PSE's Wild Horse Wind and Solar Facility

2006

Conservation Voltage Reduction (CVR) – NEEA Pilot

PSE originally conducted its first CVR study on 10 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. Commonly referred to as CVR, 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 1 to 3 percent total energy reduction, 2 to 4 percent reduction in kW demand, and 4 to 10 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.

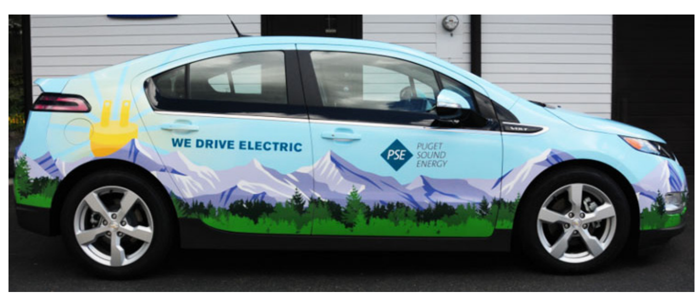
Mobile Workforce

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

Electric Vehicles

Recognizing that PSE's customers would be acquiring electric and plug-in 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 our 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.



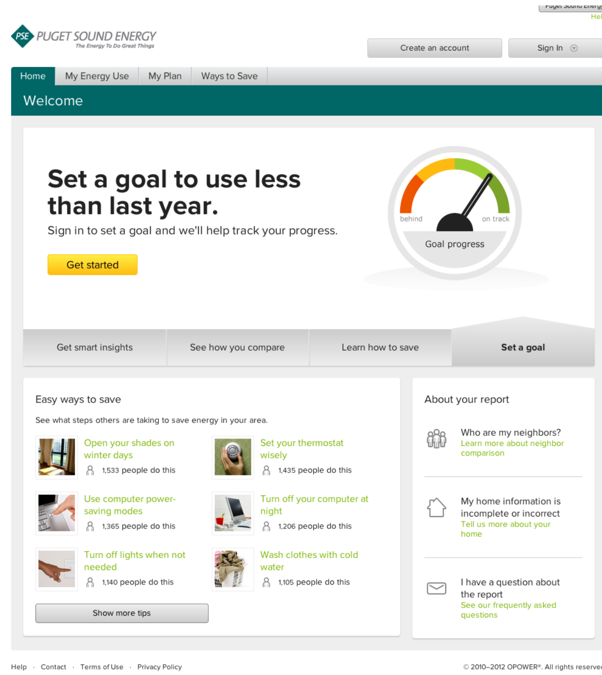
PSE's Chevy Volt

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.

Each Home Energy Report contains 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 the prior year's;
- 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.



Home Energy Reporting

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 (C/I) 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:

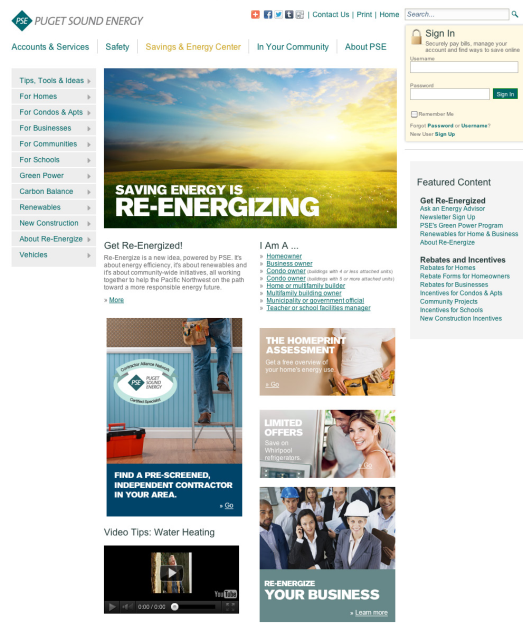
In 2009, PSE piloted the use of the Blueline (a third-party provider) Innovations Power Cost Monitor with 1,000 customers. The device works by having an optical sensor attached to the customer's meter to read the meter and wirelessly send a signal to an in-home display. The customer enters the utility 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:

- 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



Savings and Energy Center on PSE.com

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 proposed substations were selected mainly for their residential loading. 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 deployed an upgraded 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.

Gas Geospatial Information System (GIS)

PSE has targeted that by September 2012, legacy map and service card data will reside in PSE's new GIS system – providing a significant increase in functionality over PSE's previous static mapping system. The upgraded system is based on the Gas Distribution Office product, part of 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 network. For example, the system provides easier access to network asset location and characteristics, and enables PSE's gas distribution network to be managed and maintained more safely and effectively. It enables increased network reliability and greater levels of service to PSE's natural gas customers.

Remote Data Acquisition Devices (RDADs) Pilot

In 2012, 60 RDADs were installed in 20 switch locations in Bellevue's Central Business District to determine compatibility with existing switch gear and communication via cell phone text signal. RDADs report back to the system operator daily with the snapshot hourly load data and daily peak load to aid in normal switching operations. This will aid PSE System Operators with normal operational switching and allow quicker response to faulted equipment by reducing the need for trouble shooting. Of the 60 units, 59 are functioning as expected and PSE is obtaining data. Further work is being done to determine the issues with the final unit.

Appendix B

Progress Report on PSE's 2011-2012 Proposed Implementation Plan

(As proposed in PSE's plan submitted to the UTC dated September 1, 2010.)

The following chart details PSE's efforts in 2011 and 2012 and provides an overall progress report on the proposed two-year plan in our 2010 Smart Grid Technology Report.

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

AREA/PROPOSED PROJECT DETAILS	STATUS
INFORMATION TECHNOLOGY	
Smart Grid Enablers	
Proposed: Complete EMS upgrade to increase system security and reliability. ***Status Details:*** PSE completed the EMS upgrade (Release 1) in Q2, 2012 (originally expected to be completed by end of 2011).	✓
Proposed: Implement OMS: complete evaluation by 2011; select vendor, implement with completion expected in 2012. ***Status Details:*** PSE has delayed completion of the OMS upgrade to 2013 to allow for more fully developed foundational data competencies and ensure system readiness by the 2013-14 storm season. Additionally, PSE opted to separate the implementation of DMS from OMS while General Electric made some significant revisions to the product. Completing OMS and DMS integration continues to be on track for completion by 2020.	✓
Automated Metering	
Proposed: Complete evaluation of migrating to two-way AMI technology from one-way AMR meters in 2011. ***Status Details:*** PSE's extensive analysis and evaluation of two-way technology identified the top scenarios for transitioning to an AMI system, as well as a need for continued evaluation. Further analysis will occur through 2013 to strengthen the business case for migrating to AMI and to more thoroughly identify the preferred system architecture and functional requirements of an AMI system.	✓✓
Proposed: Pilot and initiate a phased conversion from AMR to AMI, based on evaluation and business drivers. ***Status Details:*** PSE has initiated a demonstration of the AMI technology in a laboratory setting and anticipates expanding the demonstration to about 20 meters in production by 2013. The demonstration is expected to inform planning for a migration to AMI.	✓
Substation IP Enablement	
Proposed: Complete evaluation of pilot to migrate T&D substations to secure IP network. ***Status Details:*** PSE installed 68 miles of fiber optics cabling in 2011 and 2012. PSE continues to use the synergy of different projects to maximize the amount of cable that is installed throughout the network.	✓✓
Proposed: Continue extension of fiber optics cabling throughout T&D network. ***Status Details:*** Completed evaluation of IP SCADA implementation at Juanita and North Bellevue substations in 2010. As a result of the pilot, hardware and facilities standards were identified, including routers, SCADA remote termination units (RTU), analog-to-IP converters, emergency power systems and new communications structures.	✓✓

AREA/PROPOSED PROJECT DETAILS	**STATUS**
CUSTOMER INFORMATION AND ENERGY EMPOWERMENT	
Customer Energy Use Information and Feedback	
Proposed: Continue to review and evaluate proposals; consider the deployment of pilot programs to learn the potential savings and value proposition to customers. ***Status Details:*** PSE completed a three-year Home Energy Report Pilot in 2011. The goal of the pilot was to gain knowledge of customer acceptance, energy savings potential, and the cost-effectiveness of the pilot program and the persistence of savings. Results were favorable for the cost-effective behavior modification/energy savings program. Results show that households that received reports for the three-year duration are continuing to conserve energy. Households that were suspended from the program after two years are continuing to use less energy than control households, but they use more energy than households that received reports for the full three years of the program.	✓✓
Proposed: Continue implementation of online tools for PSE customer base. ***Status Details:*** Along with a redesigned website, PSE launched an online energy efficiency dedicated Savings & Energy Center in April 2011. The updated PSE.com boasts an improved user experience, with more intuitive navigation and new online tools to help customers understand and reduce their energy usage. The site 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. Additional features include: • 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 Since launching, the Savings & Energy Center has seen a significant uptick in page traffic and overall engagement with customers: • The "Savings & Energy Center" received more than 920,000 page views with an average time of about 1 minute 25 seconds spent on each page, an increase of more than 30 percent in page views over the old website, during the same period the year prior. • There were more than 124,000 views of the residential Rebates & Offers page, an increase of 55 percent over the same period the year prior on the old website. The commercial Rebates & Incentives page received more than 13,000 page views. • There were more than 20,900 views of the Ask an Energy Advisor inquiry form page, an increase of 38 percent over the same period the year prior on the old website. • There were more than 24,500 views of the Contractor Referral Service referral page, an increase of 34 percent over same period the year prior on the old website. • There were more than 8,600 views of the efficient product retailer and dealer locator maps; more than 5,000 views of the Interactive Rebate Finder and more than 3,000 views of the Re-Energize splash page. In addition, PSE completed the Home Energy Report pilot in 2011. These reports provide customers with a comparison of their household energy usage to energy usage from nearest like neighbors (anonymized). 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 action items tailored to help each customer save money and improve energy efficiency. *Continued on next page...*	✓✓

AREA/PROPOSED PROJECT DETAILS	**STATUS**
CUSTOMER ENERGY USE INFORMATION AND FEEDBACK	
Customer Energy Use Information and Feedback	
Continued from previous page... After three years of receiving reports, households continued 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 continued to use less energy than control households, but they used more energy than households that remained in the program for three years. With these favorable results, PSE continued delivering reports to 24,000 households throughout 2012 and plans to continue the program through 2013 to test the durability and longevity of energy savings.	
Home Power Cost Monitor Pilot	
Proposed: Complete pilot and evaluate results, such as energy savings, technical feasibility and cost-effectiveness. ***Status Details:*** PSE completed the Blue Line (a third-party provider) Home Power Cost Monitor Pilot in 2010. Lessons learned include: • Installation and synchronization of the monitor was challenging for customers. • A utility rate change would require the customer to calculate the new nominal average cost per kWh and to program the cost in the monitor. • The required maintenance of periodically replacing batteries in the monitor and the outdoor sensor was inconvenient. • Many customers lost interest in using the monitor over time. This occurred after they understood the normal cycling patterns of their major electrical uses and had gained an understanding of the cost of operating electric loads like their water heater, dryer or heat pump (compared to cooking range burner or microwave oven, for example). Any utility should examine this familiarity/loss of interest cycle in considering a full-scale monitor program. • Use of a monitor for a few months may well suffice to impart a long-term understanding among members of a household of the cost and energy use associated with major appliances. • Newer, more customer-friendly technology coming into the marketplace will likely replace this early product. Upon completion of the pilot, PSE determined that challenges and limitations of the pioneering technology of the monitor did not make it viable for continued, large-scale customer use. PSE planned to hire a qualified statistician to provide an impact evaluation of the pilot data; however, information gathered from other larger-scale regional and national pilots of the product concluded that the technology did not yield consistently significant energy savings.	✓✓
Proposed: Based on pilot, determine potential broader deployment. ***Status Details:*** Based on pilot results, PSE determined broader deployment is not viable with this technology.	✓✓
Demand Response (DR) Pilots	
Proposed: Evaluate current residential and commercial DR pilots, including system performance and customer acceptance for demand response. ***Status Details:*** Third-party evaluations were completed and the results are summarized below. ***Commercial/Industrial (C/I) Load Control Pilot*** This pilot with 25 participating commercial-industrial customers was designed to provide direct utility experience working with a service provider to curtail winter and summer loads during system peak demand periods during cold and hot weather. Evaluation of the pilot was completed in September 2011. The average event realization rate was 83 percent during winter and 140 percent during summer. Satisfaction of customers with their participation experience was high. Most indicated an interest in enrolling in a future demand response program offered by PSE. Experience gained in conducting the pilot has greatly facilitated the utility's recent planning and RFP process for a long-term commercial-industrial demand response program. Lessons learned include: • Customer recruitment was challenging in terms of gaining sufficient focused attention to fully understand the offer and signing a participation agreement. Automated curtailment was initially offered, though later downplayed in initial presentations due to facility manager concerns over not "having control" of their operations during curtailment events. *Continued on next page...*	✓✓

AREA/PROPOSED PROJECT DETAILS	**STATUS**
CUSTOMER INFORMATION AND ENERGY EMPOWERMENT	
Demand Response (DR) Pilots	
Continued from previous page... • Recruitment was greatly expedited when local branch facilities of national chains received corporate encouragement, based on experience with other US utility curtailment programs. • The provider must have a high degree of sensitivity and insight into how each facility operates, so that only discretionary loads are curtailed and normal parameters for comfort, production, etc., are maintained during control events. • The provider must have excellent technical skills in identifying discretionary curtailable electric loads in a variety of facilities. • Provider operations, meter data management, analysis and security and cyber security protocols require a high degree of technical expertise. The 2011 IRP suggests building a demand response program beginning with C/I customers. In October 2011, PSE issued an RFP to provide program design and implementation for demand-side capacity reductions from targeted C/I customers. PSE is currently conducting a thorough analysis and considering options for a demand response program. ***Residential Load Control*** The residential demand response pilot was a two-year project applying direct load control of electric space and water heat on Bainbridge Island targeting up to 700 customers. The project used load switches and communicating thermostats and hosted software and services provided by a national demand response services provider. Communications between the software and wireless switches and thermostats were via internet protocol over customers' existing broadband service. While the Bainbridge community was highly responsive to the pilot promotion and recruitment process, total enrollment in the pilot reached and stabilized at 530 participating homes, short of the original target. The original two-year term of the pilot was extended to include an additional winter event season because of initial software reporting problems encountered by the provider. Original budget projections including costs of hardware, hosted software and services plus customer enrollment, field installation of equipment, post installation site maintenance and equipment removal were projected to be $1.5 million. Extension of the pilot and additional incurred costs were the result of a product manufacturer's safety recall action of 210 of the installed thermostats. Lessons learned include: • Residential direct load control (particularly) in a winter heating climate is a challenging and complex undertaking, even with the most current technology available. • Explaining demand response and differentiating it from traditional energy conservation in the minds of residential customers is also challenging. • Instilling a reasonable understanding of the value of reducing peak demand during a few hours out of the entire year will take considerable time in a ramp to any potential future demand response program. • Adding demand response control capability to heat pumps in customer homes is layered with technical and participant comfort risks that must be addressed methodically in the process of field installation technician selection, training and record-keeping. • Two-way communications between the load management software and control hardware installed in each home must maintain a high degree of connectivity to ensure reliable load sheds and restorations without need to engage customers in the process of troubleshooting or scheduling technical service visits to their homes. • Even with the most exhaustive care in making vendor and technology selections, the complexity of implementing new technology applications with customers demands a carefully considered and deep commitment to problem resolution for an extended period of time. • Even strong vendors are not immune to the effects of a protracted downturn in the business cycle in terms of ability to achieve all of the outcomes envisioned when the project commitment was made. The current plan for residential DR is to monitor the marketplace and advances in DR technology. PSE will likely conduct another residential DR pilot prior to developing a residential DR program.	

AREA/PROPOSED PROJECT DETAILS	STATUS
CUSTOMER INFORMATION AND ENERGY EMPOWERMENT	
Home Intelligence/Automation	
Proposed: Consider soliciting proposals for a pilot project. ***Status Details:*** PSE considered a pilot to identify energy savings potential by utilizing communicating home intelligence/home automation devices. However, PSE found challenges in measuring savings and has not seen quantifiable benefits from the concept of a home area network. Therefore a pilot was not pursued.	+
Prepay Billing System Pilot	
Proposed: Consider soliciting proposals for a pilot project. ***Status Details:*** PSE determined the benefit to energy efficiency savings alone was not sufficient to warrant further steps in developing a pilot at this time. As PSE builds our smart grid architecture, this application may offer benefit in accompaniment with other applications enabled by the technology. PSE is continuing to learn about our customers' needs and preferences in order to provide excellent customer service. Prepay billing appears to be a preference among a specific segment of customers.	+
Customer Energy Generation	
Proposed: No specific technology changes, evaluations or projects are anticipated in the next two years, however, PSE will continue to support customer adoption of small renewable generation. ***Status Details:*** The number of customers producing electricity increased by 29 percent in 2011. All systems that can feed electricity into PSE's distribution network are known and mapped by location, technology and capacity.	✓✓
Proposed: Evaluate and implement streamlined solutions:	
»» Implement new customer interconnection process improvements for <100kW projects. ***Status Details:*** New customer interconnection process improvements for systems <100kW have been made to simplify customer applications and interconnection. Multiple forms and applications have been replaced by a single streamlined, customer-friendly document.	✓✓
»» Expand renewable generation section of PSE.com website. ***Status Details:*** The renewable generation section of PSE.com was expanded to include net metering, production metering and local energy development.	✓✓
»» Implement policy and process for interconnection for customer generation projects between 100 kW and 20 MW. ***Status Details:*** Application and interconnection process improvements continue to be ongoing.	✓
Electric Vehicles	
Proposed: Update review of energy and capacity demands in latest IRP. ***Status Details:*** PSE completed a comprehensive analysis of PEV sales forecasts, energy and peak load impacts, and financial implications.	✓✓
Proposed: Study impacts of early electric vehicle adopters on distribution levels and develop plan for changes to planning and customer service models to support mass adoption. ***Status Details:*** PSE's distribution system study is complete and we conclude that impacts are negligible over the next five years.	✓✓
Proposed: Continue collaboration with major customers and public infrastructure in the region to support regional planning of transportation and utility infrastructure, and consumer information on location and use of charging stations. ***Status Details:*** PSE is a participant on the State PEV Task Force and is working closely with entities/partners working to site and interconnect public PEV charging infrastructure.	✓✓

AREA/PROPOSED PROJECT DETAILS	STATUS
CUSTOMER INFORMATION AND ENERGY EMPOWERMENT	
Electric Vehicles	
Proposed: Evaluate the value to customers and the utility from timed or staggered charging based on actual data from early customers. Pilot if positive economic case and communications standards and equipment are in place. ***Status Details:*** Preliminary analysis suggests that time-differentiated EV pricing is not feasible or cost-effective until PSE completes the new customer information system and a substantially greater number of EVs are on our system.	✓✓
TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE	
Transmission Automation and Reliability	
Proposed: Evaluate existing automatic transmission schemes for performance and determine the need for new schemes and/or modifications to existing schemes. Select projects based on specific benefits and costs and available funding. ***Status Details:*** PSE installed supervisory control on 115 kV transmission line switches located within the Enterprise Substation in Ferndale and the Olympic Renton Substation in Renton. In both cases, the switches already had automatic controls but did not have supervisory control. Additionally, new automatic and supervisory control was installed on 115 kV transmission line switches located on the Enserch-Bellingham #1 115 kV line in Bellingham.	✓✓
Proposed: Continue to upgrade aging/older SCADA systems in transmission substations. ***Status Details:*** Upgrades to aging/older SCADA systems were implemented at the following substations: South Bremerton, Boeing Aerospace, Baker River Switch, Viking, Horse Ranch and Yelm in 2011; Alderton and Olympia in 2012. PSE continues to use the synergy of different programs to fund upgrades to aging SCADA systems in transmission substations.	✓✓
Distribution Automation (DA)	
Proposed: Continue to monitor and learn from the DA systems serving a large customer. ***Status Details:*** PSE continues to learn from the DA systems serving a large customer. Implementation of this project, specifically the programming for the self-healing automation, is a labor intensive effort – more so than originally planned. PSE also learned that the self-healing automation programming is not as flexible as desired when changes to the system are made. PSE is identifying new vendors that are developing software that is easier to adapt to changes in the system configuration.	✓✓
Proposed: Evaluate and develop pilots in one to two select areas where reliability is an issue. ***Status Details:*** In November 2011, PSE completed a final report that identified Bellevue's Central Business District (CBD) as an appropriate area for a DA pilot. The electric system in Bellevue's CBD has a very high-density load that requires many switches be placed in close proximity to each other (primarily in the sidewalks along busy streets). To perform normal or emergency switching requires servicemen to commute through high-traffic areas and access vaults in the sidewalk or street interrupting pedestrian and vehicle traffic. The purpose of this pilot is to determine what is necessary to install SCADA infrastructure in distribution switch gear. The project scope is to replace seven current manual switches for two circuits within the CBD with SCADA switches. Installation of all seven SCADA switches will be completed in 2012. PSE will then connect the controllers of these switches with fiber optic cables and build an interface with the PSE EMS system. PSE is currently in the process of evaluating different DA options. Once complete and the system is fully operational, PSE will continue to implement an automation control system that will analyze site data, isolate problems, and restore electricity to customers.	✓✓
Distribution Supervisory Control and Data Acquisition (SCADA)	
Proposed: Continue SCADA installation; select projects based on specific benefit and cost, and available funding. ***Status Details:*** PSE has been installing and upgrading the SCADA system in PSE-owned distribution substations to better monitor and control substation equipment and the distribution system. Since 2010, three substations have been added to PSE's SCADA system, providing coverage of 98 percent of PSE distribution substations. Monitoring of three-phase amps has been upgraded in 27 substations (87 percent coverage in 2012, up from 77 percent in 2010) and distribution breaker supervisory control has been upgraded in six substations (19 percent coverage in 2012, up from 17 percent in 2010).	✓✓

AREA/PROPOSED PROJECT DETAILS	**STATUS**
TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE	
Distribution Supervisory Control and Data Acquisition (SCADA)	
Proposed: Install supervisory control of feeder breakers and ampere readings on all three phases of breakers at critical distribution substations. ***Status Details:*** Over the past two years, PSE upgraded 24 substations with three-phase ampere readings on all breakers and added supervisory control of the feeder breakers on 13 substations.	✓✓
Recloser Installation	
Proposed: Continue to install reclosers on overhead distribution circuits where customers would benefit from the installation. ***Status Details:*** At the end of 2011, PSE has installed more than 500 reclosers on our overhead distribution circuits – more than 140 of which were installed during the past three years.	✓✓
Proposed: Evaluate and pilot one recloser with communications for remote monitoring and control. ***Status Details:*** PSE installed three reclosers with communication for remote monitoring and control. Evaluation is underway.	✓✓
Conservation Voltage Reduction (CVR)	
Proposed: Evaluate and develop plan for CVR program, and implement as budget funding allows. ***Status Details:*** PSE completed analysis of 12 substations and is designing the program in 2012, with implementation starting in 2013/2014. With lessons learned from initial substations, the program design and metrics will be updated and applied for the rest of the substations.	✓✓

Appendix C

Details of PSE's Two-year (2013-2014) 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, might contribute to its systems. A full catalog of these technologies would span the industry and its vendors. Certain technologies are evaluated in more depth; and those under such active consideration are discussed below.

The following plans may be adjusted as we continue to 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.

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 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 quicker outage restoration, enhanced customer service and improved billing and payment options, just to name a few. Essentially, PSE is working to create the foundation to enable smart grid capabilities.

Critical projects include building or upgrading our CIS, OMS, DMS, EMS and MDMS systems, and integrating new and existing systems. Additionally, PSE is evaluating options and business values for transitioning from our one-way AMR system to two-way AMI technology. PSE will also continue the initiative to transition telecommunications traffic to Internet Protocol (IP). With these systems in place, PSE will have the foundational technology to enable new applications like remote disconnects/reconnects for electric customers. Moreover, these systems will enable the capability to communicate specific information to customers through a variety of mediums like Web, mobile devices and in-home displays.

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 already underway, 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.

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 cycles, and which systems deliver the greatest immediate value to our customers, critical business functions, along with smart grid. Equally germane to this assessment process is budgeting/funding and taking into account the constraints of rate structure objectives.

Finally, PSE's information technology approach to the smart grid requires interoperability for systems, networks, and edge and end 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.

AREA: INFORMATION TECHNOLOGY

Project: Upgrade Energy Management System (EMS)

Project Description (including goal/purpose of technology): The purpose of this project is to upgrade EMS to a newer version of EMS provided by Alstom 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 is currently in progress.

Other high-level strategic objectives of the project include:

- NERC compliance/security – This upgrade will satisfy the NERC Advisory.
- Reliability/Security – Upgrading EMS will increase overall system reliability & security.
- PSE's EMS Platform software consistency – Currently PSE's three environments contain varying versions of energy management system applications. Upgrading to common and current versions will contribute to a consistent and supportable architecture.
- Hardware refresh – Upgrading outdated hardware will increase performance, security and reliability.
- Newer software version accommodation – This will lay the foundation for future enhancements of software which will meet PSE's future business needs and EMS architectural and enhancements roadmap.

After careful evaluation of PSE's business and operational needs, additional functionality was added to the original scope of this project. In Release 2, new functionality, including expansion of the network model to allow better results of the Contingency Analysis and State Estimator, will provide an overall enhanced solution to safely and reliably manage PSE's power grid.

Accomplishments to Date: Release 1 of the upgraded EMS was completed in 2012 and deployed in a state-of-the-art data center located in Bothell. The project was completed according to the following schedule:

- The new EMS system was designed and configured on new software version by Q4, 2011.
- System testing was completed in Q1, 2012.
- User acceptance testing was completed, and Release 1 was deployed in Q2, 2012.

Total Estimated Costs: $11 - 11.5 million (budget was increased to accommodate additional functionality with Release 2).

Benefits/Considerations (cost-effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations): This upgrade enables PSE to stay current with existing and future NERC and FERC Cyber Security Advisories. It will also increase efficiencies by reducing manual processes and increasing system automation, both of which will improve PSE's ability to avoid and/or quickly restore transmission outages. Additionally, improved network and SCADA model data collection capabilities will provide added safety of field crews by enabling better information about the status of grid equipment and devices.

AREA: INFORMATION TECHNOLOGY

Project: Upgrade Meter Data Management System (MDMS)

Project Description (including goal/purpose of technology): The purpose of this project is to upgrade PSE's existing Ecologic Analytics MDMS (version 2.8.3) to the most current version (version 3). This smart grid-ready system is Common Information Model (CIM) compliant and enables integration with other critical applications.

- MDMS V3 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 OMS integration to provide complete customer data from OMS 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: PSE created a business plan and submitted the project for prioritization.

Next Steps: Implementation of the project is planned for 2014.

Total Estimated Costs: $0.8 million.

Benefits/Considerations (cost-effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations): The new system will provide enhanced data to the OMS system allowing for quicker restorations. CIM compliance provides for future integration of advanced meters from AMI meter read providers, with minimal integration costs. Customer experience will be enhanced because the MDMS V3 user interface provides a quicker response for meter data queries (from 45 seconds to less than 10 seconds), reducing call length. 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 also be available. This upgrade will also enhance safety with the ability for AMR messaging received by the OMS system to enable field crews to have more up to date information on the status of restorations and energized lines due to customer generation.

AREA: INFORMATION TECHNOLOGY

Project: Electric Geospatial Information System (GIS)/Outage Management System (OMS)

Project Description (including goal/purpose of technology): The goal of the electric GIS/OMS project is to substantially improve PSE's customer service, outage management, data collection and analysis and reliability reporting beyond what is possible with the current systems and processes. PSE's implementation plan calls for the installation of General Electric's electric GIS (Small World) and OMS (PowerOn) solutions. Implementation of GE's systems will enable the replacement of several existing systems that are becoming obsolete or are inconsistent with PSE's IT strategy.

The electric GIS moves PSE from static mapping to a system that maintains the geospatial and connectivity data for PSE's electric field assets. With this in place, the OMS will fulfill a number of new functions including:

- Improved outage prediction and switching.
- 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 the mobile workforce solution.
- Integration with PSE's asset management tools so that staff is able to track all changes to the network and maintain the data quality of the network.

Accomplishments to Date: PSE opted to separate the implementation of DMS from OMS while General Electric made significant revisions to the product. In Q1, 2012, PSE went live with a release of the electric GIS product, providing the network model for the OMS and enabling acquisition of the electric network data from the field. PSE deferred the electric GIS/OMS go-live date to 2013 to allow for more fully developed foundational data competencies and ensure system readiness by the 2013-2014 storm season.

Next Steps: Implementation of the new electric GIS/OMS is expected to be complete in 2013. PSE is in early planning for integration of OMS with PSE's new CIS, MDMS and new DMS.

Total Estimated Costs: $40 million.

Benefits/Considerations (cost-effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations): PSE customers will experience improved outage and restoration communications and, on average, shorter outage durations with the new OMS, thus resulting in improved customer service and satisfaction. Efficiencies will be gained with more accurate and effective outage communications, particularly during major event storm response and communications, and workforce productivity will increase through improved processes and technology. PSE will also be able to source better data and analysis for more effective asset management programs. Additionally, system operators and field staff will have up-to-date maps representing the current/actual network configuration and better visibility of crew locations, improving the safety of PSE crews and customers during outages and daily switching events.

AREA: INFORMATION TECHNOLOGY

Project: Customer Information System (CIS) Renewal/Replacement

Project Description (including goal/purpose of technology): The purpose of the CIS renewal/replacement project is to replace the existing CIS application (CLX) with SAP's CR&B CIS package. As part of this project PSE will:

- Replace the current, outdated, customized mainframe CIS with a modern CIS on an industry standard platform.
- Migrate existing CLX customer data to the new CIS application.
- Deliver optimized business processes.
- Implement a CIS business intelligence solution which will provide PSE near real-time access (including ad hoc access) to CIS data.
- Allow PSE to utilize new and upgraded billing and reporting capabilities.
- Lay the foundation for future customer facing smart grid applications.

Accomplishments to Date: Project formation and design were completed in early 2012. PSE is currently in the implementation phase.

Next Steps: The project is expected to go live with system stabilization completed in 2013.

Total Estimated Costs: Approximately $80 million.

Benefits/Considerations (cost-effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations): The CIS project will continue to improve timely and accurate bills, reports and queries that adhere to regulatory compliance. It will also immediately enable PSE to offer tailored communications to specific customers based on their needs and eventually allow PSE to provide customers with a variety of new service options. Additionally, higher system up-times are expected and PSE will not have to rely on third parties for hosting or system modifications, reducing IT maintenance costs. The new CIS system will provide more efficient self-service, better reporting capabilities and increased standardization and automation of processes, all of which are expected to enable greater efficiency and quality control. Synergies with OMS and GIS will also allow outage and safety information to be communicated to customers more quickly and comprehensively.

AREA: INFORMATION TECHNOLOGY

Project: Gas Geospatial Information System (GIS)

Project Description (including goal/purpose of technology): PSE implemented a Geospatial Information System (GIS) to assist in the management and control of the gas distribution network. This system is based on the Gas Distribution Office product, part of the SmallWorld for the Utilities product suite from General Electric. It will be used to provide mapping, location and network management functionality for PSE's natural gas distribution network.

The implementation of this product provides a significant increase in functionality of PSE's existing static mapping system, providing easier access to network asset location and characteristics. This enables PSE's gas distribution network to be managed and maintained more safely and effectively, thus increasing network reliability and delivering greater levels of service to PSE's natural gas customers.

Accomplishments to Date:

- An initial release of the Gas GIS system was completed in Q4, 2011.
- During first half of 2012 new data was acquired into the system.
- PSE has targeted that by September 2012, legacy map and service card data will reside in the new GIS system.

Next Steps: Consider implementing further business focused analysis and management applications that leverage the gas network data to improve efficiency, reliability and safety.

Total Estimated Costs: $13.7 million.

Benefits/Considerations (cost-effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations): PSE employees are able to use GIS data to query, view, and share asset data company-wide. With ready access to computerized asset data, PSE can operate its business more effectively for the benefit of our customers. For example, the Gas GIS system is helping the company to more quickly and accurately identify the location of outages, meaning repair crews can be dispatched to an area more quickly. Additionally, PSE is better able to quickly assess the scope of an outage, identify its impact on customers, and proactively communicate this information to customers, thus improving service quality and satisfaction. GIS data allows PSE to more easily prioritize maintenance projects, efficiently and proactively determine which long-term capital improvements need to be made to ensure safe and dependable utility service – and coordinate those efforts with upgrades already being undertaken in the field. The GIS system will also be used to generate reports to comply with regulatory requirements, monitor network performance, and develop plans to mitigate threats to the network. All of this requires quick access to comprehensive and accurate data about the assets in our distribution infrastructure, their location and how they are connected.

AREA: INFORMATION TECHNOLOGY

Project: Distribution Management System (DMS)

Project Description (including goal/purpose of technology): PSE plans to implement a DMS from General Electric called GENe 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 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.

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 is expected to deploy the next release in 2013, allowing for a single user interface for OMS and DMS and enabling installation efficiencies for PSE.

Next Steps: PSE will receive the next integrated product release from GE in 2013; an implementation project schedule will then be developed.

Total Estimated Costs: TBD, based on implementation project schedule and details.

Benefits/Considerations (cost-effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations): PSE customers will benefit from the DMS with improvements in outage frequency and duration. Specifically, switching load flow analysis will allow for more frequent partial restorations, will shorten outage durations and improve SAIDI metrics and reduce lost revenue. Additionally, 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.

Efficiencies and overall safety will also be improved:

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

AREA: INFORMATION TECHNOLOGY

Project: Substation Internet Protocol (IP) Enablement

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 new IP-based communications method increases the bandwidth over the existing analog solution by two orders of magnitude and improves the availability of the entire SCADA system. The project will allow PSE to meet the NERC Reliability Standard EOP-008-01, which requires Backup Control Center (BUCC) functionality within two hours. The mandatory compliance date is 7/1/2013. In order to achieve functionality, SCADA from critical substations must be delivered to the BUCC. IP communications enables seamless delivery to both the Primary Control Center and BUCC.

This project will consist of several technology upgrades including replacement of the existing SCADA communications infrastructure, telecom transport improvements, implementation of Fiber Isolation, DC Power Plant upgrades, installation of network cabinets, Communication Shelters, network routers & switches, upgrading the MAS Master & Remote Radios, and the installation of a separate computer network to handle operational data.

Initially slated for 10 (two included in proof of concept) substations, this project has been expanded to include the 24 additional substations that require EOP-008-01 compliance.

Accomplishments to Date:

- PSE continues to extend fiber optic cabling throughout the T&D network.
- Hardware and facilities standards were identified, including routers, SCADA remote terminal units (RTU), analog-to-IP converters, emergency power systems and new communications structures in 2010.
- IP SCADA was implemented at the following substations: Juanita, North Bellevue in 2010 (as proof of concept), and Boeing Aerospace, Horse Ranch, Viking, Dodge Junction, Phalen Gulch, Greenwater and Yelm in 2011. In addition, IP SCADA was implemented at Ardmore, Alderton, Novelty Hill, Van Wyck, Enumclaw and Moorlands in 2012.
- Build out of the Operations Network core was completed by the end of 2011 providing a platform for IP delivery.
- PSE conducted an evaluation of IP radio technology; further analysis needs to be completed before a product recommendation can be made.

Next Steps:

- PSE is currently implementing SCADA using IP technology for any new substations (or those with major rebuilds).
- Implement SCADA using IP technology at substations that do not currently meet EOP-008-01 requirements by mid-2013 and other chosen substations that require back-up control center (BUCC) communications.
- Build out of the Operation's Network Distribution Tier by end of 2012.

Total Estimated Costs: $23.1 million capital, plus $315,000 non-capital expenditures.

Benefits/Considerations (cost-effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations): The IP SCADA project, mandated by regulatory compliance, 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). This project improves PSE's ability to monitor and restore transmission outages, increases efficiencies, and enhances safety. For example, using fiber for substation communications eliminates the potential for dangerous high-voltage issues between the substation and public networks that exists with copper. The new systems will not require manual intervention to facilitate SCADA control from the BUCC. Overall, the IP system is designed to provide seamless SCADA control to critical substation communications with the loss of the Primary Control Center. Additionally, separation of the Operations and Corporate IP networks improves security and reliability.

AREA: INFORMATION TECHNOLOGY

Project: Advanced Metering Infrastructure (AMI)

Project Description (including goal/purpose of technology): The purpose of this project is to fully evaluate the technical capabilities, strategic options and associated business cases for deploying AMI technology. Today, PSE has 1.9 million AMR meters installed providing automated meter reading to support billing, to inform outage and restoration, and to 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.

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.

Accomplishments to Date: In 2011, PSE renegotiated our AMR vendor contract. This new contract provides several avenues of departure from AMR that will allow PSE the opportunity to migrate to AMI at our own pace. PSE has started to lay out a roadmap for introducing AMI based on plausible deployment scenarios. Finally, PSE has set up a residential smart meter in the laboratory and begun to examine the technology and integration with the MDMS.

Key findings to date:

- AMI technologies may improve outage management capabilities, if deployed.
- Peer utilities deploying AMI systems have provided a wealth of lessons that PSE has noted around customer engagement, technology capabilities, vendor strengths and weaknesses, and deployment approaches.
- PSE has noted the customer concerns about radio frequency safety, cyber security, privacy and meter accuracy with smart meters and some successful approaches to addressing these concerns. PSE has also interviewed utilities who have deployed specific capabilities or specific vendor systems to understand their approaches from a technological, economical and regulatory perspective.

Next Steps: PSE will continue to specify and quantify the benefits it intends to achieve from AMI to strengthen the business case for migrating to AMI. In parallel, PSE is demonstrating that the AMI technology can produce a meter read for billing use and anticipates performing some targeted pilots to evaluate specific applications of AMI. By 2014, PSE intends to have a technology roadmap completed and accompanying system requirements and architecture.

Total Estimated Costs: TBD, depending on scope and scale of deployment. A full deployment of AMI, replacing all of the meters, exceeds $300 million. However, targeted deployments with a more limited scope have considerably less cost.

Benefits/Considerations (cost-effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations): AMI technology, based on industry experience, is expected to provide customers with faster outage response, better information on energy consumption patterns to inform conservation actions, and new choices in products and services enabled by meter communications. Customers' energy data will continue to be collected in confidence and only shared with a third-party with explicit permission.

AREA: INFORMATION TECHNOLOGY

Project: Energy Trading and Risk Management (ETRM) System

Project Description (including goal/purpose of technology):

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, consolidating and simplifying the technology landscape. Functionality that this project is expected to deliver includes:

- Addressing the technology obsolescence by replacing the Sungard Gas Management System (GMS) application prior to the vendor's 2015 horizon.
- 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.
- Reducing or mitigating the possibility of compliance or commercial points of failure by leveraging automated checks and balances within the system.
- Automation of accounting process 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 following a 14-month formal operational RFP and feasibility process.

Next Steps: The initiative is currently awaiting funding approval to support the following implementation phases:

Phase 1 – Gas Management System and Gas for Power Replacement in 2013/2014

Phase 2 – Power Management System Replacement in 2014/2015

Phase 3 – Integrated Resource Management Analytics in 2015/2016

Total Estimated Costs: $13.6 - $15 million.

Benefits/Considerations (cost-effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations): PSE will have the ability to increase the automation of generation scheduling practices to more efficiently dispatch or displace generation in light of both reliability requirements and market opportunities. With the implementation of an ETRM system, 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; and operational controls, approvals, role-based security will be automated, making transactions easier to audit. Additionally, the system will provide the infrastructure necessary to comply with the Dodd Frank derivatives legislation, enhance operational efficiency with automated straight-through processing, and real-time information access to the Trading Operations.

Customer Information and Energy 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 easy-to-use energy management capabilities and reporting tools/information; better information through two-way automated metering technology; and other customer energy capabilities such as household energy usage and appliance monitoring and adjustment. Anticipating customer needs/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:

- Digital meters, smart thermostats and other devices that allow customers to adjust their energy consumption based upon their preferences and rates;
- 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, with the ability to change energy settings;
- 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;
- Electric plug-in 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 how they will take advantage of the levels of automation and energy management that PSE may offer. PSE's goal is to provide customers with the information and educational resources that equip customers to make informed decisions–and to run pilot projects that evaluate consumer comfort levels with new technology as well as 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 services;
- 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; and
- 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.

AREA: CUSTOMER INFORMATION AND ENERGY EMPOWERMENT

Project: My PSE Account

Project Description (including goal/purpose of technology): This project is the redesign and migration of My PSE Account into the existing PSE.com. This will provide an authenticated user experience, enhancements and additions to a variety of customer self-service features and will enable PSE for future mobile capabilities.

In 2011 an overall PSE Web strategy effort was conducted. Based on the results of the strategy, a Web strategy roadmap was generated by the end of 2011. This project is the first phase of implementing this overall roadmap.

PSE has learned from customer feedback that customers would like options for self-service and PSE is committed to providing an enhanced customer experience. PSE is also learning from PSE's own website usage analysis that more customers are moving towards mobile access.

Accomplishments to Date: PSE completed the initiation phase, requirements gathering, and initial design mid-2012, and is in the development/construction phase.

Next Steps: Completion and go live for this project is early 2013.

Total Estimated Costs: $1.2 million.

Benefits/Considerations (cost-effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations): Consolidating the technical infrastructures into a single customer facing experience will increase overall efficiencies, reduce customer care call volumes, and improve customer service. PSE customers will benefit from online self-service features, improved bill pay capabilities (including paperless bill pay options) and access to more information via mobile devices. Additionally, PSE will be able to reduce the ongoing support associated with multiple technology environments and leveraging 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 IT's direct assistance.

AREA: CUSTOMER INFORMATION AND ENERGY EMPOWERMENT

Project: PSE.com/Online tools

Project Description (including goal/purpose of technology): As part of PSE's energy efficiency program, Web-based technologies are leveraged to empower our customers with information about their energy use. PSE's AMR network enables the Web capability that allows customers to view their previous day's energy consumption. PSE provides customers with quality information that will assist them in making cost-effective decisions relative to energy efficiency investments, and motivate them to participate in eligible energy efficiency programs and services while simplifying the process to take action.

While significant improvements were made to PSE's public-facing online tools with the 2011 re-launch of PSE.com and the new Savings & Energy Center, investment in new features that provide personalized recommendations by individual account or premise were tabled at the time due to the timing of the CIS replacement. Without these technological upgrades, the information available to customers about their detailed energy usage is limited.

PSE plans to provide additional tools for our residential and business customer base, community partners and trade allies to be able take even better control of their energy use–with personalized energy management tools, targeted merchandising, self-service rebate and application transactional capabilities.

Dynamically generated content features will also allow PSE to measure, track and quantify customer browsing preferences in order to provide targeted, relevant information about energy efficiency and customer renewables, using a variety of analytical tools. These features are dependent on successful implementation of CIS and that system's integration with PSE.com, and will help PSE capitalize on advanced online marketing opportunities, using a uniquely customized and personalized merchandising approach.

Continuous improvement of these tools is necessary as PSE's technology capabilities and customer experience expectations evolve.

Accomplishments to Date: PSE has completed the technical architecture and requirements gathering for the second phase of online tools and capabilities implementation.

Next Steps: This next phase of the Web enhancement plan is scheduled to be completed in 2013.

Total Estimated Costs: As outlined in PSE's Energy Efficiency Biennial Conservation Plan filed with the UTC UE 11181 (effective January 2012, PSE's Energy Efficiency Services is known as Customer Energy Solutions) $1,456,000.

Benefits/Considerations (cost-effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations): 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.

With enhanced online tools, PSE expects to better grow energy efficiency program participation, generate awareness, reach out to customers and community, enable and empower self-service energy management, energize trade-ally and community distribution networks, and create stakeholder engagement and community.

AREA: CUSTOMER INFORMATION AND ENERGY EMPOWERMENT

Project: Home Energy Report

Project Description (including goal/purpose of technology): The Home Energy Report pilot is a low-cost/no-cost behavioral modification energy savings project that provides home energy reports to 38,000 gas and electric single-family customers. Originally started as a pilot (2008-2011), this program is being implemented to test the durability and longevity of energy savings. 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 (geographic information system) 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.

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.

Accomplishments to Date: Completed pilot in 2011 with successful results.

Next Steps: Continue to offer Home Energy Reports to 24,000 customers to test the durability and longevity of energy savings through 2013.

Total Estimated Costs: As outlined in PSE's Energy Efficiency Biennial Conservation Plan filed with the UTC UE 11181 (effective January 2012, PSE's Energy Efficiency Services is known as Customer Energy Solutions) $630,000 (2012-2013).

Benefits/Considerations (cost-effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations): This program is designed to gain knowledge of customer acceptance, energy savings potential, and the persistence of savings. Customers benefit with energy savings through behavior modification.

AREA: CUSTOMER INFORMATION AND ENERGY EMPOWERMENT

Project: Customer Energy Generation (Distributed Generation [DG])

Project Description (including goal/purpose of technology): At the end of 2011, PSE had 1,010 net-metered customers, most of whom own residential solar PV systems. These 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. PSE must ensure that customers are interconnected while meeting standards for safety and reliability.

As the number of net-metering customers grows, so does the need for automation and increased process efficiencies. Every month the bills of net-metering customers are pulled and adjusted by hand to account for the energy their systems put back into the grid. Once per year, PSE must calculate the annual production from each customer's system and then distribute payment accordingly. This is currently a manual process. During outages, crews are expected to lock out each known system individually.

With the foundational systems currently being implemented (as noted in the IT section), many of the net-metering processes, including monthly billing, will be automated. These systems will also allow for improved tracking of payments and locations.

Accomplishments to Date:

- The number of customers producing electricity increased by 29 percent in 2011. All systems that can feed electricity into PSE's distribution network are known and mapped by location, technology and capacity.
- New customer interconnection process improvements for systems <100kW have been made to simplify customer applications and interconnection.
- Application and interconnection process improvements for 100kW to 20MW projects continue to be ongoing.
- The renewable generation section of PSE.com site was expanded to include net metering, production metering and local energy development.

Next Steps:

- Anticipate and support continued rapid program growth (4,500 net-metered customers are projected by the end of 2017).
- Implement automated monthly billing and improved payment and location tracking.
- Consider opportunity for pilot projects involving sophisticated meters and direct-to-customer-computer/smart phone messaging

Total Estimated Costs: $700,00 over two years

Benefits/Considerations (cost-effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations): Automating the net-metering processes/billing will increase accuracy, improve customer service and reduce overall costs associated with the currently existing manual processes. In addition, most of the discussion around the impact of solar power systems on PSE's local distribution system is theoretical. Knowing the location of each solar power system, down to the circuit, allows us to determine the real effects as capacity grows. This will allow upgrades to be made with better knowledge and results.

AREA: CUSTOMER INFORMATION AND ENERGY EMPOWERMENT

Project: Plug-in Electric Vehicles (PEVs)

Project Description (including goal/purpose of technology): The purpose of this project is to ensure that PSE is prepared for, and encourages the arrival and adoption of mass-market PEVs. While PSE's research over the past two years shows PEVs pose minimal impacts to generation and transmission in the short run, distribution system impacts are small but significant, however, they are 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 all PSE customers.

It is important to note that PEV rollout has been slower than expected and customer adoption has been lower than industry forecasts. However it is too early to conclude what the long-term adoption will be. PSE remains optimistic that PEVs will be successful, even as it remains a niche market for several years.

Overall, smart-grid related efforts in this arena still appear premature. Automakers are reluctant to engage in vehicle-to-grid discussions, and other tactics to reduce peak load, such as TOU pricing, are likely to be more cost-effective in the short-run.

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 (1 Chevrolet Volt, 2 Nissan Leaf, 1 Toyota Prius Plug-In retrofit).
- PSE is working closely with entities/partners working to site and interconnect public PEV charging infrastructure.
- Participation on the State PEV Task Force.

Next Steps:

- Continue to monitor and study real-world charging data from sources like "The EV Project" to understand in greater detail the impacts from PEV loads. Use this data to ensure that distribution upgrades are being made to avoid potential system failures.
- Include additional demonstration PEVs in the company fleet with a particular focus on high-usage trucks and vans.
- Perform a comprehensive and detailed analysis of the feasibility and cost-benefit of various tactics to reduce the peak load impacts from PEVs (TOU pricing, "smart charging," etc.)
- Continue to assist our customers by answering PEV-trelated questions and efficiently handling interconnection requests and post-installation support.

Total Estimated Costs: PSE anticipates spending approximately $200,000 per year in O&M and $30,000 in capital on PEV readiness activities annually for the next 1-3 years.

Benefits/Considerations (cost-effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations):

- PEV customers benefit from lower fuel costs, but in PSE's analysis, 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 PEV incentives.
- PEV customers do 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. 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 pressure.
- PEVs reduce air pollution and CO2 emissions, 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.

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 and that embody smart grid. Critical environmental factors considered in our two-year and future plans include:

- Upgrading and replacing aging T&D infrastructure and components, as well as IT hardware and end use systems, for greater system reliability and efficiency, and to enable future smart grid applications;
- Updating or installing smarter components as new sources of renewable energy 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, as new and enhanced delivery systems are introduced;
- 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, which enforces regulations for the reliability of the bulk power system in North America, in the context of smart grid.

AREA: TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE

Project: Transmission Automation and Reliability

Project Description (including goal/purpose of technology): PSE's transmission automation and reliability work focuses on the incremental improvement of the smart transmission system through replacement of aging infrastructure and technologies, and addition of new smart grid functionality, such as 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 which 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 closed) 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 PSE's 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.

It's important to note, this upgrade/replacement work typically comes with extended project timelines. Project work is dependent on several factors such as planning and coordinating transmission line outages to minimize risk to the transmission system. Installation times can also be affected by having to coordinate potential outages with customers (to minimize risk of a service interruption).

Accomplishments to Date: In 2010, PSE installed supervisory control on 115 kV transmission line switches located within Enterprise Substation in Ferndale. And in 2011, PSE installed supervisory control on 115 kV transmission line switches located within the Olympic Renton Substation in Renton. In both cases, the switches already had automatic controls but did not have supervisory control. Also in 2011, new automatic and supervisory control was installed on 115 kV transmission line switches located on the Enserch-Bellingham #1 115 kV line in Bellingham and made operational in first quarter 2012.

Next Steps: Supervisory control will be added to a 115 kV transmission line switch on Mercer Island, WA that already has automatic control. PSE continuously reviews its trans¬mission system for new automatic switch schemes opportunities and improvements to existing schemes, as well as any needed upgrades or replacements of aging schemes. Usually one or two new schemes or improvements of existing schemes are planned to be completed each year.

Total Estimated Costs: $400,000 - 1.5 million annually.

Benefits/Considerations (cost-effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations): Automatic control of transmission line switches reduces customer service interruption duration times. More specifically, expected service improvement for customers fed by substations in unfaulted line sections can be reduced from 60 minutes or longer without automatic control to less than a minute with automatic control. (The 60 minutes is the estimated time it takes to become aware of a problem, to send a service lineman out to do a patrol and identify and communicate the problem back to the System Operator and then to actually do the switching to isolate the faulted line section.) Supervisory control of transmission line switches enables better situational awareness for the System Operators (status of switch, open or closed) and provides the Operator with remote control of the switches.

AREA: TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE
Project: Distribution Automation - Large Customer Campus
Project Description (including goal/purpose of technology): The large customer campus SCADA switches still consist of 42 switches as reported in 2010. Expanding the number of SCADA switches is dependent upon support by this large customer's desire and budget.
Accomplishments to Date: 42 SCADA switches are operational with over half of them pre-programmed with an automated restoration scheme as requested by the large customer.
Next Steps: Continue to monitor the system to help determine the infrastructure improvements that may be needed to enhance the reliability of the system that serves the large customer.
Total Estimated Costs: No changes or expansion of this system is currently in the plans for the next several years. (Note, all of the upgrade costs for SCADA and automation have been paid for by this customer requesting them.)
Benefits/Considerations (cost-effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations): Provides real-time loading of sections of the circuits with SCADA which gives Planning and System Operations valuable load information for operating and planning future capacity decisions. 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.

AREA: TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE

Project: Distribution Recloser Program

Project Description (including goal/purpose of technology): Like most utilities pursuing significant reliability improvements on the distribution system, PSE has continued to install three phase reclosers to reduce the impact of outages on the feeders to our customers. In 2009, PSE initiated the Distribution Recloser Program to install more reclosers on the system with the goal of having at least one recloser on the overhead circuits where customers would benefit from the installation.

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 not requiring the station circuit breaker to lock out and interrupt service to all the customers on the feeder. Instead, with the installation of reclosers, only ½ or less customers are impacted.

In addition, PSE will be evaluating and piloting the installation of line reclosers with communication used for remote monitoring and control of the device. This will help determine the challenges and benefits in using the recloser as a device as part of distribution automation. It is anticipated that greater outage duration will be saved for customers when the System Operators can remotely operate and control the reclosers.

While anticipated customer benefits are great, the biggest challenge for reclosers with communication has been communications feasibility. Future projects should have a feasibility review to determine the best communications solution for the site, such as SCADA control of reclosers for which there is strong support. Consideration may be needed for how to integrate these and other SCADA enabled devices into the new Outage Management system.

Accomplishments to Date: As of the end of 2011, PSE installed more than 500 reclosers on our overhead distribution circuits – more than 140 of which were installed during the past three years. Three of the reclosers were installed with communication for remote monitoring and control.

Next Steps: 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: $2 million annually over the next two years.

Benefits/Considerations (cost-effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations): 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 instant notification of recloser operations and the ability to restore an outage remotely after the line has been patrolled and cleared. 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. There are planning benefits due to the information received which provides 3 phase ampere data at a location on the circuit which allows for better system modeling and decision making.

AREA: TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE

Project: Distribution Supervisory Control and Data Acquisition (SCADA) Program

Project Description (including goal/purpose of technology): SCADA is a system used to monitor and control substation equipment. Key information, such as circuit breaker status and transformer loading, can be obtained almost instantly and transmitted to PSE's Control Area operations center. 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.

The 24/7 data from SCADA provides planners with information used for every day planning, not just peak load-related planning. This information is used for load, reliability and outage studies.

Accomplishments to Date: PSE has been installing and upgrading the SCADA system in PSE-owned distribution substations to better monitor and control substation equipment and the distribution system. Since 2010, three substations have been added to PSE's SCADA system, providing coverage of 98 percent of PSE distribution substations. Monitoring of three-phase amps has been upgraded in 27 substations (87 percent coverage in 2012, up from 77 percent in 2010) and distribution breaker supervisory control has been upgraded in six substations (19 percent coverage in 2012, up from 17 percent in 2010).

Next Steps: For all new distribution substations, PSE is installing SCADA to operate and control substation equipment as well as monitoring the equipment. By 2015 SCADA improvements will be made at 31 of the substations and one more station will have SCADA installed. New distribution circuit breakers with supervisory control will be installed at these stations.

Total Estimated Costs: $3 million over the next two years.

Benefits/Considerations (cost-effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations): Customers benefit from PSE's Distribution SCADA Program by experiencing improved reliability of the electric system. Projects funded by this program are identified each year with specific benefits and costs, with an overall benefit of improved system reliability through a reduction in outage duration and improvement in SAIDI.

AREA: TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE

Project: Remote Data Acquisition Devices (RDADs) Pilot

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

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 that gave hourly snapshot load readings. They also integrated Verizon technology into the units, allowing PSE to work with our preferred provider.
- Determined integration requirements with PSE's new EMS. The decision was made not to connect to the PSE system until the new DMS system is developed. An alternative plan to use Coopers Web hosting product was examined and selected.
- 60 RDADs were installed in 20 switch locations to determine compatibility with existing switch gear and communication via cell phone text signal. Of the 60 units, 59 are functioning as expected and PSE is obtaining data. Further work is being done to determine the problem with the final unit.

Next Steps:

- Further installations on other locations within the Bellevue Central Business District (up to 50 locations) to further explore different installation options with a variety of equipment PSE has in the field.
- Determine what will be needed to incorporate this equipment onto PSE's new DMS system.
- Deploy RDADS into parts of PSE's service area where access is limited.

Total Estimated Costs: $200,000 over the next two years.

Benefits/Considerations (cost-effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations): 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.

AREA: TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE

Project: Distribution Automation - Bellevue Central Business District (CBD)

Project Description (including goal/purpose of technology): To serve areas with very high density load requires many switches placed in close proximity to each other, primarily in the sidewalks along busy streets. Performance of normal or emergency switching requires servicemen to commute through high traffic areas and access vaults in the sidewalk, interrupting pedestrian traffic. The purpose of this project is to determine what is necessary to install Supervisory Control And Data Acquisition Control (SCADA) infrastructure in distribution switch gear. The current project scope is to replace the existing manual switches on two circuits within the CBD with SCADA switches. PSE will then connect the controllers of these switches with fiber optic cables and build an interface with the EMS system. Once complete and the system is fully operational, PSE will continue to implement an automation control system that will analyze site data, isolate problems, and restore electricity to customers.

Accomplishments to Date: PSE is working with the manufacture to configure switches to fit with existing vaults. Standards for fiber optic construction in a 12.5 kV power systems are being developed. PSE is also proofing the conduits and vaults within the City of Bellevue to validate the pathway and investigating available automation programs.

Next Steps:

- Finalize a SCADA solution for Vista switches in existing vault locations.
- Define what new construction standards are required for future installations.
- Replace switches in the reliability ring to monitor unloaded back-up circuits for the management of outage restoration.
- Replace load switches in key locations to facilitate automatic switching due to bank outages.
- Continue to replace load switches to allow for further segmentation and isolation of problems that may occur.
- Evaluate and select distribution automation program.

Total Estimated Costs: $2 million annually over the next two years.

Benefits/Considerations (cost-effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations): PSE expects to reduce outage durations by having the ability to restore systems remotely. There will also be less impact on traffic and pedestrians in the dense downtown area of Bellevue because each site will not need to be visited by a service lineman. The upgraded system will also provide real time distribution information to operations and planning enabling optimized system performance. It is important to note that communications methods using fiber use different modes of operation and not all software will accommodate current PSE IT standards. In addition, PSE will also need to gain approval from the City of Bellevue Permitting Group to construct/up¬grade electric equipment within PSE's easement in Bellevue's CBD.

AREA: TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE
Project: Conservation Voltage Reduction (CVR)
Project Description (including goal/purpose of technology): CVR is the practice of lowering the feeder voltage at the substation and line regulators in order to reduce electric power consumption. PSE traditionally has set the feeder voltage within the mid to higher range of the ANSI standard. However, a study completed by 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 develop an initial program to implement CVR on three substations by the end of 2013 and three to six more substations in 2014. The nine proposed substations were selected mainly for their residential loading. Once implemented, PSE will continue monitoring the system and making adjustments to the CVR settings as needed to ensure our customers continue to receive great service.
Accomplishments to Date: PSE completed analysis of 12 substations and expects to complete CVR and start implementation and documentation of the energy savings on three of these substations by the end of 2013. With lessons learned from 2013, a similar process will be applied in 2014.
Next Steps: PSE plans to implement CVR on three substations by the end of 2013 and three to six additional substations by the end of 2014. PSE will use smart meters to monitor end-of-line voltage for these sites.
Total Estimated Costs: $300,000 to $500,000 (two year budget).
Benefits/Considerations (cost-effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations): Applying the specific CVR method LDC will lower customer energy bills and minimize voltage fluctuations, as well as generally decrease the system VARs. Phase balancing improves the health of the system by decreasing neutral current and minimizing losses. Implementing CVR will improve the efficiency of selected distribution circuits. Improving distribution efficiency will aid in reducing electric power consumption, decreasing the peak demand, and the decrease of system losses.