e-FILING REPORT COVER SHEET

Send completed Cover Sheet and the Report in an email addressed to:
PUC.FilingCenter@state.or.us

REPORT NAME: 2014 Smart Grid Report

COMPANY NAME: Portland General Electric

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☒No ☐Yes

If yes, please submit only the cover letter electronically. Submit confidential information as directed in OAR 860-001-0070 or the terms of an applicable protective order.

If known, please select designation: ☒RE (Electric) ☐RG (Gas) ☐RW (Water) ☐RO (Other)

Report is required by: ☐OAR Enter rule number

☐Statute Enter Statute

☒Order Order No. 12-158

☐Other Enter reason

Is this report associated with a specific docket/case? ☐No ☒Yes

If yes, enter docket number:

List applicable Key Words for this report to facilitate electronic search:
Smart Grid Report

DO NOT electronically file with the PUC Filing Center:

- Annual Fee Statement form and payment remittance or
- OUS or RSPF Surcharge form or surcharge remittance or
- Any other Telecommunications Reporting or
- Any daily safety or safety incident reports or
- Accident reports required by ORS 654.715

Please file the above reports according to their individual instructions.

Portland General Electric Company
121 SW Salmon Street • Portland, Oregon 97204
PortlandGeneral.com

May 30, 2014

Via Email
puc.filingcenter@state.or.us

OPUC Filing Center
3930 Fairview Industrial Dr., SE
PO Box 1088
Salem, OR 97308-1088

RE: **2014 Smart Grid Report**

Commission Order No. 12-158 (Docket No. UM 1460) directed PGE to submit annual reports beginning June 2013, regarding our strategy, goals and objectives for adoption of smart grid technologies and the status of our smart grid investments. In addition, PGE was required to provide opportunities for the public to contribute input on PGE's smart-grid investments and applications.

In formulating PGE's 2014 Smart Grid Report, on April 15, 2014, PGE held a Smart Grid workshop to receive and consider feedback from stakeholders on PGE's 2014 Smart Grid Draft Report. Pursuant to Order No. 12-158, PGE provides the attached 2014 Smart Grid Report.

If you have any questions or require further information, please call Spenser Williams at (503) 464-7490. Please direct all formal correspondence and requests to the following email address: pge.opuc.filings@pgn.com.

Sincerely,

Patrick G. Hager, III
Manager, Regulatory Affairs

cc: UM 1460 Service List
UM 1657 Service List
UE 283 Service List
LC 56 Service List

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused **PORTLAND GENERAL ELECTRIC COMPANY'S ANNUAL SMART GRID REPORT** to be served by electronic mail to those parties whose email addresses appear on the attached service lists for OPUC Dockets No. UM 1460/UM 1657/UE 283/LC 56.

DATED at Portland, Oregon, this 30th day of May, 2014.

Patrick G. Hager III
Manager, Regulatory Affairs
Portland General Electric Company
121 SW Salmon St., 1WTC0702
Portland, OR 97204
(503) 464-7458 Telephone
(503) 464-7651 Fax
patrick.hager@pgn.com

SERVICE LIST – 5/30/14
OPUC DOCKET UM 1460

Renee M. France DEPARTMENT OF JUSTICE Natural Resources Section renee.m.france@doj.state.or.us	Kacia Brockman OREGON DEPARTMENT OF ENERGY kacia.brockman@state.or.us
Gordon Feighner CITIZENS' UTILITY BOARD OF OREGON gordon@oregoncub.org	Robert Jenks CITIZENS' UTILITY BOARD OF OREGON bob@oregoncub.org
G. Catriona McCracken CITIZENS' UTILITY BOARD OF OREGON catriona@oregoncub.org	Keith Kueny COMMUNITY ACTION PARTNERSHIP OF OREGON keith@caporegon.org
John M. Volkman ENERGY TRUST OF OREGON john.volkman@energytrust.org	John Cooper GRID NET john@grid-net.com
Christa Bearry IDAHO POWER COMPANY cbearry@idahopower.com	Jan Bryant IDAHO POWER COMPANY jbryant@idahopower.com
Lisa D. Nordstrom IDAHO POWER COMPANY lnordstrom@idahopower.com	Michael Youngblood IDAHO POWER COMPANY myoungblood@idahopower.com
Adam Lowney MCDOWELL, RACKNER & GIBSON, PC adam@mcd-law.com	Wendy McIndoo MCDOWELL, RACKNER & GIBSON PC wendy@mcd-law.com
Lisa F. Rackner MCDOWELL, RACKNER & GIBSON, PC dockets@mcd-law.com	Wendy Gerlitz NW ENERGY COALITION wendy@nwenergy.org
Jess Kincaid OREGON DEPARTMENT OF ENERGY jess.kincaid@state.or.us	Michelle R. Mishoe PACIFIC POWER AND LIGHT michelle.mishoe@pacificorp.com
Doug Marx PACIFICORP douglas.marx@pacificorp.com	Oregon Dockets PACIFICORP DBA PACIFIC POWER oregondockets@pacificorp.com
John Cooper GRID NET john@grid-net.com	Maury Galbraith OREGON PUBLIC UTILITY COMMISSION maury.galbraith@state.or.us
Michael T. Weirich, Assistant AG DEPARTMENT OF JUSTICE michael.weirich@state.or.us	Robert Frisbee SMART GRID OREGON rfrisbee@si-two.com
Roy Hemmingway SMART GRID OREGON royhemmingway@aol.com	Phil Keisling SMART GRID OREGON pkeisling@gmail.com
Barry T. Woods SMART GRID OREGON/ECOTALITY COUNCIL woods@sustainableattorney.com	Elaine Prause ENERGY TRUSY OF OREGON elaine.prause@energytrust.org

Jay Tinker PORTLAND GENERAL ELECTRIC pge.opuc.filings@pgn.com	Richard George PORTLAND GENERAL ELECTRIC richard.george@pgn.com

SERVICE LIST 5/30/14
OPUC DOCKET # UE 283

Judy Johnson **(C)** PUBLIC UTILITY COMMISSION OF OREGON judy.johnson@state.or.us	Stephanie S. Andrus **(C)** PUC – DEPARTMENT OF JUSTICE stephanie.andrus@state.or.us
Douglas C. Tingey **(C)** PORTLAND GENERAL ELECTRIC COMPANY doug.tingey@pgn.com	Jay Tinker **(C)** PORTLAND GENERAL ELECTRIC COMPANY pge.opuc.filings@pgn.com
OPUC Docket CITIZENS' UTILITY BOARD OF OREGON dockets@oregondub.org	Robert Jenks **(C)** CITIZENS' UTILITY BOARD OF OREGON bob@oregoncub.org
G. Catriona Mccracken **(C)** CITIZENS' UTILITY BOARD OF OREGON catriona@oregoncub.org	Greg Bass **(C)** NOBLE AMERICAS ENERGY SOLUTIONS gbass@noblesoultions.com
Kevin Higgins ENERGY STRATEGIES LLC khiggins@energystrat.com	Gregory Adams RICHARDSON ADAMS PLLC greg@richardsonadams.com
S Bradley Van Cleve **(C)** DAVISON VAN CLEVE PC bvc@dvclaw.com	Tyler C. Pepple DAVISON VAN CLEVE PC tcp@dvclaw.com
Bradley Mullins **(C)** DAVISON VAN CLEVE PC brmullins@mwanalytics.com	E-Filing NORTHWEST NATURAL efiling@nwnatural.com
Mark Thompson NORTHWEST NATURAL mark.thompson@nwnatural.com	Wendy Gerlitz NW ENERGY COALITION wendy@nwenergy.org
Nona Soltero FRED MEYER STORES/KROGER Nona.soltero@fredmeyer.com	Sarah Wallace PACIFIC POWER Sarah.wallace@pacificorp.com
David Tooze CITY OF PORTLAND David.tooze@portlandoregon.gov	Oregon Dockets PACIFICORP, DBA PACIFIC POWER oregondockets@pacificorp.com
Kurt Boehm BOEHM KURTZ & LOWRY kboehm@bkllawfirm.com	Jody Cohn BOEHM KURTZ & LOWRY jkyler@bkllawfirm.com
Benjamin Walters CITY OF PORTLAND Ben.walters@portlandoregon.gov	Doug Tingey PORTLAND GENERAL ELECTRIC doug.tingey@pgn.com
Jay Tinker PORTLAND GENERAL ELECTRIC pge.opuc.filings@pgn.com	

SERVICE LIST – 5/30/14
OPUC DOCKET # LC 56

Kacia Brockman OREGON DEPARTMENT OF ENERGY kacia.brockman@state.or.us	Phil Carver OREGON DEPARTMENT OF ENERGY phil.carver@state.or.us
Renee M. France OREGON DEPARTMENT OF JUSTICE Renee.m.france@doj.state.or.us	OPUC Dockets CITIZENS' UTILITY BOARD dockets@oregoncub.org
G. Catriona McCracken CITIZENS' UTILITY BOARD catriona@oregoncub.org	Robert Jenks CITIZENS' UTILITY BOARD bob@oregoncub.org
Tyler Pepple DAVISON VAN CLEVE tcp@dvclaw.com	S. Bradley Van Cleve DAVISON VAN CLEVE bvc@dvclaw.com
John Crider PUC STAFF--DEPARTMENT OF JUSTICE john.crider@state.or.us	Michael T. Weirich PUC STAFF--DEPARTMENT OF JUSTICE michael.weirich@state.or.us
Wendy Gerlitz NW ENERGY COALITION wendy@nwenergy.org	Ralph Cavanagh NATURAL RESOURCES DEFENSE COUNCIL rcavanagh@nrdc.org
Angus Duncan NATURAL RESOURCES DEFENSE COUNCIL angusduncan@b-e-f.org	RNP Dockets RENEWABLE NORTHWEST PROJECT dockets@rnp.org
Megan Walseth Decker RENEWABLE NORTHWEST PROJECT megan@rnp.org	Patrick Hager PORTLAND GENERAL ELECTRIC patrick.hager@pgn.com
V Denise Saunders PORTLAND GENERAL ELECTRIC denise.saunders@pgn.com	John Lowe RENEWABLE ENERGY COALITION jravenesanmarcos@yahoo.com
James Brirkelund SMALL BUSINESS UTILITY ADVOCATES james@utilityadvocates.org	

SERVICE LIST
OPUC DOCKET # UM 1657

OPUC Dockets CITZEN'S UTILITY BOARD OF OREGON dockets@orgegoncub.org	Robert Jenks CITZEN'S UTILITY BOARD OF OREGON bob@oregoncub.org
Wendy Gerlitz NW Energy Coalition wendy@nwenergy.org	Rates & Regulatory Affairs PORTLAND GENERAL ELECTRIC pge.opuc.filings@pgn.com
Patrick Hager PORTLAND GENEERAL ELECTRIC pge.opuc.filings@pgn.com	J Richard George PORTLAND GENERAL ELECTRIC richard.george@pgn.com
Juliet Johnson PUBLIC UTILITY COMMISSION OF OREGON juliet.johnson@state.or.us	Michael Weirich PUC STAFF – DEPARTMENT OF JUSTICE Michael.weirich@state.or.us

Portland General Electric

Smart Grid Report

June 1, 2014

Table of Contents

1. Executive Summary

1.1 Introduction

This is the first update to the Smart Grid report Portland General Electric filed on June 1, 2013 in response to the Oregon Public Utility Commission (OPUC) Order No. 12-158 in UM 1460. In this document, we will update PGE's plans to develop a smarter grid over the next decade and share the vision of what PGE believes may be achievable over the next five years (planning period), based on the maturity of Smart Grid technologies, the value they can deliver and customer readiness.

PGE anticipates that the cost of implementing the projects and initiatives described herein will be on the order of $91 million over the planning period. Approximately $53 million of the $91 million of investments are dedicated to Smart Grid-specific projects,[1] with the remainder supporting other business improvements that also provide the necessary back-office solutions for enabling Smart Grid technologies.[2] Over the past decade, PGE has invested almost $200 million in systems and technologies, such as Advanced Metering Infrastructure (AMI),[3] Supervisory Control and Data Acquisition (SCADA), Dispatchable Standby Generation (DSG) and the Salem Smart Power Project, which support PGE's efforts to transition towards a smarter grid.

1.2 Stakeholder Involvement

In developing our initial Smart Grid Report, PGE considered feedback from customers, community and regulatory stakeholders. To understand customer desires with respect to the Smart Grid, PGE has worked with Market Strategies International to complete the Energy + Environment Study (E2 Study).[4] PGE also conducts customer research on a regular basis to ensure our vision aligns with customer expectations regarding Smart Grid engagement.

One of the suggestions made at the time the original report was filed was for PGE to allow more time for stakeholder feedback. In response to that suggestion, this year PGE began soliciting feedback from key stakeholders earlier in the process, shared a draft report one month earlier and scheduled a public workshop seven weeks ahead of the report filing date.

1.3 PGE's Smart Grid Vision

PGE envisions an end-to-end transformation of its electrical distribution system to deliver enhanced value and control to customers while allowing us to operate the system more

---

[1] $30 million for PGE's Energy Partner[SM] Demand Response Program, $12 million for DSG, $8 million for other T&D Smart Grid including SCADA expansion, $3 million for additional research, development and demonstration.
[2] $20 million in capital costs for Geographic Information System with Graphic Work Design and $18 million capital costs for Outage Management System.
[3] $153 million for AMI, $8 million on SCADA, $32 million on DSG, and $6 million on the Salem Smart Power Project.
[4] A total of 1,116 PGE online residential customer interviews were completed from May 6-13, 2013. Participants were drawn from a broad range of ages, education levels and incomes. Customers at the lower end of the income spectrum (those earning less than $40,000) comprised seventeen percent of the respondents. The responses of this group were compared against the answers from 1,004 interviews completed from December 17-27, 2012 with consumers nationwide.

efficiently, safely and reliably. The transition to a Smart Grid will be *evolutionary, not revolutionary*. Over the planning period, we anticipate the following initiatives to be the major focus of our efforts with respect to the Smart Grid:

- Leverage the replacement of four obsolete enterprise systems (Outage Management System, Geographic Information System, Customer Information System, and Meter Data Management System) with modern systems that enable Smart Grid applications.
- Build on the capabilities of the AMI system to enable demand response and pricing programs to improve asset utilization.
- Accelerate the completion of the SCADA build-out to substations, reclosers, tie switches, strategically placed sensors and faulted circuit indicators.
- Initiate research, development and demonstration (RD&D) efforts in support of Smart Grid applications and deployments.

1.4 PGE's Smart Grid Strategy

The table below compares the characteristics of the current power grid with a Smart Grid. In pursuing the enhancements discussed in this report, PGE's strategy is to continue moving its grid towards the defining features of a Smart Grid.

Smart Grid Features	
Existing Grid	**Smart Grid**
Largely Electromechanical	Increasingly Digital
One-Way Communication	Two-Way Communication
Centralized Generation	More Distributed Generation
Hierarchical Controls	Networked Controls
Few Sensors	Sensors Throughout
Human Monitoring	Self-Monitoring
Manual Intervention	Self-Correction
Failures and Blackouts	Self-Reconfiguring and Islanding
Program Dispatch	Optimized Economic Dispatch
Limited Control	Pervasive Control
Few Customer Choices	Many Customer Choices

To build into the grid the level of intelligence described above will require controls and the creation of unique software that can process large amounts of data.

Consistent with guidance from the OPUC, PGE follows these strategic principles to introduce incremental Smart Grid development:

- Enable Smart Grid capabilities when equipment fails or becomes obsolete.
- Be strategic with regard to the Smart Grid technologies pursued, looking for opportunities to provide customers with more choices, higher reliability and greater value.
- Use proven and interoperable technology as industry standards emerge (when feasible).
- Work collaboratively to demonstrate technologies in the early stages of commercialization, when those technologies address an immediate need (e.g., renewables integration) or have a particularly strong value proposition.
- Track early stage technologies through industry organizations, such as the Electric Power Research Institute (EPRI) and standards development through working groups, including the National Institute of Standards and Technology (NIST) and the Smart Grid Interoperability Panel (SGIP).

1.5 Development Process

When PGE elects to explore a selected Smart Grid technology we use a disciplined, staged approach to decision making (depicted below). Technologies are assessed at each step, based on the strategy provided in Section 1.4.

PGE conducts customer research on a regular basis to ensure customer expectations are aligned with the company's Smart Grid engagement. PGE leverages this research to inform our product and program offerings and identify ways to better engage customers in the Smart Grid. As PGE develops pilots/studies, we will share the results with OPUC staff and interested stakeholders, offering an opportunity for business cases for major investments to be vetted prior to deployment.

1.6 PGE's Smart Grid Efforts Align with our Integrated Resource Plan (IRP) Goals

In the decades ahead, the Smart Grid will support PGE's efforts to interconnect increasing amounts of variable renewable resources to our system. System operators will also be able to leverage demand-side resources to help dynamically balance supply and demand, which may ultimately mitigate the need for transmission upgrades and the development of fossil-fuel generation for load following. ***PGE foresees Smart Grid investments becoming viable alternatives to supply-side resources in the IRP, similar to the way cost-effective energy efficiency and demand response are considered as alternatives to supply-side resources.*** As such, PGE expects that many of our Smart Grid initiatives will likely be vetted during IRP public meetings.

1.7 Report Enhancements

In Order 13-311, the OPUC accepted PGE's Smart Grid Report with the following suggestions:

- Explore options for the use of our existing two-way communication platform and AMI; explicitly state whether benefits will be recognized (See Appendix A)
- Evaluate the use of Conservation Voltage Reduction (See Section 2.2, Appendix D)
- Develop a roadmap (with dates) that shows PGE plans to systematically evaluate the myriad of smart grid options available to the company (See Section 8)
- Explore traditional non-smart grid investments and applications as alternatives to smart grid investments (See Section 7.1)
- Explain how traditional demand-side management programs can be and are being integrated with smart grid initiatives (See Sections 3.1, 3.3)
- Discuss the impact of smart grid initiatives on low-income customers (See Section 3)
- Include a summary of how smart grid initiatives relate back to AMI objectives proposed in the stipulation approved by the commission in docket UE 189 (See Appendix A)
- Explain what is working and not working in current infrastructure investments

2. Grid Optimization

This section covers transmission, substation and distribution Smart Grid initiatives. In the past decade, PGE has engaged in a number of grid optimization activities that are now considered to be part of a Smart Grid. As discussed below, PGE will continue our grid optimization efforts in the areas that provide the most value to our customers and advance PGE towards a fully functioning Smart Grid.

2.1 Work to Date

Over the past 10 years, PGE has completed the following work that is foundational to our current and planned Smart Grid efforts:

- Installed more than 825,000 digital Smart Meters.
- Enhanced system efficiency and reliability by implementing:
    - An Energy Management System (EMS) for our generation and transmission system
    - SCADA at more than 70 percent of PGE substations
    - Substation automation
    - Fiber optic communication upgrades
    - Feasibility studies for Conservation Voltage Reduction (CVR)
    - Automated feeder switches on selected feeders with greater than average outage duration
    - A platform to manage intelligent electronic devices via Ethernet connection.
- Established 93 MWs of Dispatchable Standby Generation.
- Created a substantial public electric vehicle (EV) charging infrastructure.
- Built systems that utilize Smart Meter data to identify overloaded transformers and confirm outages prior to dispatching crews.

As discussed in section 1.4, these initiatives have made PGE's system more digital, more connected in terms of two-way communication and more supportive of new distributed forms of renewable-power generation. PGE continues to deploy more sensors and monitors, providing real-time assessments of grid performance and helping with grid self-monitoring and self-correction to avoid predictable faults and failures. These features boost grid reliability for our customers.

2.2 Work in Progress

PGE's grid optimization efforts are focused on completing basic, but critical, system enhancements that will allow:

- Improved visibility into PGE's system,
- Enhanced communications, monitoring and control,[5]
- Planning and implementation of platforms necessary for future grid enhancements and utilization of Smart Meter data (for example, an Outage Management System or Distribution Management System),[6] and
- Business cases to be developed for the deployment of field equipment needed to reduce line losses, outage time and improve power quality. [7]

In 2013, PGE launched a Conservation Voltage Reduction (CVR) pilot that will conclude in July 2014. This pilot seeks to validate our feasibility study findings and allow a more detailed analysis of potential benefits. Preliminary results have been encouraging, with CVR reducing customer demand and energy consumption when used as a peak shaving method or on a continuous basis. In our pilot, PGE found CVR was more beneficial in the winter due to the increase in resistive loads (e.g., electric furnaces) when compared with summer load composition. However, as shown in Appendix D, benefits were realized year-round. PGE expects to have final project results and recommendations available in November 2014.

PGE is also investigating a data-analytics platform that would allow the use of consumption information collected from the AMI system to optimize system efficiency.

2.2.1 Systems Development

PGE launched a broad initiative in 2013 to upgrade technology infrastructure and streamline work processes as a core component of our Transmission & Distribution (T&D) Transformation Project. When completed in mid-2015, the 'Next Wave Project' will replace approximately 30 antiquated enterprise systems with more efficient and integrated tools that will provide for greater automation in business processes and sharing of data across platforms. The upgraded

---

[5] PGE will continue to implement SCADA in the remaining 28 percent of our substations as the availability of engineering and field technician subject matter experts permit.

[6] Long-term, a Distribution Management System will be needed to capture operational efficiencies and to enable many distribution automation pilots.

[7] These changes anticipate the need to manage the impact of a growing population of distributed energy resources (solar generation, battery storage systems and possibly EVs) flowing power into the grid. Also, a growing number of automated re-closers will need to be installed to improve the reliability of problem feeders.

T&D systems include the following platforms that leverage PGE's investment in smart metering and are pre-requisites to implement certain Smart Grid field hardware.

- **Outage Management System (OMS)** will use input from Smart Meters and SCADA systems, in addition to customer calls, to identify interrupted circuits and model the extent of an outage. The new OMS will provide faster, more accurate information to help prioritize restoration efforts and optimize field crew deployment. Logic within the OMS will allow outage managers to selectively ping meters, or groups of meters, to confirm outages and outage restoration as well as filter out unwanted alarms and limit the number of alarms for the OMS system to analyze. Scheduled to be deployed in mid-2015, the expected capital cost of the new OMS system is $18 million.

- **Geographical Information System (GIS)** provides an accurate, as-built view of all components of the electrical grid and brings data together for improved field operations, customer service and analysis. PGE will deploy ESRI ArcGIS[8] in the first quarter of 2015, which will provide users with a wide range of data that can be displayed visually across an integrated set of technology platforms. These data will be useful for integrated outage management, asset management and future distribution management systems. GIS is foundational for implementing an advanced control and monitoring network. Expected capital cost for the new GIS system is $20 million.

2.2.2 Infrastructure Enhancements

- **SCADA:** Completing SCADA deployment on substations increases visibility of the grid to T&D operations, reducing the need to rely on customer-sourced information. In the last 12 months we added SCADA to a new substation (Cornell), and to three existing substations (Ramapo, Wallace and Sheridan). PGE is also planning to add SCADA to reclosers, tie switches, strategically placed sensors and faulted circuit indicators that will increase the visibility of the grid to T&D operators.

- **Fault Detection:** A pilot is underway to install Faulted Circuit Indicators on five feeders and integrate the data via AMI-FlexNet infrastructure. PGE is continuing its work with its Smart Meter vendor to implement a fault detection device that will communicate through the AMI network to help pinpoint fault locations. We expect this functionality, which should yield a significant improvement in SAIDI statistics, to be available within the five-year planning period.[9]

- **Distribution Automation:** (DA) will provide the potential for self-correcting and self-sustaining distribution feeders or microgrids where distributed energy resources and/or energy storage exists. A DA pilot is underway at Gales Creek, where a centralized DA server

[8] ESRI ArcGIS is the brand name for the data display system being deployed.
[9] We are installing ~40 Navicomm Base stations and ~120 Faulted Circuit Indicators (FCIs) on five feeders starting with a proof of concept on the Middle Grove Cordon Feeder in July, and plan to install FCIs on the remaining four feeders (Elma-Hudson 13kv, Newberg-Chehalem 13kv, Abernethy-Oregon City 13kv, Brightwood-North Bank 13kv) by this September.

has been established. It has already resulted in operational savings and System Average Interruption Duration Index (SAIDI)[10] reductions for customers served by the Gales Creek system. Operation typically isolates the affected line segment and restores other customers within one minute. In the past, those customers were sometimes out for several hours. The DA System can be monitored and controlled via SCADA.

- **By enhancing communications infrastructure to substation field devices,** PGE will be able to remotely collect substation management data through a Smart Grid data path. On distribution feeders, these enhanced communications will enable an extensive control-and-monitoring network. A project is underway to put secure network access to intelligent devices at more than 40 substations, which will:
  - Provide remote management capability
  - Enable advanced asset management via a communication link
  - Meet North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) compliance requirements.

- As part of **enhanced T&D asset monitoring,** intelligent electronic devices will keep track of large capital assets, promoting a more reliable grid and increased asset utilization. PGE has added advanced transformer monitors/controls to monitor dissolved-gas on 28 of 41 critical transformers. We plan to install an additional three per year with a targeted completion date of 2018.

- PGE has completed the installation of **Travelling Wave Fault Location Protective Relays** on the 100-mile long Bethel-Round Butte 230kV line. These relays enable greater precision in pinpointing the location of transmission faults, greatly reducing the duration of transmission outages. Historically, the Bethel-Round Butte 230kV line has been PGE's least reliable 230kV circuit. Sustained outages to this circuit averaged three-four days for restoration due to difficulty in locating the faulted section. This new technology will enable PGE to accurately locate faulted sections without dispatching helicopter patrol, saving $24,000 per event).

- **SCADA and protective device upgrades** will increase our ability to operate an adaptive grid and optimize utilization of the T&D system by eliminating all electromechanical relays,[11] transducers and legacy SCADA remote terminal unit systems.[12] In 2013, PGE added new fault recorders to provide more accurate power quality and disturbance information. By adding intelligent SCADA-enabled controllers to deliver Conservation Voltage Reduction we can minimize losses in the distribution system.[13]

- To optimize the operation and reliability of the transmission system, PGE has developed a system model for an **EMS State Estimator**. This model enhances real-time situational

[10] SAIDI is the total time without power for the average customer per year, measured in minutes.
[11] This annual program to upgrade electromechanical protective relays on the transmission system with digital relays is on track for completion in the next 10 years.
[12] In 2013, PGE began replacing first generation substation automation systems with new Ethernet-based systems.
[13] The required sensors will also provide operators with increased visibility of the grid.

awareness by enabling PGE to make more informed decisions by forecasting the transmission system response to predefined scenarios.

- In 2014, PGE will develop a **Real-Time Contingency Analysis** platform to alert operators when the transmission system could approach an operating limit following an outage event. This system will help operators make proactive adjustments to the transmission system in order to maintain grid reliability.

- PGE is evaluating the deployment of **Synchrophasors** at critical transmission facilities to enhance situational awareness. Synchrophasors provide a tool for system operators and planners to measure the state of the electrical system. A synchrophasor system, when combined with wide deployment of phasor measurement units (PMUs), dedicated high-speed communications, analytics, and other advanced protection assessment and control applications, will improve PGE's real-time situational awareness and the accuracy of decision support tools currently available to PGE's transmission system operators. Synchrophasor measurements can also be used to improve network analysis for assessing system security, assess adequacy to withstand expected contingencies and perform event analyses.

- PGE recently built an analysis tool for single phase transformers that collects interval energy data from every meter on the transformer to determine the specific date/time of peak load on the transformer and whether that demand is overloading the transformer. For small transformers, the tool replaces the old method of applying a statistical load shape to monthly data to determine peak load. The new method gives a much more accurate indication and is now used as the basis of proactive transformer replacements. It will be at least a year before we know whether this tool reduces the number of transformers failures. The new GIS described in Section 2.2.1 will become the system of record for the meter-to-transformer relationship once it is installed.

At this time, the estimated costs associated with these programs over the next five years are approximately $8 million. As these projects develop, we will further refine their associated costs.

2.3 Future Initiatives

2.3.1 Systems Development

PGE is working with its Smart Meter vendor to implement a fault-detection device that will communicate through the AMI network to help pinpoint fault locations. We expect this functionality, which should yield a significant improvement in SAIDI statistics, to be available within a five-year time frame.

A **Distribution Management System (DMS)** is foundational to the T&D Transformation vision**.** DMS manages distribution field hardware using real-time telemetry and automated-switching operations. The combination of a DMS and automated-switching devices creates the potential for a self-configuring network.[14] The continuous feed of power-flow data allows a DMS to track dynamic loading (relative to maximum ratings) on all distribution assets to determine if alternative feeds are possible. Even without communication to automated switching devices in the field, this system can speed the determination of safe switch orders during an outage. In non-outage conditions, a DMS can identify feeders where phase imbalances exist and quantify the savings possible under various "what if" configuration changes, recommend seasonal switch changes to minimize energy loss and manage field hardware to enable Conservation Voltage Reduction benefits. PGE is considering adding a DMS in the 2018-2020 timeframe. A cost estimate is not included as the project costs are still being developed and are largely outside the planning horizon.

PGE plans to conduct a future pilot program on advanced data analytics via the **T&D Analytics** Project. This pilot project will utilize existing data streams, such as AMI data, to produce actionable information required to enhance multiple planning and operations activities on PGE's T&D system. Anticipated results include improved service restoration times, increased system modeling accuracy and capabilities, and enhanced asset replacement and maintenance strategies.

2.3.2 Electric Vehicles as a Grid Resource

With approximately 730 public EV charging stations in Oregon, PlugShare.com has reported that Oregon has the highest number of public stations per capita in the United States. PGE expects the number of EVs in our service area to grow from about 5,000 today to 34,000 by 2020. The growth of this technology will benefit from early demonstrations with EV and EV charging station manufacturers to establish communications protocol and demonstrate Smart Grid charging concepts.

Some of the smart grid charging concepts PGE hopes to demonstrate over the next several years are controlling the time of EV charging, controlling the rate of EV charging, and integrating renewable power into EV charging. Additionally, PGE hopes to explore demonstrations such as vehicle-to-home, second-life battery applications and single-phase quick charging supported by battery power.

PGE is conducting RD&D projects in 2014 to explore these concepts:

- **Timed Charging:** Timers in cars or charging stations will enable more off-peak charging.
- **Smart Charging:** Demand response technology will manage the charging process, signaling the cars or charging stations to adjust demand up and down in real-time to optimize resource and system utilization.

Contingent upon support from vehicle manufacturers, PGE is considering future RD&D projects to explore these concepts:

[14] Self-configuring networks will require a combination of intelligent learning control software, automated switching, real-time, two-way communications with field hardware, and advanced monitoring capability with line voltage, VAR and frequency reactive assets, including distribution, generation and load.

- **Vehicle to Home:** Evaluate the potential for EVs to provide back-up power to residential homes through outlets or a service-panel connection.
- **Vehicle to Grid (V2G):** Evaluate EVs as an alternative to supply-side resources for ancillary services and renewables integration in PGE's IRP.
- **Second-Life Battery for Home or Grid:** Depending on battery availability, a pilot may be developed to demonstrate the viability of home and business-based storage as a cost-effective alternative to building supply-side resources for balancing renewable generation or meeting peak demand.

3. Customer Engagement

Customer engagement includes customer information and demand-side management Smart Grid initiatives. To advance customer engagement in the Smart Grid, utility outreach and customer education will be required. As with any new, behind-the-scenes technology, a significant effort will have to be made to raise customer awareness and lay the groundwork for customer engagement. The PGE Smart Power^{SM} umbrella is being used to help educate customers and communicate the benefits of our Smart Grid-related products and services. A critical education goal is to demystify the new product and service offerings enabled by Smart Grid technologies and help our customers understand how each fits into Oregon's energy future. Though a comprehensive communications plan was used to roll out Smart Meters in 2008, awareness remains low and communications efforts will need to be intensified if the customer engagement with the Smart Grid is to be realized in a meaningful way.

In addition to education campaigns, PGE will continue leveraging and expanding our current Smart Meter enabled products to:

- Supply customers with useful information about their energy consumption to help them use electricity more efficiently,
- Offer pricing options that allow customers to realize the value of more efficient utility asset utilization via price and control signals,
- Partner with customers to reduce their usage during critical system peaks.

Customer research and industry best practices are the cornerstones of PGE's Smart Grid awareness, education and engagement efforts. Our Product Development team maintains an extensive peer and vendor network that helps PGE remain ahead of many other utilities on our Smart Grid efforts. In fact, PGE's Smart Grid initiative was recognized in JD Power's customer engagement case study in 2013. In the years to come, we will continue to analyze and segment customer data to match programs to customer needs and interests while fulfilling the terms of our AMI stipulation and ensuring careful consideration of impacts on low-income customers.[15]

[15] Example: PGE coordinated with Community Action Agencies (CAAs) to ensure that PGE low-income customers understood the rules around remote disconnect/reconnect before that functionality was rolled out, so that they could proactively seek the assistance they needed to pay their utility bills.

3.1 Work to Date

3.1.1. Energy Tracker SM

Providing customers timely information about their energy usage represents a major opportunity to enable behavioral changes that will save energy and reduce energy bills. Launched in December 2011, Energy Tracker SM provides residential and general business customers access to their smart-meter data through their accounts on PortlandGeneral.com. Energy Tracker provides:

- Daily and hourly energy use charts
- Export of energy usage data to Excel or via the Green Button for use with third-party applications
- Billing insights that compare one billing period to another
- Savings tips that allow customers to create a profile, set a savings goal and receive tailored recommendations
- Direct links to ETO incentives for energy efficiency measures

In 2013, we released:

- Bill-to-date information
- Forecasted bill for residential customers
- A weekly text message or email alert for usage-to-date and forecasted bill (residential only for forecast)
- A text or email alert if the forecasted bill exceeds the customer's budget target by mid-month. [16]

PGE is able to make strides toward its IRP goals by actively engaging customers in the wise and efficient use of energy. This information has empowered more than 120,000 customers to control their electricity bills by helping them understand when and how they are using electricity. Since the program launched in December 2013, Energy Tracker customers have reduced their annual energy consumption 3% faster (332 kWh) than non-Energy Tracker customers.[17] In addition to helping customers better understand how they are using their PGE service, Energy Tracker also connected over 2,200 customers to the ETO site for energy efficiency programs.

To help ensure that PGE's low-income customers are aware of the Energy Tracker tool, PGE has provided information and demonstrations to the Community Action Agencies (CAAs) that serve our customers at our semi-annual meetings. At the request of its staff members, one of the agencies incorporated Energy Tracker into a new program it offered during winter 2013/2014. In addition, we offered to demonstrate the tool during the CAAs' energy education workshops with clients, and to train the low-income weatherization auditors on the tool, so that they could walk

[16] PGE sees this functionality as having particular importance to low income and other cost-conscious customers. In order to promote awareness of the new alerts among our low-income customers, PGE informed the CAAs about them during our semi-annual meetings in May and November, 2013.

[17] Based on a pre/post comparison of matched test and control groups.

through the information with a customer during the course of the audit.

3.1.2. Pricing

PGE's pricing programs seek to provide customers another tool for controlling their electric bill. In these programs, the cost of energy varies over time -- costing more when demand is greater -- providing customers an incentive to shift their usage to lower-cost (ie, lower demand) hours. PGE has two established pricing programs available to customers, and 68 percent of customers are aware of their availability:

- **Commercial and Industrial Time-of-Day Pricing (TOD)** was expanded to include Schedule 83 customers in 2014. Now all customers with monthly demand in excess of 30 kW are on a time-varying pricing program.

- **Residential and Small Commercial Time-of-Use Pricing (TOU)** is a voluntary program available to customers with up to 30kW of demand. The program has approximately 3,000 customers enrolled. For the past decade, PGE has limited promotion of the program (except to owners of electric vehicles) at the direction of the Portfolio Oversight Committee for reasons of cost-effectiveness. However, as interest in the program has grown with the availability of interval data and administrative costs have been reduced with the deployment of Smart Meters, we are re-evaluating whether to promote the program.

- **Flex Price (Critical Peak Pricing)** was a two-year pilot project launched in November 2011 with 1,000 customers. The program used a dynamic pricing structure, based on TOU rates, to encourage peak-load reduction on a general basis, but especially during times of unusually high demand. This behavior was incentivized by calling a four-hour event, during which the customers' energy price was approximately four times higher than normal. Customers were informed of events via email and/or telephone.

  In general, each customer lowered their peak usage between 0.11 – 0.32 kW during events and there was a small TOU effect on usage. Customer satisfaction with the program was relatively low (65%) compared to other pricing programs (75 – 85%).

  PGE secured a third-party evaluator to assess the pilot results and customer satisfaction with the program's design and filed the final evaluation results with the commission in May 2014. PGE will make use of these findings in designing future pricing programs.

3.1.3. Demand Response

In the coming years, PGE plans to implement cost-effective demand response at levels sufficient to be considered a capacity resource in our IRP.

Firm Load Reduction for Commercial & Industrial Customers, launched in 2010 via Schedule 77, is offered to PGE's large non-residential customers who are able to commit to a load reduction of at least 200 kW of demand at a single point of delivery. After providing the customer the required notice, PGE can initiate a four-hour load reduction event. To date, four customers have participated in this program, and they have demonstrated that load reductions of 18.3 MWs can be achieved reliably. These reductions are considered a resource available to mitigate the forecasted capacity shortfall identified in our IRP.

A Residential Direct Load Control Pilot was conducted with 20 conventional water heaters as part of the Salem Smart Power Project (see Section 5). PGE tested a new control strategy where water heaters were dispatched using recommendations from a software-based feeder simulation that sought to improve dispatch economics and improve system reliability in real-time. The tests showed that residential demand response resources could be dispatched based on real-time grid and environmental conditions. This pilot concluded in fall 2013. [18]

The **Energy Partner**[SM] Automated Demand Response Pilot uses automated controls to enable participating customers to respond to event signals within as little as 10 minutes.[19] In May 2013, PGE signed a contract with EnerNOC to provide at least 25 MW of firm capacity from customers with 30kW of demand or higher by December 2016. PGE will then determine whether to transition from a pilot to an official program, at which point demand reductions will be treated as a firm capacity resource, helping meet the forecasted capacity shortfall identified in our IRP and also qualifying as non-spinning reserves. If expanded, the program would represent an expenditure of up to $30 million for a cost-effective alternative to a supply-side capacity resource. A comprehensive evaluation of the pilot will be available in early 2016.

3.2 Work in Progress

3.2.1 Smart Water Heaters

PGE plans to initiate a small pilot that uses a standard modular communication interface in a new type of "smart" water heater to demonstrate simple peak load management. The objective of this effort is to test a program offer for our 350,000 residential customers who have electric water heaters. For a program to be offered, manufacturers will need to adopt the modular communication interface.

One of the benefits of the modular interface on smart devices is that each utility can choose the communication method most suitable for its market/geography. For the pilot, PGE is exploring the use of a hybrid communication device that uses the broadcast capability of FM radio data system combined with wi-fi to return information from the smart device to PGE, a low-cost, low-latency and high reliability technique. Further, for customers concerned about the privacy of information derived from devices in their home, the broadcast feature allows participation without any concern of revealing customer information.

[18] PGE dispatched water heater controls with a radio signal triggered by a transactive control price signal from Salem Smart Power Project through a "machine learning" software simulation.

[19] Lighting and heating, ventilation and air conditioning systems are expected to be the primary sources of load reduction.

In the longer term, customers may choose to own a gateway from a company like Verizon, AT&T, Google, or Comcast to manage all devices in their home. In cases like this, PGE will likely send messages to the gateway via the Internet, or via the provider's web portal built for the purpose of utility price/control signals. As of 2014, there is no standard approach to digital communication for demand response.

3.3 Future Initiatives

During the next five years, PGE will continue our work towards a flexible platform for initiating products and services that leverage our previous investments in our Smart Meter infrastructure. The Customer Engagement Transformation (CET) project is a set of initiatives that includes replacing PGE's vintage Customer Information System (CIS) and Meter Data Management System (MDMS) with systems that can more easily and efficiently enable new distributed resources and the delivery of pricing and demand-side management programs to our customers.

PGE will also monitor and evaluate the following program areas and technologies to determine whether a pilot or full-scale deployment is warranted.

3.3.1. Dynamic Pricing

PGE will be taking a strategic look at which voluntary pricing options and models offer the most value to our customers (see Appendix E) and will identify the programs we intend to pursue in the 2016 update of this report. PGE is hoping to launch a project in 2015 that would test customer response to several different pricing programs to determine which we want to pursue on a program basis post-CET. Under consideration are options that combine pricing programs with smart appliances/thermostats and energy management systems to maximize customer benefits. If programs leverage enabling technologies, PGE will work with the ETO to capture synergies with their energy efficiency programs.

3.3.2. HVAC Demand Response

Customer-friendly, internet-connected, smart thermostats are now emerging and may prove viable when both demand response and energy efficiency savings are taken into account. PGE is currently considering a demand-response pilot via smart thermostats for 2015. Should PGE pursue an HVAC demand-response program, we will seek to engage with the ETO to ensure the EE benefits are incented and captured. Meanwhile, we are tracking several new smart thermostat demand-response programs currently being demonstrated in California and Texas.

3.3.3. Home Energy Monitors and In-Home Displays (IHD)

For the small portion of customers who want to regularly check how much energy their home is using, a home energy monitor or IHD may be a good option. However, according to PGE research, most customers quickly lose interest in these tools, relegating them to the kitchen drawer. One area where IHDs do seem to provide enhanced customer value is in prepaid metering. Aside from possible use as part of a prepaid metering pilot, PGE is unlikely to offer IHDs without a significant improvement in the engagement model used by these tools.

3.3.4. Prepaid Metering

With prepaid metering, customers can pay a set amount of money for their energy use up-front and have daily usage fees deducted from the credit balance. Participating customers are provided frequent communications, alerting them to their remaining balance and how many days of service remain before service will be disconnected until additional payment is made. For budget-conscious customers or customers who move regularly (e.g. student populations), this program can be a valuable tool for managing energy spending. In addition, it gives participants a strong incentive to pay attention to their energy use.

PGE is monitoring the activities of utilities that offer this program, including Salt River Project and Direct Energy, as well as those utilities piloting it, including Arizona Public Service and Puget Sound Energy. Implementation of a voluntary prepaid metering pilot would not be pursued until CIS and MDMS replacement is complete. Before implementing any such pilot, PGE would actively engage with CAAs and low-income advocates on pilot design.

3.3.5. Green Button 2.0

PGE is a participant in the Green Button initiative. Green Button 2.0 is an expansion of that program which would enable customers to automatically download and transfer their energy-use data on an ongoing basis to a third party. PGE will monitor this program and consider it when updating Energy Tracker (currently planned post-CET). Green Button usage trends will be taken into account in any decision to expand the availability of this program. Currently, fewer than 1% of customers who log on to Energy Tracker ‘press’ the Green Button.

4. Distributed & Renewable Resources

In many ways, PGE has led the industry in the integration of Distributed Generation (DG) into the electric grid. In 2000, we began creating a ‘virtual power plant’ through our Dispatchable Standby Generation (DSG) program that is both unique in the industry and a great example of providing grid support. PGE is continuing to identify and develop innovative DG opportunities, including a program that will enable residential and small business customers to buy ‘virtual’ shares of local utility-scale solar projects and another program for large customers to host PGE-owned solar on their rooftops.

One potential liability associated with DG is that the output can be intermittent and unpredictable, causing voltage swings on the distribution lines. With customer-owned solar photovoltaic (PV) systems rapidly proliferating in other parts of the nation, PGE must be prepared to address this challenge. PGE is experimenting with energy storage at its Salem Smart Power Project and enhanced inverter functionality at its Baldock Solar Station to manage the voltage within an allowed operating range through dynamic reactive power control. Another goal of this enhanced inverter functionality is to achieve voltage and frequency ride-through capability so that distributed PV generators contribute to grid stability during system disturbances instead of disconnecting and exacerbating the problem. We expect to be active in the development of standards and control systems that ensure that these installations become assets to the grid rather than liabilities.

Beyond the distributed resources mentioned above, there are nascent technologies, such as thermal and electric energy storage, that could significantly impact PGE's Smart Grid efforts. For example, if EV batteries are available on a large enough scale, they could be utilized as a distributed power resource. This section of the report will address the development of distributed resources; section 5 will address the control, management and interfaces required in the back office in order for system operators to effectively use these resources.

4.1 Work to Date

4.1.1 Dispatchable Standby Generation

In the DSG program, PGE works with large customers that own onsite back-up power generators to provide a reliable, firm capacity resource. PGE has 93 MW online and included in our non-spinning reserves. We expect to reach 120 MW of DSG within the next five years. Over the last 10 years, PGE has invested $27 million in DSG; we expect to invest an additional $12 million in the next 27 MW.

4.1.2 Solar Energy Grid Integration Systems (SEGIS)

Initiated in 2008, this project is a partnership between the U.S. Department of Energy (USDOE), Sandia National Laboratories, power-equipment manufacturers, electric utilities and universities.[20] The USDOE provided the bulk of the project funding.

The goal of SEGIS is to remove the barriers to large-scale general integration of PV and to enhance its value proposition by enabling it to act as much as possible as if it were equivalent to a conventional utility power plant. Advanced inverters and controllers hold the potential to make high penetration of PV desirable to interconnected utilities.

Major successes to date include the demonstration of synchrophasor-enabled anti-islanding, VAR control, ramp-rate control, power-factor control, and low-voltage ride through, and power management functions, all of which will enhance the value of solar to PGE's system in the future.

4.2 Work in Progress

4.2.1 SunShot Initiative

PGE is on one of eight teams selected under the USDOE's SunShot Initiative for a SEGIS-Advanced Concepts grant in 2011.[21] The project tasks utility and solar experts with exploring

[20] To date, the SEGIS program has been a 3-year program initiative that included conceptual design and market analysis (Stage 1), prototype development and testing (Stage 2), and movement towards actual commercialization (Stage 3).
[21] PGE is a sub-contractor to Advanced Energy of Bend, Oregon, as part of this award.

solar shaping, i.e., the firming and shaping of solar PV power.[22] Over a three-year period the team has been working at our Baldock Solar Station to develop, demonstrate and commercialize:

- Synchrophasor-based island detection to provide the additional system protection that higher levels of intermittent generation sources require
- The use of synchrophasors to protect and optimize feeders on the distribution network
- A storage pilot to map out and understand the economic cost/benefit of using storage to reduce the effects of cloud-induced transients, and determine the amount of storage required to make solar more compatible with conventional dispatchable resources

Effectively using renewable energy assets and the implementation of Phasor Measurement Units (PMUs) [23] on the electrical grid will enhance reliability and could help regulate the flow of power, making instant reactions possible.[24] From the utility perspective, the developed technologies allow for increased levels of solar PV across distribution feeders due to better voltage support through local reactive power control. Transmission capacity is also improved by sourcing and sinking VAR demand closer to the point of use, improving overall broad system efficiency through line loss reductions.

4.2.2 Home Battery Back-Up System- Phase 1

The basic concept is to develop a laboratory prototype of a battery/inverter system that provides power to the entire house when there is an outage, but otherwise acts as a utility resource to mitigate peak demand or store excess wind energy at night. The project will define equipment specifications as well as design the metering system and utility controls necessary for a successful system. PGE has funded research at Portland State University through June 2014 with the project expected to continue until June 2015.

4.3 Future Initiatives

4.3.1 Thermal Storage with Water Heaters

With additional research, development and demonstration work over the next five-plus years, PGE hopes to demonstrate that aggregated water heater control can fill a need in our IRP that currently only power plants can meet. This would allow smart water heaters to provide load and generation following to system operators.

4.3.2 Bulk Thermal Storage

PGE is submitting a research proposal to a major university to explore the energy efficiency gains of a purpose-built thermal storage unit installed in a residential premise. The research proposal would leverage a home's space and water heat pumps by drawing on a thermal

[22] Demonstrations of the solar shaping initiative are expected in 2015, pending contract negotiations.
[23] PMUs are devices that produce precise time-stamped phasor measurements of current and voltage at a rate of 30 to 60 samples per second (far exceeding the rate of modern SCADA systems).
[24] PGE has completed the installation of five PMUs between its Canby substation and the Baldock Solar Station. These will be used in combination with a 300 kWh/300kW Li+ battery energy system installation at Baldock in 2014/15 pending funding approval from both the USDOE and PGE's capital review process.

reservoir to meet the customer demand. The utility would control when the thermal reservoir is cooled or heated in order to mitigate peak demand from these loads and aid with renewable integration (e.g. if a wind resource ends before expected, thermal reservoir charging can be curtailed; if the wind arrives early the thermal charge rate can be increased). Work on this proposal is expected to start late in 2014 and continue through May 2015.

4.3.3 Home Battery Back-Up System- Phase 2

If the lab research in 4.2.2 proves successful, and if battery costs continue to drop, then a field demonstration in a residential home or small business would be completed in the 2015/2016 time frame. The long-term goal would be to create a program where customers would install PGE-owned and maintained 50 kWh/6 kW battery inverter systems at their premises. These systems would serve as a capacity resource to leverage as additional renewables are integrated into the grid.

5. Salem Smart Power Project (SSPP)

The SSPP demonstration project was co-funded by the USDOE under the American Recovery and Reinvestment Act (ARRA) as part of the Pacific Northwest Smart Grid Demonstration. PGE served as a sub-contractor on the project to Battelle. This project provides a substantial educational opportunity for the energy industry and the general public on Smart Grid technologies. The project was formally initiated in 2010 and will conclude at the end of the year.

Key features of the Salem Smart Power Project include:

- **Storage:** An advanced lithium ion battery system (1.25MWh, 5 MW) provides uninterrupted power for testing microgrid concepts, real and reactive power regulation for voltage regulation and stability, as well as power cost hedging and ancillary services.
- **High Reliability/Microgrid**: A feeder segment can be automatically isolated from the grid with loads that can then be served with local DSG and the battery. In this condition, as long as there is fuel to power the six DSG generators, a microgrid is formed that can be operated independently of the PGE regional grid.
- **Self-Correcting Feeder**: PGE is testing and demonstrating various concepts related to increased reliability utilizing the Salem Smart Power Center. For example, distributed automation schemes using pole top switches automatically locate and isolate faulted portions of the feeder. The battery system can maintain voltage on the unfaulted portion while the DSG generators are started and brought on line. These high reliability concepts can improve overall system efficiency and reduce the frequency and duration of customer outages.
- **Demand Response**: As mentioned in section 3.1.3, 20 residential water heaters (ended in December 2013), and 51 commercial customers (continues through December 2014) agreed to participate in programs to lower their power use for set periods of time to help demonstrate integration of DR with the battery as part of grid support.
- **Transforming Renewable Energy Assets into Dispatchable Energy Solutions**: Using the Salem Smart Power Center, PGE is working with Kettle Brand to develop new energy storage controls for more efficient integration of solar and wind resources.

- **Transactional Control**: A fully automated control system provided real-time solutions for regional power issues such as low/high wind, high/low prices for transmission-supplied power to regional distribution resources and regional congestion management, enabling power generation to be regionally coordinated with energy prices

At the end of the demonstration, portions of the project will continue to operate as part of PGE's T&D system. Routine usage over time should allow continued assessment of its value to system reliability and renewables integration.

6. Research Development & Demonstration Efforts

Research and development necessarily implies a certain amount of fluidity in targeted research topics. Listed below are the Smart Grid-related Research, Development & Demonstration (RD&D) project ideas that are currently in the queue for 2014 funding. In some cases the projects are the same as those proposed in 2013, or closely related while others are new. These adjustments should come as no surprise inasmuch as smart grid projects tend to be cutting edge in concept and practice and thus subject to timeliness as well as constant objective and technical review. There are currently nine projects totaling $469,000 scheduled for funding in 2014 (see Appendix B for project descriptions).

- Wind Energy Integration & Storage Research*
- Feeder Optimization Simulations
- X-Phase: T&D High Observability, Advanced Situational Awareness System
- Rural Feeder Load Shaping with Kettle Foods PV System
- EPRI Collaborative Demo of DR-Ready Appliances
- Load Control EVSE Demonstration
- Single Phase DC Quick Charging Station Demonstration
- Oxford Substation – Rural Feeder Distribution Automation
- Thermal Storage as Resource in Residential Homes

*Newly proposed for 2014

7. General Business

7.1 Physical Security

There is nothing "smart" about a grid if the poles and wires and/or other equipment are down. For this reason, PGE continually looks beyond automation for cost-effective ways to improve grid resilience and reliability. A prime example is PGE's vegetation-management program, which has given PGE one of the lowest tree-related outage rates in the industry; this is remarkable given the high density of trees in the Pacific Northwest. All transmission and distribution facilities (substations and lines) are inspected by a PGE forester for vegetation clearances and tree-failure potential once every two years along urban feeders and once every three years in rural areas. [25]

During routine tree-trimming maintenance, foresters identify stretches of circuits that are particularly exposed to Douglas fir limb breakage during high winds. This information is turned over to Engineering for consideration of design alternatives like covered wire or selective undergrounding. For example, critical stretches of the Gales Creek feeder were reconductored with tree wire prior to the implementation of Distribution Automation.

7.2 Information Technology

7.2.1 Cyber Security

While the Smart Grid is designed to be more reliable, safer and more secure than the traditional grid, the systems developed to monitor and automate grid operations could potentially be compromised by cyber attacks, which could undermine reliability. PGE has been actively revamping internal networks to provide "secure-by-default infrastructure zones," which are positioned to support sensitive command-and-control systems, such as AMI, SCADA and DSG, in a consistent, unified, predictable, repeatable and automated fashion. These zones are implemented in the way Smart Grid interoperability demand, with a consistent architecture, technology footprint and a management toolset that PGE can use to quickly and repeatedly respond to new vulnerabilities or threats. Since Smart Grid relies on the unified integration of many disparate systems operating in unison, this consistent approach to infrastructure, architecture and security is critical to the interoperability and flexibility necessary to adapt to changing uses of a Smart Grid.

During the next five years, PGE will continue pursuing the following cyber security initiatives:

- Implement AMI upgrades in support of advanced encryption management tools brought about from Sensus' partnership with IBM
- Reposition command-and-control systems in secure-by-default infrastructure zones
- Extend virtualization and virtualization security benefits to command-and-control systems
- Improve posture-assessment capability for remote access
- Implement CIP compliance for network systems and substation remote access
- Mitigate the impact of new NERC requirements (for example, CIPv5) to utility systems
- Implement technology to provide trusted computing environments within hardware systems

[25] PGE spends $14 million annually on Vegetation Management.

7.2.2 Data Privacy

The Smart Grid encourages expanded use of data, which will require deeper coordination with customers in order to consider their individual privacy concerns. PGE's IT policy requires every system to classify the data within and to adhere to consistent handling requirements for that data. For example, data classified as confidential must be encrypted and follow proper destruction procedures when no longer needed. [26]

PGE is always considering projects that will allow customers more detailed access and control over their billing, usage or other data. This will make it easier for customers to enable posting of their individual data to mobile apps and websites. Any time activities such as these are pursued, data-privacy issues related to customer data will be addressed.

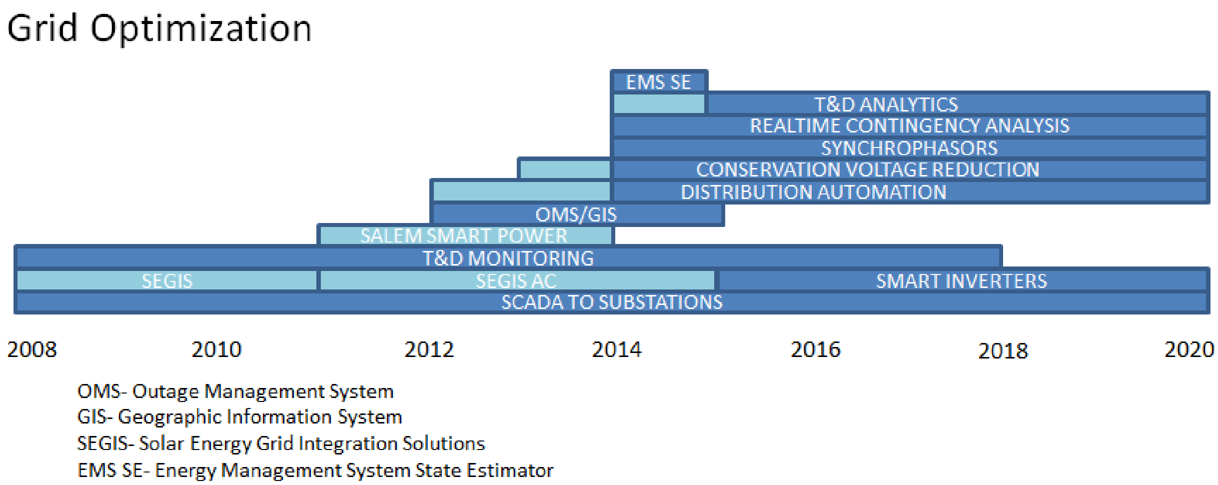
Finally, as part of PGE's ongoing Information Security Program, all future Smart Grid initiatives involving technology or customer information will require rigorous security testing and validation to ensure these projects are ready to deploy in a safe and secure manner.

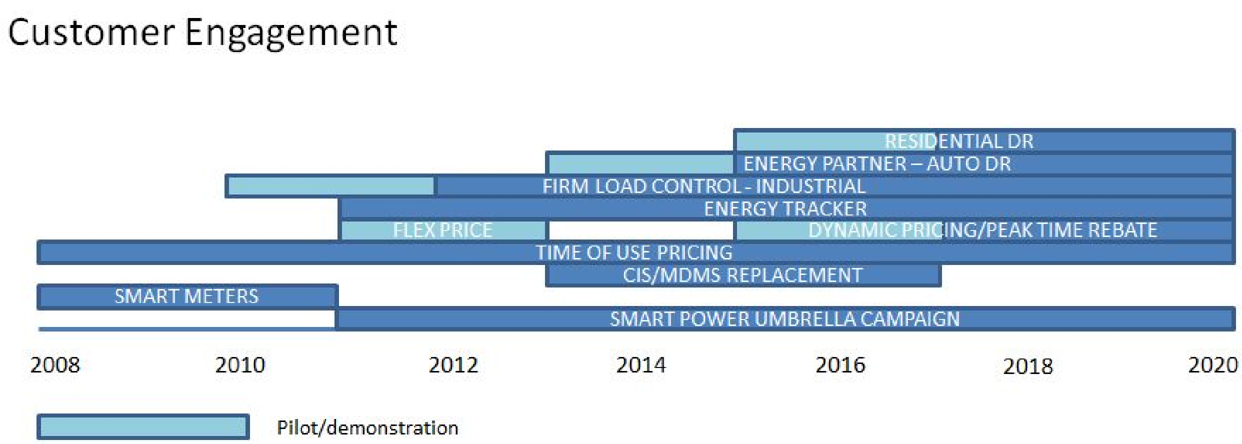
7.3 Future Initiatives

As PGE implements its new enterprise system platforms and plans for future Smart Grid applications, we will research and evaluate solutions that simplify system integration and reduce latency for time-sensitive solutions. Data warehouses and cloud computing might be recommended if they are cost-effective.

[26] Confidential information includes social security number, driver's license number, credit card numbers or financial information.

8. Smart Grid Roadmap





PGE is committed to continued leadership in delivering Smart Grid benefits to our customers — safer, more reliable and more efficient service along with new products and services that better meet their needs and expectations.

Appendix A: Leveraging AMI

Two-Way Communications Network

UE 189/Joint/Exhibit 200 cites testimony that the “system will be able to ‘talk’ with devices capable of hearing the signal so as to provide additional benefits related to directed and automated load control.” In reference to this testimony “CUB feels that one of the primary benefits of the smart grid is its potential ability to establish two-way communication between the utility and the residential customer.”

Two-way communication is an important aspect of the smart grid. PGE uses the AMI network to provide residential and business customers services like “real-time” alerts with Energy Tracker. The actual delivery is via email or text message, but these media are much less expensive than creating the same capability with the AMI system directly. PGE’s objective is to create benefits using the AMI system, but the way we communicate these benefits to residential customers will often be through media that do not include the AMI system, primarily for cost reasons. If sub-hour latency becomes an important requirement, for example to implement direct load control, then AMI may useful, but even then alternative communication media, may be more cost-effective.

PGE uses the two-way features of the AMI system each and every day, to read meters and communicate with distribution sensors. The system is also used to ‘ping’ meters to confirm outages. Sensus provides an optional, back-office, demand response application module. Sensus also has a product line of hardware that could be installed. The cost could only be justified under a major DR program. But more importantly, the cost of providing communications is not now, nor has it ever been, the barrier to launching DR at scale. For pilots it is much less expensive to use alternative communication methods, and there are many. When PGE has a program that can scale to approximately100,000 customers, it might be cost effective to use the AMI backbone in lieu of paying third parties a recurring cost for providing communication.

Summary of Potential Activities and Benefits Described in UE-189

In the OPUC AMI Review process (UE-189) PGE discussed twelve possible uses of the AMI system that might achieve additional benefits beyond those included in PGE’s economic model. The so-called “Customer and System Benefits” document included in Order 08-245 described these benefits in three categories. The rest of Appendix A maps those benefits into the current Smart Grid Report.

Category 1: Demand Response Related Activities and Benefits

Information-Driven Energy Savings: PGE has commercialized this capability for customers as Energy Tracker. Future activity is described in Section 3.3.2.

IRP Capacity Planning: PGE’s latest activities in this area are described in Sections 3.1.3, 3.2, 3.3.2.5, 4.3.1, and 4.3.2.

Critical Peak Pricing: PGE completed this pilot per Section 3.1.2; future activities are described in Section 3.2.2.2.

Appliance Market Transformation (DR-Ready Appliances): As discussed in Section 3.2.1 and Appendix B (EPRI Collaborative), PGE maintains a strong effort in this activity since market transformation is the key to wide-scale, cost-effective DR.

Category 2: Distribution Asset Utilization

Avoided Service Transformer Failures: Benefits for commercial transformers will require extensive development or a DMS system (see Section 2.2.2).

Proper Transformer Sizing: PGE uses AMI data in a limited, labor intensive way to prioritize transformer replacement. Optimization at scale will require a DMS (see Section 2.3.1).

Feeder Conductor Work: Pilot activity in this area is deferred until PGE completes the new GIS (see Section 2.2.1); however per Appendix C, PGE has hired an engineer to conduct the analytic work required to determine how to prioritize which feeders are worthy of re-conducting work. Optimization at scale will require a DMS (see Section 2.3.1).

Category 3: Outage Management

General Outage Management: This capability should exist when we complete the work-in-progress described in Section 2.2.1.

Avoided Trouble Calls: Smart meters are currently being 'pinged' routinely when customers report an isolated outage, avoiding trouble calls in situations where PGE service to the home has not been interrupted. Utilizing smart meters for faster one-premise outage response and improved storm management is planned and should be available once the new Outage Management System is in place (see Section 2.2.1).

Faster On-Premise Outage Response: This capability should exist when we complete the work-in-progress described in Section 2.2.1.

Improved Storm Management: This capability should exist when we complete the work-in-progress described in Section 2.2.1.

Faster Fault Location Identification: PGE has implemented pilots and/or system enhancements that deliver this benefit (see Sections 2.2.2 and 2.3.1).

Appendix B: Research, Development & Demonstration Projects

Project	Description	Projected Cost
Wind Energy Integration & Storage Research	Improve renewables integration through advanced coordination and control of energy storage. More effective coordination and control of energy storage systems can improve the predictability of variable renewables such as wind plant outputs, and decrease the cost of wind integration.	$20,000
Feeder Optimization Simulations	Complete reporting studies of two feeder optimization simulations PGE developed in collaboration with Intel Research and Development, Power Systems Group, the University of Colorado, Power Systems program, and the Portland State University Power Systems program. Outline benefits and differences between using neural network tools vs. linear programming tools for distribution microgrid feeder optimization. Tests are proposed to determine the effectiveness of each approach.	$12,000
X-Phase: T&D High Observability, Advanced Situational Awareness System	The X-Phase Project is the integration of synchrophasors (phasor measurement units) on PGE's T&D system. A synchrophasor system, with wide deployment of phasor measurement units, dedicated high-speed communications, analytics, and other advanced protection assessment and control applications will improve real-time situational awareness and decision support tools available to PGE transmission system operators.	$80,000
Rural Feeder Load Shaping with Kettle Foods PV System	Kettle Foods in Salem has given PGE access to its real-time solar output data. The existing control systems within the Salem Smart Power Center will utilize this data along with real-time load data from the Rural Feeder to demonstrate advanced concepts in solar power integration. This project will install an algorithm in the Salem Smart Power Center master controller and then test and tune those controls.	$32,000
EPRI Collaborative Demo of DR-Ready Appliances	EPRI has convened a group of leading utilities, appliance manufacturers and communication device makers to conduct field demonstrations in order to advance end-to-end capability of demand response using the CEA-2045 appliance socket communication interface. This is a three part project beginning in 2013 with the field demonstration starting between mid-2014 to early-2015.	$95,000

Project	Description	Projected Cost
	PGE intends to test demand response with hot water heaters and EVSEs.	
Load Control EVSE Demonstration	This project would team PGE staff with an Electric Vehicle charging station manufacturer and software tool provider to develop a prototype that can control residential charging load in real time. Two benefits would be explored: (1) the reduction of utility demand charges by controlling total EV charging load, and (2) the creation of a new demand response resource by controlling EV charging load.	$60,000
Single Phase DC Quick Charging Station Demonstration	This project would utilize battery storage to enable a DC Quick Charger to operate where only single-phase power is available. Currently, all DC Quick Charging equipment requires three-phase power. This would also explore better efficiency as the DC power to the charger would come from the battery storage directly and not be converted to AC then back to DC.	$25,000
Oxford Substation – Rural Feeder Distribution Automation	Four automatic Intellirupter switches have been installed on the Rural Feeder with funding from the Salem Smart Power Project. These switches will be used primarily in commissioning, testing and start-up of SSPP. This project proposes to utilize these switches at a higher level for distribution automation, namely fault location, isolation and service restoration.	$110,000
Thermal Storage as Resource in Residential Homes	Fund an engineering project at a major university to model a heat pump system where the heat pump draws on a thermal storage reservoir instead of outside air so that peak demand can be avoided. The anticipated project scope will include construction of an operational system, thermodynamic modeling and verification, and design of controls to optimize operation.	$35,000

Appendix C: Staffing & Resource Requirements

In Appendix D of our 2013 Smart Grid report, identified the need for 5 incremental positions. Those positions were funded in UE 262. Four positions have been filled in 2014; one will be filled in early 2015.

- Strategic Asset Management Smart Grid Engineer
- Customer and Smart Grid Data Analyst (currently being filled by an outside contractor until a full-time employee can be funded in 2015)
- Project Manager Emerging Technology & Distributed Generation (will lead the development and demonstration of emerging technologies in solar, battery, and other technologies related to smart grid value propositions)
- Project Manager Smart Grid Strategy and Projects (will take on the development, coordination, and reporting activities described in 2013)
- T&D Planning Smart Grid Engineer

PGE’s Transmission & Distribution Engineering groups identified additional needs and received approval to create two incremental positions in 2014 to focus on automation. These positions are critical to accelerating our SCADA work. One position adds an engineer that specializes in automation design for substation and feeder equipment, the second position adds a SCADA technician to help accelerate the implementation pace of the field work.

Management review of distribution positions since the 2013 report has also identified further need for engineers to research and design smart grid systems to enable distribution automation. Consequently, the 2015 budget includes (pending approval of PGE’s 2015 rate case) two new engineering positions to fulfill this work. The 2015 rate case testimony indicates a net reduction of 4 FTE for 2015; this reflects a reduction of 6 positions primarily driven by the T&D Transformation project described in Section 2.2.1 of the 2013 report, plus the addition of the two positions described above.

Appendix D: Conservation Voltage Reduction

Pilot Project: Initial Results

Introduction

Conservation Voltage Reduction (CVR) is a means of lowering customer power demands by operating distribution feeders within the lower portion of the acceptable voltage bandwidth.[27] The Northwest Energy Efficiency Alliance (NEEA) expects this to reduce the customers' energy consumption based on findings in their Utility Distribution Systems Efficiency Initiative.

In 2012, PGE conducted a study to determine the viability of implementing a CVR program without incurring power quality issues. Simulated results confirmed the conclusion made by NEEA that CVR implementation will reduce demand, and thus the customers' energy consumption.

The simulated results led to the funding and implementation of CVR at two substations within PGE's service territory. Implementation was completed in the winter of 2013. Initial pilot results have validated the conclusions from the simulation.

Results

Simulated Results

Software was used to analyze possible demand reduction by simulating CVR as a peak shaving method. The studies were performed under four load conditions: heavy winter, heavy summer, light winter, and light summer. Heavy loading conditions represented PGE's forecasted 2013 1-in-3 seasonal peak loads. Light loading conditions represented the forecasted average daily peak demand for each season.

We were able to evaluate discrete moments in time, limiting this study to CVR as utilized for peak shaving.

[27] ANSI Standard C84.1-1989 establishes a "Range A" operating secondary voltage of +/-5% of the voltage base.

Table 1 shows the voltage sensitive load model used for the simulated CVR study, broken down by customer type.

Table 1. Voltage Sensitive Load Model for simulated CVR study.

	Voltage Sensitive Load Model Constant Power (%) /Constant Impedance (%)			
Customer Type	*HS*[1]	*LS*[2]	*HW*[3]	*LW*[4]
Residential ("Winter Peaking")	60/40	50/50	30/70	40/60
Residential ("Summer Peaking")	70/30	60/40	40/60	50/50
Commercial / Residential ("Non-peaking")	60/40	50/50	40/60	50/50
Industrial	80/20			

[1]HS corresponds to a 1-in-3 summer peak loading condition
2LS corresponds to an average summer loading condition, at peak
3HW corresponds to a 1-in-3 winter peak loading condition
4LW corresponds to an average winter loading condition, at peak

A voltage sensitive load model was used for all customer loads. This model represents each customer as a ratio of constant power and constant impedance loads. The ratio of the load types is determined by load condition, station type (i.e., winter or summer peaking), and customer type (i.e., residential, commercial, or industrial). A transformer is given a "Winter Peaking" designation when the average quotient (i.e., winter divided by summer) of the normalized 1-in-3 loads over the last five years is greater than 1.10. A transformer is "Summer Peaking" when the inverse quotient is greater than 1.10. For this study, the Hogan South site WR4 transformer was classified as "Winter Peaking."

The study base case utilized feeder models that were balanced and included the addition of strategically placed fixed capacitor banks. This initial modeling was performed to ensure that recorded benefits were results of the implementation of CVR and not of customary feeder improvements. Fixed capacitor bank placement was determined via simulation of the light winter loading condition, as this is the condition with the lowest VAR flow.

Table 2 shows the results of simulated CVR implementation at the Hogan South WR4 transformer.

Table 2. Simulated CVR results at Hogan South WR4.

	Simulated Hogan South WR4	
Season	*% MVA : 1% V*[1]	*Total % MVA*[2]
Winter	1.33 : 1	3.56%
Summer	0.78 : 1	1.06%

[1]Corresponds to simulated percentage of peak load reduction per one percent voltage reduction
[2] Corresponds to simulated total percentage of available peak load reduction

CYME studies indicate that the implementation of CVR as a peak shaving method is most advantageous during winter peak loading, and least beneficial during summer peak loading. These results were expected, because resistive loads (e.g., electric furnaces) are more prevalent during the winter months, and constant power loads (e.g., air conditioners) are utilized more often during summer months.

Pilot Results

The physical implementation of CVR was completed on the Hogan South WR4 transformer in July 2013. CVR implementation included the following operational functions:

- Day-on Day-off operation to provide a data comparison between "normal" mode and "CVR" mode.
- Auto/Manual control for use during contingencies and peak shaving.
- Hourly voltage data monitoring at targeted residential customer meters to ensure acceptable voltage levels.

A four-year analysis of energy consumption data at five feeders was performed to determine if a summation of Day-on-Day-off energy consumption data resulted in similar total annual consumption. While no two days have identical loading patterns, it was determined that analyzing the effectiveness of CVR using Day-on-Day-off operation resulted in an acceptable variance percentage; the largest annual variance calculated over the four-year period was ±0.51%.

Table 3 shows the results of physical CVR implementation at the Hogan South WR4 transformer.

Table 3. Pilot project CVR results at Hogan South WR4.

	Pilot Hogan South WR4	
Season	*% kWh : 1% V* [1]	*Total % kWh* [2]
Winter	1.22 : 1	3.04%
Summer	0.76 : 1	1.14%

[1] Corresponds to percentage of killowatt-hour reduction per one percent voltage reduction

[2] Corresponds to total percentage of killowatt-hour reduction

Measured quantities confirm that energy consumption at the Hogan South WR4 transformer was reduced as a direct result of CVR implementation. CVR is more beneficial in the winter due to the increase in resistive loads (e.g., electric furnaces) when compared to summer load composition. Days in which load was transferred to, or from, a feeder associated with the Hogan South WR4 transformer were not included in the analysis. Also, the following day was excluded. In total, 96 "summer days" were included in the analysis; 28 "winter days" were included.

Table 4 shows the cost-benefit of physical CVR implementation at the Hogan South WR4 transformer.

Table 4. Pilot project CVR energy consumption and cost saving at Hogan South WR4.

	Pilot Hogan South WR4				
Season	*Actual kWh Reduction*	*Potential kWh Reduction*	*Projected Customer Savings [1]*	*Estimated Savings/Customer [2]*	*Estimated Savings/Customer/Day*
Winter (28 days)	24,843	49,686	$5,267	$0.68	$0.02
Summer (96 days)	43,425	86,850	$9,206	$1.19	$0.01

[1]Based on 1000 kWh/month residential customer average $/kWh ($0.106)

[2] Based on 7709 customers

The daily potential cost savings for the average residential customer (i.e., one who consumes 1000 kWh per month) as a result of CVR implementation is $0.02 in the winter and $0.01 in the summer. This corresponds to an estimated annual savings of $6.62 for the average residential customer.

A review of voltage data at the 29 monitored customer meters show operating voltages are consistently within the acceptable voltage bandwidth.

Due to the small sample size (14 days), CVR data at Denny substation was not included in the analysis of pilot project results.

Simulated Results vs. Pilot Project Results

Completing CVR studies using a simulated CVR implementation and a physical pilot project help to answer the two following questions:

1. Is CYMDIST an adequate tool for estimating the effectiveness of CVR implementation?
2. Is CVR implementation a cost-effective method to reduce energy consumption?

Table 5 compares the simulated CVR implementation results, physical CVR implementation results, and expected physical CVR implementation results.

Table 5. Simulated results vs. Actual pilot project results vs. Expected pilot project results.

	Simulated Hogan South WR4		Pilot Hogan South WR4		Expected Pilot Result Ranges
Season	*% MVA : 1% V [1]*	*Total % MVA [2]*	*% kWh : 1% V [3]*	*Total % kWh [4]*	*Total % kWh [4]*
Winter	1.33 : 1	3.56%	1.22 : 1	3.04%	2.16% - 3.18%
Summer	0.78 : 1	1.06%	0.76 : 1	1.14%	0.29% - 1.30%

[1]Corresponds to simulated percentage of peak load reduction per one percent voltage reduction

[2] Corresponds to simulated total percentage of peak load reduction

[3] Corresponds to percentage of killowatt-hour reduction per one percent voltage reduction

[4] Corresponds to total percentage of killowatt-hour reduction

With the data available today, CYMDIST can be classified as an adequate tool for estimating the effectiveness of CVR implementation. Studies performed by H. Lee Willis, author of the *Power Distribution Planning Reference Book,* led to his conclusion that utilities should expect to see at least a 25% reduction in “CVR effectiveness” when comparing MVA reduction (i.e., peak shaving) to kWh reduction (i.e., constant implementation). When accounting for the ±0.51% variance and the conclusion made by Mr. Willis, the seasonal expected pilot project result ranges encompass the simulated results, as shown in table 5.

Determining whether CVR is a cost-effective method to reduce energy consumption depends on the definition of “cost-effective.” The total cost to implement CVR at Hogan South substation is $70,816. The projected annual savings for all customers served by the Hogan South WR4 transformer is $30,811. At the conclusion of the pilot project, a PGE financial analyst will make the determination as to whether or not CVR is a cost-effective method to reduce energy consumption.

Conclusion

The implementation of CVR resulted in reduced customer demand and energy consumption. Whether constantly implemented, or used as a peak shaving method, CVR is more beneficial in the winter due to the increase in resistive loads (e.g., electric furnaces) when compared with summer load composition; however, benefits are realized year-round. As a result of reduced energy consumption, customers served by a transformer with active CVR will likely realize a slight reduction in their total bill, while continuing to receive voltage at the meter base consistently within the acceptable voltage bandwidth.

Results from the simulated CVR implementation and the physical pilot project led to the determination that CYMDIST is an adequate tool for estimating the effectiveness of CVR implementation.

Appendix E: Dynamic Pricing

PGE is taking a strategic look at which voluntary pricing options and models offer the most value to our customers. Programs being examined range from the day ahead pricing to opt-out Peak Time Rebates (PTR). The following is a short list of programs that are being reviewed:

Company	Program	Summary of Affects
Oklahoma Gas and Electric	• Opt-In • Day ahead Time-of-Use (TOU) pricing with Critical Peak Pricing (CPP) for events (pricing changes daily) • Peak Time Rebates (PTR) • 80K Customers	• High customer satisfaction particularly with Low Income • Low Income customer saved significantly • Significant load trimming
Entergy New Orleans	• Pilot of PTR • In home device to monitor energy, Web, and direct load control	• High Customer Satisfaction particularly with Low Income • Significant load trimming
Baltimore Gas & Electric	• Opt-out PTR program. Customers receive $1.25 per KWh saved during an event. • 300K Customers	• High customer satisfaction • Significant load savings • Cost effective requires assuming wholesale market adjustment
Connecticut Light & Power	• Pilot of TOU and CPP	• High customer satisfaction • Load savings in-line with PGE CPP pilot
Boulder Muni	• Pilot of TOU and CPP	• High customer satisfaction • Load savings in-line with PGE CPP pilot

Additional programs from Sacramento Municipal Utility District, San Diego Gas & Electric, Southern California Edison, and Pacific Gas & Electric are also being evaluated.

PGE's goal is to adopt the best aspects of these programs that fit with Oregon's climate and culture. PGE is working to design a project for 2015. The project would test customer response to several different pricing programs and determine which we want to pursue on a program basis post-Customer Engagement Transformation. An initial list of candidates appears on p.37.

	Educated Basic Rate	**Peak Only**	**Traditional Peak**	**Day, Night Critical Peak**
Description	• Customer will have basic rate. However, they will have been educated as to the importance of peak avoidance.	• Customers will have a peak rate and off peak rate. They will be subjected to a Critical Peak rate when events are called. • The peak will be consistent over the year.	• Customer will have a traditional peak pricing program: Peak, Mid-Peak, OffPeak. • The peak timing will stay consistent during the year	• Customer will have two daily rates: Day and Night. The customers will be subject to a Peak rate when events are called. • Hours will be different than Peak only
Have PTR	50%	50%	50%	50%
No PTR	50%	50%	50%	50%