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May 28, 2015

Via Email
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OPUC Filing Center
3930 Fairview Industrial Dr., SE
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RE: **2015 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 2015 Smart Grid Report, PGE held a Smart Grid workshop on April 15, 2015 to receive and consider feedback from stakeholders. Pursuant to Order No. 12-158, PGE provides the attached 2015 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 294 Service List
LC 56 Service List

2015 Smart Grid Report

June 1, 2015



Portland General Electric

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Acronyms

ADR ....Automated Demand Response
AMI...Advanced Metering Infrastructure
AC ....Alternating Current
AGC ....Automated Generation Control
AMI...Advanced Metering Infrastructure
ANSI ....American National Standards Institute
ARRA ....American Reinvestment and Recovery Act
BIS ....Battery Inverter System
BPA...Bonneville Power Administration
CAA ....Community Action Agencies
CCS ....Command-and-Control Systems
CELID.....................................Customers experiencing long interruption durations
CEMI.......................................Customers experiencing multiple interruptions
CIP ....Critical Infrastructure Protection
CIS ....Customer Information System
CPP ....Critical Peak Pricing
CVR ....Conservation Voltage Reduction
DA...Distribution Automation
DC ....Direct Current
DGA..Dissolved Gas Analyzer
DER...Distributed Energy Resources
DLC...Direct Load Control
DMS..Distribution Management System
DR ....Demand Response
DSG...Dispatchable Standby Generation
DTS ....Distribution Temperature Sensing
EMS ....Energy Management System
EPRI..Electric Power Research Institute
EV ....Electric Vehicle
FC..Fuel Cell
FCI ....Faulted Control Indicator
GIS ....Geographical Information Systems
HRZ...High Reliability Zone
ICT ....Information & Communication Technology
IED..Intelligent Electronic Device
IHD ....In-Home Display
IRP ....Integrated Resource Plan
kW...Kilowatt
kWh...Kilowatt-hour

MDC ....Meter Data Consolidator
MDMS ....Meter Data Management System
MW ....Megawatt
MWa ....Average Megawatt (8,760 mega-watt hours)
MWh ....Megawatt-hour
NEEA.......................................Northwest Energy Efficiency Alliance
NERC.......................................North American Electricity Reliability Commission
NIST...National Institute of Standards and Technology
OMS...Outage Management System
O&M..Operations and Maintenance
OPUC.......................................Oregon Public Utilities Commission
PCC..Portland Community College
PDC..Phasor Data Concentrator
PGE..Portland General Electric
PMU...Phasor Measurement Unit
PNNL ....Pacific Northwest National Lab
PV ....Photovoltaic
PSU ....Portland State University
RAS..Remedial Action Schemes
RD&D......................................Research, Development and Deployment
RTCA.......................................Real-Time Contingency Analysis
RTU..Remote Terminal Unit
SAM...Strategic Asset Management
SCADA....................................Supervisory Control and Data Acquisition
SE...State Estimator
SEI...Software Engineering Institute (of Carnegie Mellon)
SEGIS ....Solar Energy Grid Integration Systems
SGMM ....Smart Grid Maturity Model
SPS...Special Protection Scheme
SSPC ....Salem Smart Power Center
SSPP...Salem Smart Power Project
T&D ....Transmission & Distribution
TIS..Transactive Incentive Signal
TOD ....Time-of-Day
TOU ....Time-of-Use
USDOE ....United States Department of Energy
VAR ....Volt Ampere Reactive
WECC......................................Western Electricity Coordinating Council
WISP ....Western Interconnection Synchrophasor Program
WTC...World Trade Center (Portland, OR)

Section 1. Executive Summary

Background

This report represents PGE's third Smart Grid Annual Report filing in compliance with OPUC Order No. 12-158 in Docket No. UM 1460. This report includes an update on PGE's smart grid initiatives including updates on each of the eight conditions outlined by the OPUC in response to the previous report filing. In preparation for filing, PGE provided external stakeholders opportunities to provide feedback on this report.

Strategy

PGE has made considerable investments in smart grid initiatives, staff, and research. As smart grid is becoming an increasingly integrated part of PGE's business, PGE has recognized the necessity to develop a more integrated corporate-level strategy and vision of its future state to maximize the benefits of smart grid investments. As a result, PGE has recently established a smart grid task force of subject matter experts with the objectives to:

- Evaluate industry best practices in smart grid deployment
- Establish a target smart grid future state
- Update PGE's smart grid vision and road map

The initiative will evaluate all aspects of PGE to determine how to best prepare the Company for future smart grid success. PGE anticipates presenting the outcome of this effort to external stakeholders for feedback in the latter half of 2015. This major update is expected to be reflected in the 2016 annual report.

Smart Grid Initiatives

PGE has completed, is deploying, or is considering more than 50 smart grid initiatives across the Company, spanning grid optimization, customer engagement, and distributed & renewable resources. These three categories have historically been reported separately, but as many distributed & renewable resource projects progress, they are evolving into grid optimization projects. Consequentially, grid optimization and distributed & renewable resource projects have been grouped in this report.

- **Grid optimization:** transmission, substation, and distribution systems investments in hardware, software, technologies, and processes that improve system reliability and efficiency, increase flexibility of grid integration, enhance the ability to reduce peak demand, and reduce overall utility operation costs.

PGE Grid Optimization Initiatives:

- Advanced Metering Infrastructure
- Energy Management System & Automated Generation Control
- Overloaded Transformer Analysis
- SCADA (Supervisory Control and Data Acquisition)
- Conservation Voltage Reduction
- Salem Smart Power Project
- Solar Grid Integration Systems
- Dispatchable Standby Generation
- Remote Service Detection
- Substation Automation
- Substation Remote Access Server
- Communications Upgrades
- T&D Asset Monitoring
- T&D Analytics
- Distribution Automation
- Fault Detection (Distribution)
- Voltage Disturbance Detection
- State Estimator
- Real-time Contingency Analysis
- Synchrophasor Deployment
- Travelling Wave Fault Location Protective Relays
- Remedial Action Schemes
- Distribution Temperature Sensing
- Outage Management System
- Geographical Information System
- Microgrids
- Home Battery Back-up

- **Customer engagement:** investments in energy information systems, pricing programs, demand response, and system development that improve the customer experience, save energy, and reduce peak demand.

PGE Customer Engagement Initiatives:

- Energy Information Systems:
  - Energy Tracker
  - Energy Expert
- Pricing Programs:
  - Time of Day Pricing
  - Time of Use Pricing
  - Flex Price/Critical Peak Pricing
  - Pilot Development Research & Peak Time Rebates
- Demand Response
  - Firm Load Reduction
  - Energy Partner
  - Residential Direct Load Control (non-thermostat)
  - Smart Thermostat DR
- Customer Information System
- Meter Data Management System

Related Activities

In addition to PGE's smart grid initiatives, PGE maintains strong business practices that support PGE's efforts in Smart Grid development. PGE's Strategic Asset Management program helps prioritize how the Company deploys smart grid initiatives. The Company's efforts in physical security, such as vegetation and critter management, help ensure smart grid investments realize their full value. Additionally, PGE's cybersecurity and data privacy policies and process position PGE to minimize risk of cyberattack or loss of critical data. PGE's commitment to low-income customer engagement ensures programs are designed and targeted to reach all customers.

Section 2. Background

A. Smart Grid Report History & Purpose

In 2012, the OPUC issued Order No. 12-158 in Docket No. UM 1460 to establish the Commission's smart grid policy goals and objectives, utility reporting requirements, and guidelines for utility actions related to smart grid:

OPUC's Policy Goals and Objectives:

The Commission's goal is to benefit ratepayers of Oregon investor-owned utilities by fostering utility investments in real-time sensing, communication, control, and other smart -grid measures that are cost-effective to consumers and that achieve some of the following:

- *Enhance the reliability, safety, security, quality, and efficiency of the transmission and distribution network*
- *Enhance the ability to save energy and reduce peak demand*
- *Enhance customer service and lower cost of utility operation*
- *Enhance the ability to develop renewable resources and distributed generation*

Required Elements of Annual Reports

- *Smart Grid Strategy*
- *Status of Smart Grid Investments*
- *Smart Grid Opportunities and Constraints*
- *Targeted Evaluations*
- *Related Activities*

This report represents PGE's third report in response to Order No. 12-158. A history of filing activity is listed below:

Table 1 – History of PGE Smart Grid Annual Report

Date	Order No.	Event Detail
05/08/2012	12-158	OPUC Outlines smart grid goals & reporting requirements
06/01/2013	NA	2013 Smart Grid Annual Report Filed
08/28/2013	13-311	Acceptance of 2013 Smart Grid Annual Report
06/01/2014	NA	2014 Smart Grid Annual Report Filed
10/01/2014	14-333	Acceptance of 2014 Smart Grid Annual Report

B. Targeted Recommendations

In response to PGE's 2014 report, the OPUC made several targeted recommendations in Order No. 14-333, which are summarized in Table 2. Each recommendation is addressed in this report on the page listed.

Table 2 – Summary of Recommendations from Order No. 14-333

Category	Recommendation	Page(s)
Conservation Voltage Reduction	Report on the findings of the CVR pilot program and the Company's next steps for expansion of the CVR Program.	60
Critical Peak Pricing	Provide an evaluation of the company's CPP Program, any recommended changes to the Program, and next steps for the Program.	68
Smart Grid Metrics	Conduct workshops to explore how to best measure & track benefits of Smart Grid investments.	47
Synchrophasors	PGE should report to the Commission on the company's evaluation of deployment of more synchrophasors in its system.	75
Smart HVAC & Thermostats	PGE should provide information on PGE's Smart HVAC & Smart Thermostats pilot, including what will be tested and how success will be measured.	91
Salem Smart Power Project	Share lessons learned from the project and how results will be documented, shared, built upon going forward, and evaluated for cost effectiveness.	80
Smart Inverters	Document the use of smart inverters in PGE's service area and report on future initiatives.	89
Time of Use Pricing	PGE should report on its evaluation of whether to actively promote voluntary residential and small commercial time of use pricing programs.	91

C. Stakeholder Engagement

In preparation for filing this report, PGE provided key external stakeholders opportunities to contribute input and feedback on this smart grid report.

Per suggestions made at the time of the original report filing, PGE offered key stakeholders opportunity to review a draft and provide feedback six weeks prior to report delivery:

Table 3 – Stakeholder Engagement

Date	Milestone
12/18/2014	Smart grid metrics workshop with key stakeholders
01/14/2015	CPP Update and Pricing/Residential DLC public meeting
02/25/2015	Smart grid metrics workshop with key stakeholders
03/04/2015	Pricing & Residential DLC workshop with key stakeholders
03/12/2015	Smart grid metrics and CVR public meeting
04/10/2015	Draft report shared with key stakeholders
04/15/2015	Smart grid report workshop with key stakeholders
04/22/2015	Last day comments received

PGE received written comments from:

- **Oregon Public Utility Commission Staff** provided comments or questions on PGE's smart grid task force, customer research, Distributed Standby Generation, continuous communication upgrades, analytics, dynamic pricing, bulk thermal storage, and metrics.
- **Northwest Energy Coalition** provided comments or questions on strategy/future state, low income accessibility, future project vetting, smart water heaters, energy storage, electric vehicles, overloaded transformer analysis, and reliability metrics.
- **Renewable Northwest** expressed interest and approval of work being conducted at the Salem Smart Power Center and encouraged PGE to look for ways to scale up system flexibility beyond pilot projects.

Where applicable, PGE has included additional information in this report to address those comments.

PGE also conducts customer research on a regular basis to ensure our vision aligns with customer expectations regarding smart grid engagement.

Section 3. Smart Grid Strategy

A. Background

PGE has previously reported[1] a smart grid strategy consistent with OPUC's goals:

- *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).*

This strategy has been valuable in guiding PGE research, investment, and planning around smart grid technologies. However, due to the constantly evolving, cross-functional nature of smart grid deployments, PGE has recognized the necessity to develop a more integrated corporate-level strategy and vision of its future state to maximize the benefits of smart grid investments.

This year, PGE commenced a process to identify gaps and dependencies between PGE's strategies and to develop a clear cross-company vision, road map, and strategic approach to integrating and deploying smart grid technologies. A smart grid task force is evaluating industry best practices in smart grid deployment, to update PGE's smart grid vision, and to establish a smart grid future state and road map. The task force is exploring inputs from key subject matter experts from across the organization to define a model that is best for PGE and its customers.

[1] PGE Smart Grid Report 2013 & 2014

The task force includes SMEs from the following teams:

- Business Development
- Corporate Planning
- Corporate R&D
- Customer Insights
- Customer Specialized Programs
- Enterprise Telecommunications
- Information Technology
- Innovative Technologies
- Integrated Resource Planning
- Network Data Operations
- Rates & Regulatory Affairs
- Resource Strategy
- Retail Strategy & Development
- Strategic Asset Management
- Substation Administration
- System Protection & Automation
- T&D Engineering
- T&D Planning & Project Management

B. Smart Grid Maturity Model

Prior to developing a target future-state for PGE's smart grid, the task force has decided to evaluate its current state utilizing the Smart Grid Maturity Model (SGMM). The Smart Grid Maturity Model was created by a coalition of electric utilities and IBM in 2009 to serve as a strategic framework for utilities to develop explicit plans to advance smart grid infrastructure. The model is now maintained by Carnegie Mellon University's Software Engineering Institute (SEI) and has been utilized by dozens of utilities, including SDG&E, AEP, Austin Energy, CenterPoint, PG&E, Entergy, Puget Sound Energy and Duke Energy.

SGMM divides and evaluates the utility in eight domains to facilitate a framework for better understanding the extent of smart grid deployment and a context for establishing strategies and implementation plans. PGE established smart grid working groups that align with the SGMM's eight domains:

1. Strategy, Management, and Regulatory
2. Organization and Structure
3. Grid Operations
4. Work and Asset Management
5. Technology
6. Customer
7. Value Chain Integration
8. Societal and Environmental

The SGMM process is essential for developing a road map that is consistent with PGE's current state and corporate strategies. It calls for:

1. **Gather Information:** Evaluation and documentation of PGE's current state
2. **Analysis**: Develop pillars, benchmark performance, and identify best practices
3. **Articulate Vision & Future State:** inter-departmental input
4. **Vision & Road Map:** gap analysis, identification of key dependencies

C. Timeline

PGE is currently in the Articulate Vision & Future State phase of the maturity model and anticipates an opportunity for stakeholders to provide feedback in Q3-Q4, 2015. PGE anticipates reporting the final vision and road map in the 2016 Smart Grid Annual Report.

Figure 1 – PGE Smart Grid Road Map Projected Timeline

Task	2014				2015				2016			
Gather Information												
Analysis												
Articulate Vision & Future State												
Stakeholder Engagement												
Vision & Road Map												
Implementation												

Section 4. PGE Commitment to Smart Grid

A. Staff

Over the past 2 years, PGE has expanded its internal expertise and resources allocated to working on smart grid strategy and deployment. In addition to the many staff supporting smart grid efforts, these positions are dedicated to smart grid-related activities:

- Strategic Asset Management Smart Grid Data Analytics Engineer
- Customer and Smart Grid Data Analyst
- Emerging Technologies Project Engineer (will lead the development and demonstration of emerging technologies in solar, battery, and other technologies related to smart grid value propositions)
- Smart Grid Strategy and Projects Project Manager (will take on the development, coordination, and reporting activities)
- T&D Smart Grid Planning Engineer

B. Alignment with Integrated Resource Plan (IRP)

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.

C. Project Development Process

PGE utilizes a disciplined approach to evaluating new smart grid opportunities. The methodology is modelled after EPRI's *Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects*:

1. Describe the project
2. Identify Smart Grid functions provided
3. Assess project's principal characteristics
4. Map functions to benefits
5. Establish project baseline(s)
6. Identify and compile the data
7. Quantify the overall impact
8. Monetize the benefits
9. Estimate the relevant costs
10. Compare costs and benefits

PGE has a cross-functional committee that exists to promote, assess, and implement innovative technologies that require research and development. This team of SMEs assesses technologies and proposals on a regular basis to ensure projects align with PGE's smart grid strategy.

Additionally, PGE conducts customer research on a regular basis to ensure customer expectations are aligned with the company's Smart Grid efforts. PGE leverages this research to inform our product and program offerings and identify ways to better engage customers in the Smart Grid. Most recent targeted studies include an electric vehicle survey and a pricing program survey with subsequent focus groups.

As PGE develops pilots/studies, the Company will share results with OPUC staff and interested stakeholders, offering an opportunity for business cases for major investments to be vetted prior to deployment.

Section 5. Status of Current Smart Grid Initiatives

PGE has completed and is actively deploying a variety of smart grid initiatives across two categories: Grid Optimization and Customer Engagement. Previous reports have included Distributed & Renewable Resources as a third category. This category has been merged into Grid Optimization as these projects are increasingly expanding system capabilities and improving overall system performance. This section of the report summarizes smart grid initiatives across both categories that are completed or in progress.

A. Grid Optimization

Grid optimization initiatives are transmission, substation, and distribution systems investments in hardware, software, technologies, and processes that improve system reliability and efficiency, increase flexibility of grid integration, enhance the ability to reduce peak demand, and reduce overall utility operation costs.

Advanced Metering Infrastructure (AMI) Deployment

Description: Approved by OPUC Order No. 08-245, PGE installed digital Smart Meters at more than 825,000 customer locations along with dozens of communication towers.

Status: Complete

SCADA (Supervisory Control and Data Acquisition)

Description: Deployment of SCADA on substations increases visibility of the grid to T&D operations and reduces the likelihood and durations of outages. Currently 74% of PGE substations are controlled by SCADA. One existing substation and one new substation were added to the SCADA system in 2014. PGE is actively deploying SCADA controls at substations. PGE is also strategically adding SCADA to reclosers, tie switches, and other intelligent electronic devices (IEDs) that will increase the visibility of the grid to T&D operators.

Status: Active Deployment

Next steps: PGE anticipates SCADA deployment at an additional 6 substations and automation of 14 reclosers in 2015.

Conservation Voltage Reduction (CVR)

Description: CVR is the strategic reduction of feeder voltage deployed with phase balancing and feeder capacitor banks to ensure end-customer voltage is within the low range of ANSI (American National Standards Institute) acceptable voltages (114V – 120V). By reducing voltage 1.5% - 2.5%, PGE is able to reduce customer demand (MW) and energy consumption (MWh) by 1.4% - 2.5%. PGE completed feasibility studies and two CVR pilot projects in 2014 at Hogan South substation in Beaverton and Denny substation in Gresham. The pilots yielded customer energy savings of 768 MWh in 2014. A preliminary evaluation has identified 94 transformers as potential CVR candidates with a customer energy savings potential of 142,934 MWh/yr. (16 MWa). Additional analysis on the pilot projects is available in Appendix 4.

Status: Pilots & Evaluation

Next steps: PGE is focusing CVR efforts in 2015 on piloting communications networks to determine the optimal communication spectrum to monitor switched capacitor banks and customer voltage via AMI. Through 2017, PGE is developing advanced analytics to allow engineers to efficiently observe the status of CVR implementation. This will yield increased observability and customer-level alarms for instances of voltage levels outside of ANSI voltage limits. With a proper communications network and analytics to effectively deploy CVR, PGE anticipates a strategic deployment of CVR starting in 2018.

Overloaded Transformer Analysis

Description: PGE has built systems that utilize smart meter data to identify overloaded transformers. The tool collects interval energy data from all meters on a transformer to determine specific time and load of coincident peak demand on the transformer. To date the tool has identified 449 overloaded transformers. By proactively replacing overloaded transformers, the Company avoids potential feeder downtime and customer outages.

Status: Active Deployment

Next steps: PGE will continue to utilize the tool to identify overloaded transformers and may expand functionality to other assets over time. PGE will proactively replace overloaded transformers as resources are available.

Salem Smart Power Project (SSPP)

Description: 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. 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 concluded in 2014. Key project features 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 system efficiency and customer reliability.
- **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
- **Frequency Regulation**: PGE’s 5 MW, 1.25 MWh lithium ion battery inverter system at the Salem Smart Power Center has demonstrated an ability to respond to major system frequency events. In February, 2015, BPA Balancing Authority experienced a loss of 660 MW of generation. The automated battery response proved to be a fast and reliable tool to help stabilize WECC interconnection frequency.

Status: Complete (Research, Development, and Demonstration are on-going)

Solar Energy Grid Integration Systems (SEGIS)

Description: Initiated in 2008, SEGIS is a partnership between the U.S. Department of Energy (USDOE), Sandia National Laboratories, power-equipment manufacturers, electric utilities and universities to remove the barriers to large-scale general integration of photovoltaic (PV). The effort was expanded in 2011 as a part of the USDOE's SunShot Initiative and has demonstrated:

- Synchrophasor-enabled anti-islanding
- VAR control
- Ramp-rate control
- Power-factor control
- Low-voltage ride through
- Feeder optimization
- Power management functions

Effectively using renewable energy assets and the implementation of PMUs (Phasor Measurement Units) and smart inverters on the grid will enhance reliability and could help regulate power flow. These 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.

Additional information on utilizing smart inverters for PV resource integration can be found in Appendix 8.

Status: Complete

Dispatchable Standby Generation (DSG)

Description: PGE works with large customers that own onsite back-up power generators to provide a reliable, firm capacity resource. PGE maintains and fuels participating generators. PGE has 94 MW of capacity from these generators which contribute to the Company's non-spinning reserves.

Status: Active Deployment

Next Steps: The Company intends to achieve 125 MW of DSG within the next five years.

Remote Service Detection (Outage Confirmation)

Description: PGE has built systems that utilize Smart Meter data to confirm outages prior to dispatching crews. Smart meters are 'pinged' when customers report an isolated outage, avoiding unnecessary truck rolls in situations where PGE service to the home has not been interrupted.

Status: Complete

Substation Automation

Description: Expansion of SCADA and IEDs such as microprocessor relays are allowing increased levels of automation at substations. These efforts provide faster isolation of faults and improve system reliability.

- **Automatic switching**: distribution substations automatically attempt to restore power after outages
- **Automated protection schemes**: enables automatic transfer to alternative transmission source in the event of a transmission outage

Status: Active Deployment

Next steps: PGE anticipates continued deployment of substation automation at new substations and on existing stations as a part of regular upgrades.

Substation Remote Access Server

Description: In 2014, PGE activated a substation remote access server which allows remote visibility to IEDs which speeds up restoration time and saves on operation & maintenance costs. Additionally it provides access to data related to asset monitoring, disturbance monitoring, and real-time operations. Currently, 18% of substations are connected to the Substation Remote Access Server.

Status: Active Deployment

Next steps: PGE anticipates continued deployment of substation remote access server at new substations and on existing stations as a part of regular upgrades.

Continuous Communication Upgrades

Description: PGE is actively upgrading fiber and wireless communications networks to enable 2-way communications to the constantly evolving network of IEDs and the data they create. Enhanced communication networks are fundamental to a fully functioning smart grid—upgrades enable device monitoring, control, and remote asset management. Communications infrastructure meets NERC Critical Infrastructure Protection (CIP) compliance requirement.

Status: Active Deployment

Next steps: In order to accommodate future smart grid initiatives such as distribution automation, synchrophasors, demand response, etc., PGE has been evaluating the opportunities for procuring a large block of radio spectrum for late 2015 or 2016.

T&D Asset Monitoring

Description: By installing IEDs on many large capital assets, PGE is promoting a more reliable grid and increased asset utilization. Dissolved Gas Analyzers (DGAs) monitor dissolved gas in system transformers. Changes in dissolved gas characteristics could indicate a deterioration of device health and imminent asset failure. This type of proactive monitoring allows PGE to practice condition-based maintenance as opposed to time-based maintenance, optimizing Company resources.

PGE has installed advanced transformer sensors to monitor dissolved-gas on 28 of 41 critical transformers. Though no DGAs were installed in 2014, the Company plans to upgrade an additional seven units in 2015 and the remaining units by 2018. The Company is also installing DGAs on non-critical transformers on a case-by-case basis.

Status: Active Deployment

Next steps: In the next couple of years PGE intends to evaluate installing similar sensors on other system assets such as circuit breakers and substation batteries. Real-time sensor information from these devices could result in optimized maintenance schedules and prevented device failures and outages.

T&D Analytics

Description: PGE has begun an advanced analytics pilot program to leverage the massive amounts of new data available via IEDs on the T&D system. This pilot project will utilize existing data streams, such as AMI data, to produce actionable information required to enhance planning and operations activities on PGE's T&D system.

Status: Pilots & Evaluation

Next steps: In 2015, PGE will utilize the analytics platform to create interactive dashboards, conduct event analyses, and create system alarms for meter diagnostics, network performance, and overloaded transformers.

In future years, PGE will continue evaluating evolving best practices and will utilize the analytics platform to perform circuit analysis: feeder-level insights utilizing aggregated AMI data will help inform asset management initiatives.

Anticipated results include improved service restoration times, increased system modeling accuracy and capabilities, and enhanced asset replacement and maintenance strategies.

Distribution Automation (DA)

Description: DA refers to a distribution system that is fully controllable and provides the potential for self-correcting and self-sustaining distribution feeders or microgrids where distributed energy resources (DERs) and/or energy storage exists. DA systems are capable of isolating faulted line segments and restoring power to other customers on the feeder within one minute. In the past, those customers were sometimes out for several hours. The DA system can be monitored and controlled via SCADA.

PGE deployed a DA pilot at Gales Creek in 2012 and plans to utilize DA technology for research at the Salem Smart Power Center. DA has resulted in operational savings and System Average Interruption Duration Index (SAIDI) reductions for customers served by the Gales Creek system:

Table 4 – Gales Creek Reliability Metrics, 2006-2014[2]

Year	2008	2009	2010	2011	2012	2013	2014
SAIFI	3.4	5	4.1	2.6	3.9	0.6	1.7
SAIDI (min)	1,115	1,134	1,278	448	695	116	252
# of Outages	45	59	41	41	51	21	37

Status: Pilots & Evaluation

Next steps: PGE is evaluating technologies deployed in the DA pilots and is developing a strategic plan for future DA deployment. PGE expects a formal plan to be developed in 2015. PGE plans to utilize strategic asset management tools to inform when and where to deploy DA. PGE expects future DA deployment to begin in 2016-2017.

[2] PGE Reliability Reports 2008-2014

Energy Management System (EMS) & Automated Generation Control (AGC)

Description: PGE has deployed a modern Energy Management System (EMS) and Automated Generation Control (AGC) for our generation and transmission systems. These tools allow for centralized control of distributed resources and advanced analytics on historic data to optimize system performance.

Status: Complete

Fault Detection (Distribution)

Description: A pilot is underway to install Faulted Circuit Indicators (FCIs) on five feeders and integrate the data via AMI communications infrastructure. FCIs have been deployed at Middle Grove and will be expanded to four additional feeders in 2015. In 2016, PGE will evaluate the cost-benefit of the FCI deployment and determine whether or not to invest in FCIs for more feeders along with necessary server upgrades. The Company anticipates the pilot should result in improved reliability metrics.

Status: Pilots & Evaluation

Next steps: If the pilot is successful, a strategic deployment of FCI infrastructure could occur starting in 2017.

Voltage Disturbance Detection (i-Grid)

Description: Voltage disturbances (including sags, swells, interruptions, and outages) are the most common power quality problems. PGE has installed i-Grid detection devices that capture and record voltage disturbances, as well as long-term voltage trends. Voltage reporting allows for engineers to perform post-event analysis and diagnose system issues which could result in proactive equipment replacement. To date, PGE has installed i-Grid 102 devices on 98 feeders.

Status: Limited Deployment

Next steps: PGE will continue limited, strategic deployment of voltage disturbance detection devices. Additionally, PGE will evaluate additional ways how to leverage voltage reports such as enhancing asset monitoring capabilities.

Energy Management System (EMS) State Estimator (SE)

Description: To optimize the operation and reliability of the transmission system, PGE has developed a system model for an EMS SE. The model reads system data from the SCADA system (voltage, line flows, etc.) and performs power flow simulations to give insight into the state of the grid.

Status: Planned Deployment (after testing complete)

Next steps: A fully functioning state estimator is anticipated to deploy in Q3 of 2015. The tool will better inform decisions made by operations personnel for reliable operation of the transmission system.

Real-time Contingency Analysis (RTCA)

Description: RTCA is a situational awareness tool that runs contingency on the SE. The model runs power flow for defined contingency scenarios (loss of line, transformer, or any other element in the system). The model then ranks the overall impact of potential system operating limit concerns (thermal overloads, voltage issues). This enables pre-contingency mitigation strategies to be employed to address the potential impact of a particular outage scenario.

Status: Planned Deployment

Next steps: PGE has completed contingency models for select 230kV and 115kV lines and will integrate RTCA in T&D operations in Q4, 2015.

Synchrophasors on Transmission System

Description: Synchrophasors provide enhanced system situational awareness for transmission operators and planners by providing real-time system information. Phasor measurement units (PMUs) capture data at a higher resolution than typical grid monitoring devices and include more depth of information beyond voltage and frequency, including GPS, and time stamped phasor quantities. A wide deployment of PMUs and phasor data concentrators (PDCs: IEDs that collect and aggregate data from PMUs), communications infrastructure, and analytics software can lead to:

- Enhanced situational awareness
- Improved visibility into interconnection points with adjacent utilities and regional flowgates[3]
- Detailed post-event analysis
- Generation model validation and test avoidance (reduced down time of generation facilities)
- System state model validation

PGE is strategically deploying PMUs and PDCs at critical transmission facilities to realize these benefits. To date, PGE has deployed synchrophasor technology at 1 transmission substation (Rosemont).

Status: Pilots & Evaluation

Next steps: Deployment of synchrophasor technology is scheduled for two additional substations in 2015 and 10 additional over the next few years. In addition to PMU and PDC installation in the field, PGE has invested in critical server infrastructure and software that will enable the Company to realize the maximum benefits of this technology. Server installation is expected to be complete in late 2015.

Additional detail on PGE's investment in synchrophasors is in Appendix 6.

[3] PGE is evaluating participation in WISP (Western Interconnection Synchrophasor Program) which works to increase grid operators' visibility into bulk power system conditions, allow earlier detection of grid stability threats, and facilitate PMU data transfer with neighboring control areas: https://www.smartgrid.gov/project/western_electricity_coordinating_council_western_interconnection_synchrophasor_program

Travelling Wave Fault Location Protective Relays

Description: PGE has completed the installation of Travelling Wave Fault Location Protective Relays on the Bethel-Round Butte (230kV), Shute-Sunset (115kV), and Grassland-Slatt, BPA (500kV) lines. 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 technology will enable PGE to accurately locate faulted sections without helicopter dispatch, saving $24,000 per event.

Status: Limited deployment

Next Steps: Continued deployment at select transmission lines.

Remedial Action Schemes (RAS)/Special Protection Scheme (SPS)

Description: A RAS is an automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability.[4] PGE has established RAS at Grand Ronde & is designing a RAS at Rounde Butte. These schemes leverage the EMS SE & RTCA to help PGE maximize its T&D infrastructure and defer capital investments.

Status: Limited Deployment

Next steps: Evaluate opportunity after full deployment of the EMS SE and RTCA tools.

Distribution Temperature Sensing (DTS)

Description: PGE has installed real-time line sensors on six network feeders in the Company's service territory. These linear sensors give visibility to temperatures of subterranean cables at 2 second intervals. Because temperature affects capacity, insight into the temperature better informs PGE of the timing and need for future system upgrades. DTS also allows PGE to recognize unusual hot spots which could indicate a pending cable failure.

Status: Limited Deployment

Next steps: PGE is including DTS in designs for a new substation expected to go into service in 2018-2019.

[4] NERC "Remedial Action Scheme Definition Development"

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. The 'NextWave Project' will replace approximately 30 antiquated enterprise systems with more efficient and integrated tools that will make information more accessible and will enable advanced data analytics and process automation. The following tools are foundational in PGE's grid optimization efforts:

Outage Management System (OMS)

Description: A new 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 to analyze.

Status: Planned Deployment

Next steps: The new OMS is scheduled to be deployed in 2015.

Geographical Information System (GIS)

Description: A modern GIS can provide an accurate, as-built view of all components of the electrical grid and brings data together for improved field operations, customer service and analysis. ESRI ArcGIS 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 realizing many smart grid benefits:

- Advanced control and monitoring of asset network
- Visualization of reliability metrics
- Advanced geospatial analytics
- Large data visualization

Status: Planned Deployment

Next steps: The new GIS suite will be deployed at PGE in 2015.

B. Customer Engagement

Customer engagement initiatives are investments in energy information systems, pricing programs, demand response, and system development. These initiatives aim to improve the customer experience, save energy, and reduce peak demand.

Energy Tracker

Description: Energy Tracker is an energy information platform 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 apps via the Green Button
- 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
- Forecasted bill (for residential customers)
- Text/e-mail alerts

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 165,000 customers to control their electricity bills by helping them understand when and how they are using electricity. Energy Tracker customers have reduced their annual energy consumption 3% faster (332 kWh) than non-Energy Tracker customers.[5]

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, the Company 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 through the information with a customer during the course of an audit

Status: Active Deployment

Next steps: PGE is considering an update to Energy Tracker after the completion of CET (likely in 2016-2017).

[5] Energy Tracker savings data is based on program evaluation in 2013.

Energy Expert

Description: Energy Expert is an advanced energy monitoring platform available to PGE large commercial and industrial customers for a fee. Energy Expert uses 15-minute interval meter data to give customers a highly accurate view of energy consumption over time.

PGE has offered Energy Expert for over 10 years, and the current version of Energy Expert (version 5) has been available since January 2013. Energy Expert features include:

- Display of advanced customer energy information data (consumption, historic trends, load profiles, cost savings opportunities, peak reports)
- Identification of abnormalities or areas for operational improvements
- Consolidation of weather data, time of day, day of week to predict energy usage
- Notifications and alerts
- Calculation of energy savings to track the effects of energy conservation activities

To help ensure that PGE's business customers are aware of the Energy Expert tool, PGE holds webinars, workshops and onsite demonstrations to help potential user understand the benefits of monitoring daily energy usage. Currently 97 customers are utilizing Energy Expert on over 500 meters.

Status: Active Deployment

Next steps: In 2015, PGE will provide customers the option of upgrading to the new version 6 platform for no additional fee; it includes:

- Faster access to data using configurable dashboards
- Improved mobile access and functionality

Providing these customers with the ability to monitor consumption and make informed decisions about energy usage can have a significant impact on total energy demand each year.

Commercial and Industrial Time-of-Day Pricing (TOD)

Description: PGE offers TOD pricing via Schedules 83, 85, and 89. All customers with monthly demand in excess of 30 kW are on a time-varying pricing program. The program has approximately 12,000 customers enrolled.

Status: Active Deployment

Residential and Small Commercial Time-of-Use Pricing (TOU):

Description: A voluntary program available to customers with up to 30kW of demand available via Schedules 7 and 32. The program has approximately 2,300 residential customers enrolled. For the past decade, PGE has limited promotion of the program 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 AMI, PGE is re-evaluating whether to promote the program. It is actively promoted to EV drivers today.

Status: Active Deployment

Flex Price/Critical Peak Pricing (CPP)

Description: PGE launched a two-year CPP pilot project in November 2011. The pilot was offered to 1,000 customers via Schedule 12. 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 peak time events for up to 4 hours each, during which the customers' energy price was approximately five 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 appeared to be a small TOU effect on usage. Customer satisfaction with the program was low (65%) compared to other pricing programs (75 – 85%).

Status: Complete

Pricing Pilot Development Research

Description: In 2014, PGE began a strategic effort to evaluate pricing program types and barriers to customer participation. PGE completed a market research that included surveys and focus groups to help inform a pilot offering. PGE also leveraged AMI data to conduct load segmentation research, identifying 5 load profiles that can be targeted for demand response and pricing initiatives.

Status: Complete

Next Steps: PGE has a deferral for a proposed dynamic pricing pilot before the OPUC and is targeting a March, 2016 launch. The pilot will employ a variety of tactics including peak-time rebates (non-punitive reward for customers who reduce load during peak periods) and new TOU rates.

Firm Load Reduction for Commercial & Industrial Customers

Description: PGE offers demand response (DR) to large non-residential customers who are able to commit to a 4-hour load reduction of at least 200 kW of demand at a single point. This program was launched in 2010 via Schedule 77. 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.

Status: Active Deployment

Energy Partner

Description: PGE launched the Energy Partner automated demand response (ADR) pilot in 2013. It uses automated controls to enable participating customers to respond to event signals within as little as 10 minutes. The program is available to customers with 30kW of demand or higher. The program currently is currently capable of load reduction of 8 MW for summer 2015.

Status: Active Deployment

Next Steps: After 2016, PGE will evaluate whether to transition from a pilot to an official program, at which point demand reductions would be treated as a firm capacity resource, helping meet the forecasted capacity shortfall identified in our IRP and also qualifying as non-spinning reserves.

Salem Smart Power Residential Direct Load Control

Description: A 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.

Status: Complete

Next Steps: PGE is working with EPRI on a new pilot program listed in the future initiatives section of this report.

Smart Thermostat Direct Load Control (DLC) Pilot

Description: Leverage internet-connected smart thermostats as a demand response asset.

Status: Planning Pilot

Next Steps: PGE has a deferral for a smart thermostat DLC pilot before the OPUC and is targeting a 2016 launch. PGE would offer an incentive to customers who own a smart thermostat and will provide a seasonal subsidy for participation in the pilot. PGE recognizes smart thermostats as a practical application of an in-home display (IHD)—wider scale adoption of smart thermostats could lead PGE to consider an integrated IHD program.

Systems Development

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. PGE will be replacing its 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.

Section 6. Research & Development

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 proposed for 2015 and 2016. Many projects leverage and expand upon existing or planned smart grid initiatives. These projects are subject to funding through PGE's current general rate case (Docket No. UE 294). Final RD&D project list or funding may vary depending on final rate case determination. Proposed budgets for these projects can be found in PGE Exhibit No. 604 (UE 294). Detailed project descriptions are included in Appendix 3.

Table 5 – PGE RD&D Projects, 2015-2016

Project
SSPP Battery-Inverter Response to Transactive Signal
5 MW Load Response to Under Voltage Load Shed Event
SSPP Real time Solar Integration Algorithms Automation
Frequency Response Test - Automated Deployment
Adaptive (Dynamic) Voltage Control
Using the SSPP as a Dispatchable Standby Generator
Survey of Distributed Power Gen & Energy Storage Capability
Assessing Energy Storage as a Non-Wire Alternative for T&D
EPRI Information & Communication Technology Program
Using the SSPC as a Smart Grid Energy Storage Test Facility
Evaluation of Operating Fuel Cells
Hybrid Microgrid Creation with Full Island Capability - Model Criteria
Testing and Integration of Smart Inverter Functions
Joule Bank System (JBS)
EPRI Integrated Grid Program

Section 7. Future Smart Grid Investments

A. Opportunities for Next 5-10 Years

Electric Vehicle (EV) Charging Programs

With over 700 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 Oregon to grow from about 6,000 today to 30,000-40,000 by 2020. PGE has created a substantial EV charging infrastructure which could enable a variety of smart grid programs in the future. PGE is tracking the EV market and evaluating technologies that could serve as demand or supply-side resources for PGE's resource portfolio.

Smart Charging

Description: As ownership of EVs increases over time, DR-enabled vehicles or charging stations could prove to be a high impact demand-side resource for the Company's IRP.

Status: Planning Pilot

Next Steps: PGE is collaborating with EPRI in studying the interoperability of smart appliances. PGE is working to launch a pilot in 2016 to explore DR with EVs and charging stations. Approximately 10 EV drivers will participate in a centrally managed charging process that signals cars or charging stations to adjust demand in real-time to optimize resource and system utilization.

Other EV Programs

Description: Future RD&D/pilot projects may explore these concepts:

- **Timed Charging**: Timers in EVs or charging stations will enable more off-peak charging.
- **Vehicle to Home**: EVs to provide back-up power to residential homes through outlets or a service-panel connection.
- **Vehicle to Grid (V2G)**: 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**: utilizing car batteries after their primary life in homes and businesses as an alternative to building supply-side resources for optimizing resources and shifting load.

Status: Future Initiative

Next Steps: PGE is collaborating with vehicle and charging station manufacturers in consideration of developing future pilot programs.

Distribution Management System (DMS)

Description: DMS is foundational to a smart T&D infrastructure and is necessary to get the maximum value of DA. 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. 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.

Status: Future Initiative

Next Steps: PGE is considering adding a DMS in the 2018-2020 timeframe, however, a deployment is not likely until there are a number of DA projects being deployed.

Microgrids

Description: PGE is planning a microgrid market assessment to determine service territory-wide potential for future microgrid projects. Microgrids could employ a variety of technologies such as diesel generators, on-site generation, batteries, etc. to allow full islanding from PGE’s grid.

Status: Research

Synchrophasors on Distribution System

Description: Deployment of PMUs and PDCs on PGE's distribution system could result in enhanced situational awareness and more effective DA. PGE has deployed 5 PMUs on a feeder in Canby as a part of the SEGIS initiative. These PMUs primarily inform solar research, however they could inform a future deployment of synchrophasor technology on the distribution system.

Status: Future Initiative

Next Steps: PGE anticipates a full evaluation of the technology and the opportunities for synchrophasors on its distribution system in the 2018-2020 timeframe.

Home Battery Back-Up System

Description: In collaboration with Portland State University (PSU), PGE has developed a laboratory prototype of a battery/inverter system with a mock house and mock grid to demonstrate charge and discharge of a home battery at various power levels. The project serves to test end-to-end controls and equipment specifications required to utilize a battery to power an entire home during an outage and as a utility peaking resource capable of storing excess wind energy at night.

Status: Research

Next Steps: PGE is working to deploy a field demonstration at a house or small business/municipal facility in 2015 or 2016. If the demonstration proves successful then a pilot program may be developed with the long-term goal of creating a program where these systems would serve as a capacity resource to leverage as additional renewables are integrated into the grid.

Bulk Thermal Storage

Description: PGE is collaborating with PSU and Harvey Mudd College to test control requirements and the energy efficiency gains of a purpose-built thermal storage unit installed in a residential premise. The research would leverage a home's space and hot water pumps by drawing on a thermal reservoir to meet the customer demand.

Status: Research

Next Steps: If research proves viable, PGE could run a pilot in which the Company 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).

Smart Water Heaters

Description: PGE is in final stages of preparing to launch a small water heater demand response 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. The pilot project will involve ten residential customers receiving a water heater with a modular communications interface. Currently one unit is being tested in a lab setting to inform ideal settings for the pilot program.

Status: Planning Pilot

Next Steps: PGE anticipates the pilot to launch in 2015.

Strategic Deployment of Distributed Energy Resources

Description: PGE's planned GIS system paired with AMI data and T&D planning processes could provide better insight into where our peak summer loads are and where overloaded equipment is. With these tools, the Company may evaluate strategic deployment of intermittent resources such as solar in locations where the impact could defer or offset capital investment or maintenance.

Status: Future Initiative

Next Steps: PGE will explore these possibilities after the 2015 launch of GIS.

Prepaid Metering

Description: 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.

Status: Future Initiative

Next Steps: 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.

Green Button 2.0

Description: 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. Currently, less than 1% of customers who log on to Energy Tracker ‘press’ the Green Button.

Status: Future Initiative

Next Steps: Evaluate feasibility of adding Green Button 2.0 during next major Energy Tracker update (post-CET). Green Button usage trends will be taken into account in any decision to expand the availability of this program.

Section 8. Related Activities

A. Physical Security (Hardening)

Though many smart grid technologies improve system resilience to downed wires, poles, and other T&D equipment, PGE is continually looking beyond automation for cost-effective ways to improve the physical integrity of the Company's assets. PGE has an industry-leading vegetation management program and is taking significant efforts to improve critter control efforts and asset security.

B. Information Technology

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 cyberattacks, 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 (CCS), 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. Additionally, PGE is adopting the National Institute of Standards and Technology's (NIST) smart grid interoperability, security, and privacy standards. These standards outline best practices that are utilized across the industry.

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 CCS in secure-by-default infrastructure zones
- Extend virtualization and virtualization security benefits to CCS
- Improve posture-assessment capability for remote access
- Implement CIP compliance for network systems and substation remote access Substation Remote Access was installed to ensure secure data gathering & access to substation IEDs in compliance with NERC CIP standards.
- Mitigate the impact of new NERC requirements (for example, CIPv5) to utility systems
- Implement technology to provide trusted computing environments within hardware systems

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. [6]

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

C. Strategic Asset Management

T&D Strategic Asset Management (SAM) is a program launched in PGE's Customer Service, Transmission and Distribution group in 2013. The program supports risk management activities in the T&D asset base by identifying high risk assets and asset systems, evaluating the relative merit of different risk reduction options, and advocating for risk reduction investments that demonstrate the most value to customers and PGE. Primary deliverables produced by SAM include economic life models for significant T&D asset classes and asset systems; long-range strategic plans for risk reduction in the asset base; and capital investment recommendations to support plan execution. The primary risk factors evaluated by SAM include threats to reliability (aging assets, assets in poor condition, assets with very high customer counts or loading), safety and environmental threats, and threats to effective cost management.

In 2014, SAM assessed PGE's most critical substation asset classes; a sizeable multi-year substation risk reduction program is in development now. In 2015, SAM is modeling individual distribution asset classes to identify high risk assets and feeders. SAM will use these base models to evaluate the application of Smart Grid technologies across the distribution system, and ascertain where such technologies make economic sense for customers and PGE given their costs and risk reduction benefits (e.g., shortening average outage durations).

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

D. Low Income Customer Engagement

It is important that new program initiatives are accessible and meet the needs of all PGE customers. Though PGE does not collect income data from customers, PGE ensures that the needs of economically disadvantaged customers are considered through a variety of efforts in research, program development, outreach, and OPUC engagement. In 2014, PGE conducted focus groups with economically disadvantaged customers to better understand customer awareness of programs and communication preferences. In addition to targeted focus groups, PGE actively monitors themes of "customer voices" via call logs, emails, and other communications employees have with customers. A PGE cross-functional team also facilitates biannual CAA meetings to talk openly about challenges and creative solutions with key community stakeholders. All of these insights collectively help inform how PGE markets and develops programs.

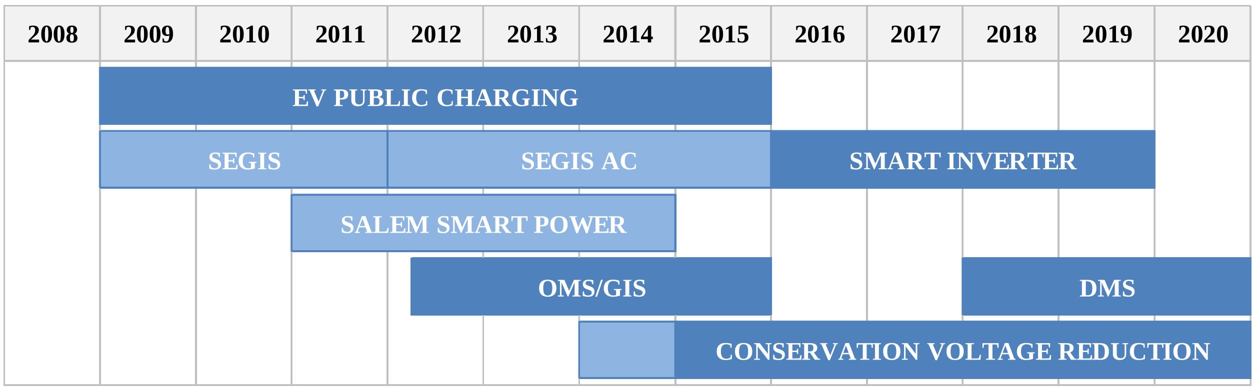
PGE provides CAAs with information and marketing collateral to distribute to customers that educate them about tools available to help them manage their energy use and bills such as Energy Tracker, mobile alerts, Preferred Due Date, and Equal Pay. In addition to providing materials for these organizations, PGE is working to develop programs that respond to the requests of this customer base. Most recently this can be seen as the Company engaged a lower income customer segment in pricing program focus groups. That segment responded positively to peak time rebates as a risk-free, non-punitive pricing program. As a result, peak time rebates will be explored in the upcoming pricing pilot.

Furthermore, PGE has been and will continue to be engaged in the OPUC process to evaluate alternative customer assistance programs.

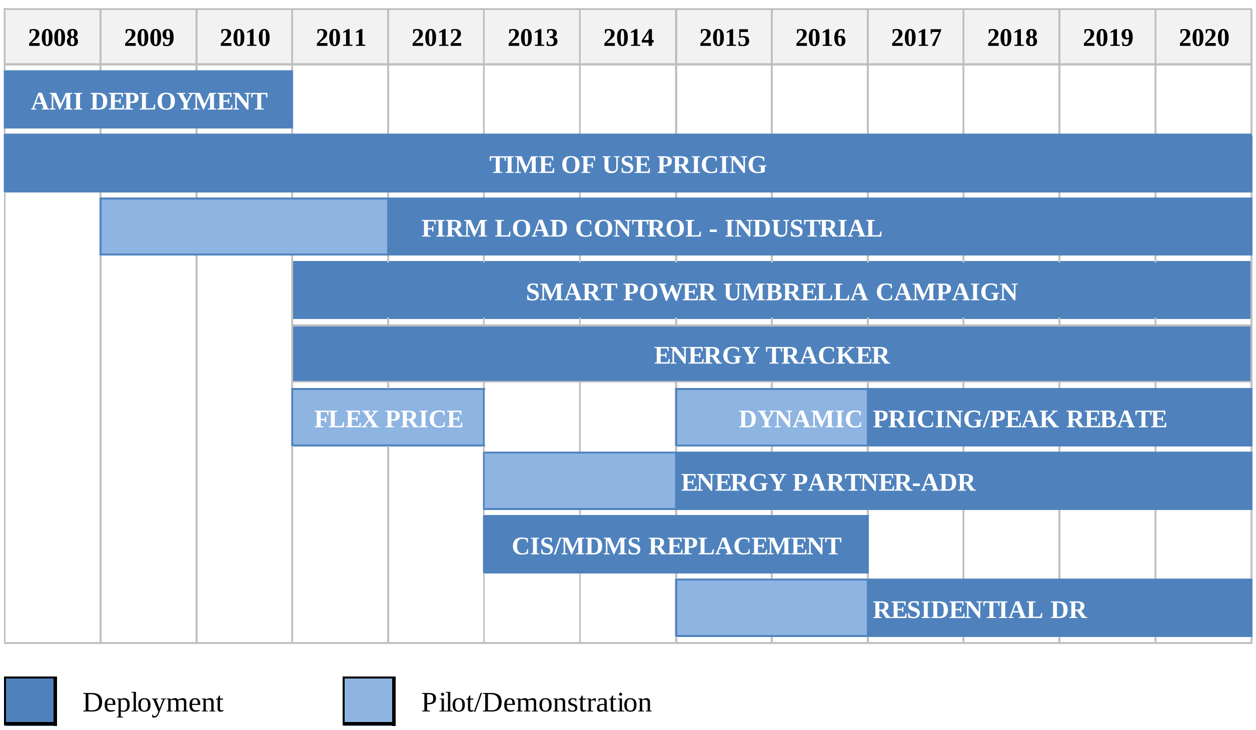
Section 9. Road Map

As discussed in Section 3, PGE is undergoing a comprehensive process to develop a new smart grid strategy, vision, and road map. A new road map will be a result of these efforts, however, the road map reported in the previous annual report is included below for reference:

Grid Optimization



Customer Engagement



Appendix 1. Summary of All Smart Grid Initiatives

Table 6 – Summary of All Smart Grid Initiatives

Initiative	Status	Page
Advanced Metering Infrastructure	Complete	17
Automated Generation Control	Complete	24
Bulk Thermal Storage	Research	38
Communications upgrades	Active Deployment	21
Conservation Voltage Reduction	Pilots & Evaluation	18
Customer Information System	Planned Deployment	33
Demand Response: Energy Partner	Active Deployment	32
Demand Response: Firm Load Reduction	Active Deployment	32
Demand Response: Residential Direct Load Control	Complete	33
Dispatchable Standby Generation (DSG)	Active Deployment	20
Distribution Automation	Pilots & Evaluation	23
Distribution Management System (DMS)	Future Initiative	36
Distribution Temperature Sensing	Limited Deployment	27
EMS State Estimator	Planned Deployment	25
Energy Expert	Active Deployment	30
Energy Management System	Complete	24
Energy Tracker	Active Deployment	29
EV Charging Infrastructure	Complete	35
EV: Second-life battery for home or grid	Future Initiative	35
EV: Smart Charging	Planning Pilot	35
EV: Timed Charging	Future Initiative	35

Initiative	Status	Page
EV: Vehicle to Grid	Future Initiative	35
EV: Vehicle to Home	Future Initiative	35
Fault Detection (Distribution)	Pilots & Evaluation	24
Geographical Information System	Planned Deployment	28
Green Button 2.0	Future Initiative	39
Home Battery Back-Up System	Research	37
Meter Data Management System	Planned Deployment	33
Microgrid	Research	36
Outage Management System	Planned Deployment	28
Overloaded Transformer Analysis	Active Deployment	18
Prepaid Metering	Future Initiative	39
Pricing Program: Critical Peak Pricing	Complete	31
Pricing Program: Pricing Pilot Development Research	Complete	31
Pricing Program: Time-of-Day Pricing	Active Deployment	30
Pricing Program: Time-of-Use Pricing	Active Deployment	31
Real-time Contingency Analysis	Planned Deployment	25
Remedial Action Schemes/Special Protection Schemes	Limited Deployment	27
Research & Development	Research	34
Remote Service Detection (Outage Confirmation)	Complete	20
Salem Smart Power Project	Complete	19
SCADA	Active Deployment	17
Smart Inverters	Research	89
Smart Thermostat Demand Response	Planning Pilot	33
Smart Water Heaters	Planning Pilot	38

Initiative	Status	Page
Solar Energy Grid Integration Systems (SEGIS)	Complete	20
Strategic Deployment of Distributed Energy Resources	Future Initiative	38
Substation Automation	Active Deployment	21
Substation Remote Access Server	Active Deployment	21
Synchrophasor Deployment (Distribution System)	Future Initiative	37
Synchrophasor Deployment (Transmission System)	Pilots & Evaluation	26
T&D Analytics	Pilots & Evaluation	22
T&D Asset Monitoring	Active Deployment	22
Travelling Wave Fault Location Protective Relays	Limited Deployment	27
Voltage Disturbance Detection (i-Grid)	Limited Deployment	24

Appendix 2. Smart Grid Metrics

OPUC Condition: Conduct workshops to explore how to best measure & track benefits of Smart Grid investments.

Table 7 – Asset Optimization Metrics

Metric	2012	2013	2014	3-yr Avg.
# Transformers > 80% Loaded[7]	17	15	19	17
# Feeders > 66% Loaded or > 12 MVA	53	51	51	52
Efficiencies realized through CVR (MWh)	-	356	768	375
System Risk Holding ($)	*Potential Future metric: Not yet capturing*			
System Risk Mitigated ($)	*Potential Future metric: Not yet capturing*			

Table 8 – Reliability Metrics, Corporate Summary

Metric		2012	2013	2014	3-yr Avg.
Including Major Event Days[8]	SAIDI	136	205	245	195
	SAIFI	0.72	0.57	1.2	0.83
	MAIFI	1.1	0.9	1.3	1.1
	CAIDI	189	360	204	251
Excluding Major Event Days	SAIDI	72	62	93	76
	SAIFI	0.55	0.45	0.69	0.56
	MAIFI	1.1	0.9	1.3	1.1
	CAIDI	131	138	135	135
% Substations with SCADA		70%	70%	74%	71%
% Critical Transformers w/ DGA		68%	68%	68%	68%
ASAI, CEMI, & CELID		*Potential Future metric: Not yet capturing*			

7 Consistently overloaded transformers based on normal system configuration

8 A Major Event Day is a day in which the daily system SAIDI exceeds a threshold value that is computed via the IEEE Standard 1366 (IEEE Guide for Electric Power Distribution Reliability Indices) methodology. This methodology is used by PGE to calculate distribution system performance indices and utilizes the Major Event Day (MED) designation as a basis for evaluation of system performance. The purpose of MED designation is to allow major events to be studied separately from daily operation, and in the process, to better reveal trends in daily operation that would be hidden by the large statistical effect of major events. As a result, PGE captures and reports system performance metrics both including and excluding Major Event Days.

Table 9 – Reliability Metrics by Region, Central

Metric		2012	2013	2014	3-yr Avg.
Including Major Event Days	SAIDI	90	86	215	130
	SAIFI	0.58	0.55	1.04	0.72
	MAIFI	1.7	1.6	1.5	1.6
	CAIDI	155	156	207	173
Excluding Major Event Days	SAIDI	51	54	91	65
	SAIFI	0.41	0.41	0.65	0.49
	MAIFI	1.7	1.6	1.5	1.6
	CAIDI	124	132	140	132

Table 10 – Reliability Metrics by Region, Eastern

Metric		2012	2013	2014	3-yr Avg.
Including Major Event Days	SAIDI	306	163	364	278
	SAIFI	1.2	0.88	1.98	1.35
	MAIFI	1.6	1.0	1.9	1.5
	CAIDI	255	185	184	208
Excluding Major Event Days	SAIDI	112	103	145	120
	SAIFI	0.81	0.77	1.05	0.88
	MAIFI	1.6	1.0	1.9	1.5
	CAIDI	138	134	138	137

Table 11 – Reliability Metrics by Region, Southern

Metric		2012	2013	2014	3-yr Avg.
Including Major Event Days	SAIDI	108	97	224	143
	SAIFI	0.61	0.45	0.82	0.63
	MAIFI	0.6	0.40	0.9	0.6
	CAIDI	177	216	273	222
Excluding Major Event Days	SAIDI	78	47	67	64
	SAIFI	0.53	0.30	0.40	0.41
	MAIFI	0.6	0.40	0.9	0.6
	CAIDI	147	157	168	157

Table 12 – Reliability Metrics by Region, Western

Metric		2012	2013	2014	3-yr Avg.
Including Major Event Days	SAIDI	86	400	208	231
	SAIFI	0.60	0.46	1.08	0.71
	MAIFI	0.7	0.70	1.1	0.8
	CAIDI	143	870	193	402
Excluding Major Event Days	SAIDI	61	50	78	63
	SAIFI	0.51	0.36	0.67	0.51
	MAIFI	0.7	0.70	1.1	0.8
	CAIDI	120	139	116	125

Note: future metric – reliability metrics by customer type (res. comm., ind.)

Table 13 – Customer Engagement Metrics

Metric		2012	2013	2014	3-yr Avg.
Total # Customers that have utilized Energy Tracker	Residential	79,702	123,508	165,004	122,738
	Commercial	728	1,440	2,462	1,543
	Total	80,430	124,948	167,466	124,281
Energy Tracker Realized Savings[9]		3%			
# Customer Utilizing Energy Expert		40	101	97	79
# of Customer Accounts of TOU Rate Schedule	Residential	2,287	2,313	2,303	2,301
	Commercial	1,630	1,672	1,794	1,699
	Industrial	132	131	129	131
	Total	4,049	4,116	4,226	4,130
# Customers participating in DR	Residential	-	-	-	-
	Commercial	-	3	23	9
	Industrial	4	4	4	4
	Total	4	7	27	13
Available capacity of DR (MW)		16	16	25	19
# Customers participating in DSG		29	33	34	32
Dispatchable capacity of DSG (MW)		79.4	83.4	94.0	85.6
Capacity of customer-owned renewable (MW)[10]		28.6	35.8	44.5	36.3
Number of customer programs[11]		7	7	7	7

[9] Energy Tracker savings data is based on program evaluation in 2013
[10] Includes solar, wind, hydro, fuel cell, and methane gas. Capacity is reported in MW-AC. Inverter-based technologies (solar and wind) include an 85% DC-to-AC derate factor.
[11] Includes energy information services (Energy Tracker & Energy Expert), demand response (Schedule 77 & Energy Partner), pricing programs (TOU and TOD), and distributed generation (DSG); Note: Does not include pilots

Table 14 – Customer Engagement Metrics:
(% Participation in Each Program Type by Segment, 2014)

Segment	Residential	Commercial	Industrial
Avg. # of Retail Customers[12]	735,502	105,231	260
% Participation in each program type			
Energy Information Services	22.4%	2.4%	14.6%
Demand Response	-	~0%	1.5%
Pricing Program	0.3%	1.7%	49.6%
Distributed Generation	0.7%	0.5%	7.31%

Table 15 – Total Number of AMI Meters Deployed
(By Year, Customer Type)

Customer Type	2012	2013	2014
Residential	735,134	741,889	748,722
Commercial	102,402	104,015	105,366
Industrial	4,512	4,530	4,516
Total	**842,048**	**850,434**	**858,604**

[12] PGE 2014 Annual Report: http://investors.portlandgeneral.com/annuals.cfm

Appendix 3. Research, Development, & Demonstration Projects

SSPC Battery Inverter System (BIS) - Response to Transactive Incentive Signal

The principal goal of the Project was to demonstrate transactive control of SSPC assets; this capability has been demonstrated and in the case of the BIS has operated under this automated control for over a year. With the project's completion at close of 2014, there has been interest in continued testing and development of a regional transactive control system. This is driven by three factors:

1. Efficient control of demand response resources;
2. Improved management of increased penetration of distributed intermittent renewable power from solar and wind generators; and
3. The need to balance on a transactive basis increasingly shorter periods of energy supply and demand. This project proposes to focus expressly on using the SSPC BIS in a transactive control setting that is either regional or within PGE setting.

SSPP 5 MW Load Response to Under-voltage Load Shedding Event

This capability has already been demonstrated as one of the asset functions delivered by PGE in its contractual obligation as part of the Pacific NW Smart Grid Demonstration Project. This effort culminated in the creation of a high reliability zone (HRZ) whereby 1 MW of power was supplied to the feeder under a load shedding scenario. The BIS served as the intermediary to ensure that load could be picked up essentially instantaneously during the shedding event. To complete the high reliability rubric, power supply was then smoothly transferred to a temporary 1 MW diesel power generator that had been attached to the feeder for that purpose.[13] This project is to fine tune the capability and to consider building autonomous control into its operation in anticipation of more energy storage device use on PGE's grid.

[13] Although the Company used a 1 MW diesel generator to perform this function, the SSPP Smart Power Platform has the capability to engage three of PGE's dispatchable standby generators (DSG) in this same role. This ability to tie in the DSG resource via transactive energy control was also demonstrated as part of the Pacific NW Smart Grid demonstration project.

SSPP Real-time Solar Integration Algorithms Utilizing PV Solar Output Signal

This use has already been demonstrated in the following manner – the nearby Kettle Brands potato chip factory graciously allowed PGE to obtain the output signal, via radio from its 114 kW roof-mounted solar PV system. This signal, in combination with the ability to either store or release energy via the BIS is then used to:

1. Reduce peak load on PGE's Rural feeder line and
2. Reduce significantly, the load variation on the feeder to be more in line with the historically-modelled "ideal" load curve.

These outcomes are attractive as they reduce the wear and tear on PGE's substation transformers[14] and at the same time helps integrate the intermittent output that is characteristic of solar PV systems. This project extends this initial demonstration via:

1. Creation of autonomous controls;
2. Underlying studies on the conditions for initiation;
3. Formal documentation of net system benefits/effects; and
4. Potential connection with multiple distributed solar generating systems.

SSPP Frequency Response Test and Deployment

This use has already been demonstrated and done so at the specific request of PGE's Transmission Services Department.[15] In completing this demonstration, a frequency regulation screen was created to allow an operator at the SSPP control room to enter frequency setpoints (high and low) to which the BIS will respond. The operator also has the option to enter the kW of power in response to an event— up to 5,000 kW. Although 5,000 kW is within the capability of the SSPP BIS, the setpoint is generally held to 3,000 kW to ensure that the lithium ion battery is not fully discharged in order to help preserve its expected life. With setpoints in place and response maximum in play, the SSPP BIS can be set to automatically respond to unexpected frequency excursions. This Project will accomplish new autonomous and remote controls for the operation of the SSPP in this mode; later work will fine-tune this work.

[14] For example: Fewer tap changes in response to less voltage and feeder load demand variability

[15] The effort responds to NERC rule BAL-003-1 implemented on April 1, 2015 and supports PGE's ability to respond adequately to an off-normal frequency "event". In PGE's experience – this is especially useful in an under frequency occurrence.

SSPP Adaptive (Dynamic) Conservation Voltage Reduction

This use is similar to static CVR except that with the SSPC's BIS in play it is possible to reduce voltage (and thus power) adaptively over the entire length of the feeder line. This is much more attractive and has the potential to yield higher energy savings to benefit PGE's customers. The approach would be to use existing metering on the Rural Feeder line to develop a feeder voltage profile. Following that, the Oxford substation voltage regulators can be temporarily disabled so that the SSPC inverters can assume the voltage regulation function. The goal is that during times of peak or unexpected demand, voltage can be regulated lower dynamically to reduce the peak power and to more closely match the historical feeder voltage profile. This project will test this notion and if successful will create new autonomous and remote controls so as to offer this capability to PGE System Operations.

Using the SSPP as a Dispatchable Standby Generation Resource

As of this writing, PGE has nearly 100 MW of capacity contracted for use as dispatchable standby generation during periods of extraordinary peak power demand. In this arrangement, all of the consenting facilities deploy backup diesel-powered reciprocating engines that are capable of rapid startup as well as black start use. The BIS has the ability to provide this same service and could add 5 MW to this DSG tally. To affect this would require that control software be replicated to integrate this resource as part of PGE's DSG proprietary GenOnSys control and operations package. Essentially this would reproduce operational of the SSPP BIS to the DSG control center located in Portland Oregon. The early design for the SSPP BIS actually envisioned this remote control option so cost estimates are already available to accomplish this ability should it be desired. This use is entirely feasible. Upon completion it remains to assess its valuation and at what BIS power and energy proportion is rational.

Survey of Distributed Power Generation and Grid-Scale Energy Storage Capability

With decreasing costs for communications and technology coupled with increased societal requirements for renewable power generation – there has been a noticeable move from centralized power to more distributed power generation resources such as solar and wind. The well-known intermittency of these distributed power resources has also spurred a renaissance in grid-scale, energy storage devices to help integrate intermittent renewable power sources. Early demonstrations of grid-connected battery energy storage, of which the lithium ion BIS at PGE's Salem Smart Power Center is an example, are now becoming more frequent. Early uses for these installations include firming and shaping wind and solar generation as well as frequency support. [16] With this background, PGE proposes research that would culminate in an authoritative paper identifying the potential for locating energy storage installations as part of its grid specifically in

[16] Duke Energy's NoTrees facility (advanced lead acid) in Texas and AES Energy Storage's Laurel Ridge (lithium ion) in West Virginia are sizeable battery installations used largely for frequency support in their respective control areas, ERCOT and PJM; whereas Southern California Edison's (SCE) lithium ion battery facility is used to help integrate the wind resource at SCE's Tehachapi Wind Plant in California.

response to high penetration of distributed renewable power. The paper would identify best practices, technical, siting and societal considerations.

Assessing Energy Storage as a Non-Wire Alternative for Transmission & Distribution

It is well known that the Pacific Northwest transmission grid is congested. This is particularly true of east-west electricity movement but also in localized areas. The congestion has grown over the years due to load center growth on the west side of the Cascade Mountains and the proliferation of wind power plants on the east side of the mountains. As the BPA controls 75% of the region's transmission system this is a top of mind concern. Since PGE has a heavy reliance (as do virtually all electric utilities in the region) on the BPA system it is also of import to the Company and its customers. As an example, in southwest Washington and Multnomah County, Oregon where the population has more than doubled there has been no transmission line upgrade or expansion for forty years. This led the BPA in 2011 to propose the "I-5 Corridor Transmission Reinforcement Project" to construct new transmission to help relieve congestion for Cowlitz, Clark and Multnomah Counties. This is roughly an 80 mile run extending from Longview Washington to Troutdale Oregon with construction alternatives. The ability to construct new transmission lines is expensive, daunting to say the least. The advent of large grid-scale energy storage systems of which PGE's Salem Smart Power Center is an example suggests the possibility of a non-wires option to help relieve transmission congestion. PGE proposes a competent and authoritative research paper to set context and to analyze this non-wires possibility in light of recent energy storage advances.

EPRI Information & Communication Technology (ICT, formerly Intelligrid) Program:

When advancing into the smart grid arena it is both apparent and critical that PGE understand ICT requirements. These two EPRI projects address this evolving need. PGE has specific interests in ICT especially for the expected high penetration of distributed energy resources (DER). High DER penetration of renewable power like wind and solar imposes the need for grid response in managing variability. This can be exacerbated by increasing aggregation of multiple types of DER as well as demand response at both customer and utility locations. PGE's participation in Program 161D will give the Company a voice in helping set the standards needed to ensure communication between the variety of grid metering and control devices that are coming into play to provide coherent power variability (and DR) management. A good example is PGE's early work in collaboration with EPRI and water heater manufacturers in helping define interoperability standards for communications socket interface with residential water heaters. PGE expects more of this "intelligent appliance" technology to emerge and or be technologically transferred from research laboratories to commercialization. Program 161A) tracks the rapidly evolving standards and communications technologies that can have major impacts on utility deployments of, for example DR appliance programs. In this event, PGE wishes to ensure that its customers are well educated and prepared with program offerings that can take full advantage of these advances.

Using the SSPC as a Smart Grid Energy Storage Test Facility

Over a 5-year period from 2010-2014, PGE committed substantial financial, material and personnel resources to successfully bring on line the SSPC. The Center is located in Salem Oregon and is fundamentally a 5 MW BIS capable of storing 1.25 MWh of energy. This facility is owned by PGE and is used to test and demonstrate numerous energy storage concepts. PGE's effort required melding a battery supplier with an inverter supplier and ensuring that their respective control and monitoring systems were compatible. After that, a substantial amount of effort was expended to write control and operating software as well as visualizations so that the BIS could be integrated into PGE's grid. Both of these accomplishments were significant and PGE staff gleaned a substantial amount of knowledge in making it happen. PGE staff is now learning how the BIS can function operationally. In achieving this success, there is the obvious opportunity to capitalize on the accumulated knowledge and to build on the success through the performance of additional tests and demonstrations. The SSPC was designed from the outset to be a flexible research, development and demonstration facility. This is manifested in several useful features:

- *Modularity*: The batteries and inverters were arranged in a modular fashion allowing for relatively easy substitution of components by removing one item from the system and replacing with another item.
- *Available Space*: The building was constructed with approximately 1,200 square feet of future space in order to allow for the installation of new equipment.
- *Electrical Access*: Two points of access are available via plug-in cables for the simple addition of 480V 3Ø equipment; additional wiring can be conveniently accommodated via overhead trays.
- *Modifiable Controls*: A substantial data and controls infrastructure was constructed to allow for future programming, automation and data handling, including a network connection to PGE's World Trade Center in Portland, Oregon.
- *Access to Medium Voltage Feeder*: The SSPC is unique in that it provides a fully functional, fully protected interconnection to the utility's 12.47KV grid.
- *Working Amenities*: A visitor viewing room affords the opportunity to host meetings, demonstrations, tours, workshops.
- *Ample physical access*: The SSPC was designed with ample vertical clearance including 14 foot clear height in the building and a roll-up door to move equipment through.

This research project seeks to fine-tune and complete the SSPC as a complete energy storage test facility capable of supporting new applications. Work needs to be done especially

1. in completing previously planned autonomous and remote controls;
2. ensuring full access of the SSPC capabilities (present and future) for control by PGE System Operations;

3. Designing flexible interfaces for Smart Power Platform operations that include more advanced and expanded demand response (DR) program integration involving residential and commercial customers;
4. flexible interfaces for Smart Power Platform operations as it might integrate with aggregated distributed generation resources and
5. expanded interfaces for Smart Power Platform operations as it might integrate with other energy storage options such as thermal or electrical energy storage in residential settings, EV and EV charging infrastructure.

Evaluation of Operating Fuel Cells (FC)

PGE understands that there are two active 5 kW fuel cells resident at Portland Community College (PCC Sylvania Campus) operating in a cogeneration configuration. The two FCs provide power to PCC's Health Technology Building while heat from the system is used to heat the campus swimming pool in the building. These units are made by ClearEdge Power [17] and are phosphoric acid membrane FCs. The units were unveiled originally on September 29, 2011. It has been reported that the units are expected to save $158,000 in energy costs over the 20 year life of the FCs. The total project cost was $162,037 of which PCC cost-shared 50-50 with the USDOE. It was also noted that the US DOE's Pacific Northwest National Laboratory (PNNL) would also monitor PCC's fuel cells during the "next several years to confirm the energy-usage goals." PGE has since learned that the FC stacks were replaced with more a more robust design in 2013.[18]

As PCC is a PGE customer, the Company proposes to also collaborate with PCC Administration, Faculty and Students to assess the performance of these relatively small units.[19] PGE's proposed collaboration would also involve the Power Engineering Department at Portland State University (PSU). The investigation would include assessing, at a minimum:

1. Capacity factor,
2. Efficiency,
3. Routine Maintenance requirements with attendant costs,
4. Recommended Preventive Maintenance,

[17] Unfortunately, ClearEdge Power entered into bankruptcy proceedings in the spring of 2014 and is no longer a going concern; thus, this proposal is contingent on PCC having made sufficient arrangements for proper care and maintenance (e.g. technical know-how, spare parts and the like) in the absence of ClearEdge and its resources – if possible. In August 2014, South Korean conglomerate Doosan Corporation bought the South Windsor, CT assets of ClearEdge and renamed the emerged entity as Doosan Fuel Cell America. Doosan's goal is reportedly to expand manufacturing and marketing of the former ClearEdge phosphoric acid 400 kW fuel cell device as a distributed generation power device with the new moniker of PureCell Model 400 System.

[18] Personal Communication Dr. Tom Prevish, PE who was a ClearEdge VP – telecom 10-29-14 with PGE's W. Lei

[19] On March 25, 2013, PCC's Electronic Engineering Technology Program at the Sylvania Campus announced an elective class: "Introduction to Fuel Cell Systems" to provide complementary curriculum in collaboration with the presence of the ClearEdge FC's.

5. Durability,
6. Cycling flexibility,
7. Overall costs, avoided costs and related soft benefits.

The study is meant to complement any earlier work that may have been performed by PNNL on this system. Failing an agreement with PCC, there is the potential for other options for these relatively new fuel cells.

Hybrid Microgrid Creation with Full Island Capability – Establishing Model Criteria

A unique asset delivered as part of PGE's participation in the Pacific NW Smart Grid Demonstration was to create the ability of the SSPP lithium ion BIS to seamlessly support a fully islanded microgrid. In PGE's original parlance this was referred to as a HRZ. In this scenario, the BIS could support the Rural Feeder line in the event of a frequency excursion induced by loss of energy supply to the Oxford Substation where the Rural Feeder drew its power. Subsequently, the battery could then be relieved of duty by three DSG locations participating in PGE's larger DSG program resident on the same feeder line. These DSG's are diesel powered with more than sufficient capacity to supply both their own needs as well as PGE customers on the feeder.

Since the "next" microgrid project would require substantial planning it would be difficult to identify here, precise costs and benefits. Naturally, some of this can be modelled from PGE's experience with the SSPC. But in the main, these would depend heavily on the proposed use, the location, required components and many other factors. That said, to the extent a new project would involve a substantial BIS of the type deployed by the SSPP it is noted that market costs for batteries are already lower, smart inverters are more capable and of higher capacities; battery and inverter vendors are combining their products as integrated systems. All of this portends substantially lower costs for the next microgrid application on PGE's system – should that be in the cards. To better understand the nature of at least the technical requirements, this project seeks to model the important parameters, limiting conditions and scalability for creation of a microgrid on PGE's system.

Testing and Integration of Smart Inverter Functions

As electric utilities experience increasing penetration of distributed renewable power generation in the form of wind and solar resources at the distribution feeder level, there is heightened awareness for the need to ensure acceptable power quality from both safety and reliability perspectives. The ability to respond quickly and automatically to voltage variations and frequency events helps ensure system reliability. This same ability also allows the grid to proactively respond with demand side controls to limit peak power demand. Higher penetration of distributed power systems also increases the potential for unintentional islanding which poses an electrical safety concern as well as the potential for damage to grid equipment.

Inverters which transform DC to AC power when connected to energy storage devices can and increasingly do offer the capabilities to mitigate many of the concerns noted above. These more advanced inverters have been termed “smart inverters” or “four quadrant inverters” in deference to their flexible capabilities which in turn result from comprehensive programming that allows them to optimize energy storage and release to benefit either the system owner or the host utility or both. It goes without saying that this optimization and added degree of grid protection should help negate the intermittency introduced by wind and solar generation. In doing so, it helps advance the societal demand for incorporating more of these types of renewable power in response to carbon emissions reduction policies through the promotion of renewable energy standards (RPS).

It is also not difficult to foresee compact, defined test protocols to formally assess the positive impacts on PGE’s grid if such intermittent generation resources can also be used to minimize wear and tear on grid equipment. Such a “before and after” comparative test would be straightforward to compose and execute. It could be one of several whereby the “problem of intermittency” is not only defeated through the use energy storage and smart inverters but put to positive use for the benefit of PGE’s grid reliability and durability. PGE in collaboration with Portland State University’s Dr. Bob Bass seeks to compose research-based test protocols to define and document more precisely the benefits of smart inverter use and proliferation at scale on PGE’s grid. Protocol development would take place in 2015 followed by documentation of one to two test cases in 2016.

Joule Bank System (JBS)

This is a continuation of a unique, proprietary project started October 1, 2014 on the design and early prototyping of the Joule Bank System, a new, flexible, highly efficient, residential heating and cooling system based on heat pumps and thermal storage. Extensive collaboration has evolved on this project to ensure arms-length, third-party assessment. Collaborating institutions include Harvey Mudd School of Engineering for thermodynamic assessment and modelling; Portland State University for initial prototype design and development. Because of the thermal storage and utility control features, it is estimated that 90% of peak demand can be eliminated and the energy storage can be “filled” mostly at PGE’s discretion. In 2015, PGE will conclude theoretical and prototype development; in 2016 – it is anticipated that a “production” model will be tested under real-world conditions.

Appendix 4. Conservation Voltage Reduction

OPUC Condition: Report on the findings of the CVR pilot program and the Company's next steps for expansion of the CVR Program.

CVR Cost-Benefit Analysis Report: (Filed with OPUC December 18, 2014, via UM-1657)

Introduction

This report presents the results of a cost-benefit analysis of conservation voltage reduction (CVR) on Portland General Electric's (PGE) distribution system. This analysis was conducted to meet Oregon Public Utility Commission (OPUC) requirements to assess the potential for distribution system energy savings from CVR. PGE is required to "consider conservation voltage reduction (CVR) for inclusion in its best cost/risk portfolio and identify in its action plan steps it will take to achieve any targeted savings" (see OPUC Order No. 10-457 at 22).

This report is organized as follows. In section II, we provide an overview of CVR. In section III, we describe the feasibility study and pilot project that PGE has completed to evaluate the technical potential for energy savings from CVR implementation on PGE's system. In section IV, we explain how the cost-benefit analysis was performed and, for the two substations in the pilot project study, provide estimates of the present values of program costs and benefits. In section V, we discuss extension of the results to possible system-wide implementation. In section VI, we summarize our conclusions.

Overview of CVR

CVR is a means of lowering consumer power demand by operating distribution feeders within the lower portion of the acceptable voltage bandwidth[20]. Consistent with the Northwest Energy Efficiency Alliance's (NEEA) Utility Distribution System Efficiency Initiative Project, this should reduce customers' energy consumption.

PGE's CVR Feasibility Study and Pilot Project

In 2012, PGE conducted a feasibility study to determine the viability of implementing a CVR program without incurring power quality issues (e.g., reducing a customer's voltage below the lower limit of the acceptable voltage bandwidth). Also, the study was performed to quantify the relationship between operating voltage and power demand on PGE's distribution system. Simulation results[21] confirmed the conclusion made by the NEEA: CVR implementation will reduce demand by lowering the amount of energy a customer consumes.

The simulation results led to the funding and implementation of the CVR pilot project at two substations within PGE's service territory: one distribution power transformer in the City of

[20] ANSI Standard C84.1-1989 establishes a "Range A" operating secondary voltage of +/-5% of the voltage base.
[21] See PGE's 2014 Smart Grid Report, Appendix D, published June 1, 2014.

Gresham (i.e., Hogan South WR4) and one distribution power transformer in the City of Beaverton (i.e., Denny WR2). Implementation in Gresham was energized in July 2013; Beaverton in December 2013. Pilot results have validated the conclusions reached based on the feasibility study simulations: at qualified locations, CVR implementation will result in a reduction of customers' energy consumption.

The physical implementation of CVR 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.

Table III-1 shows the results of physical CVR implementation in Gresham and Beaverton.

Table III-1

CVR Pilot Project Customer Energy Reduction

	Hogan South WR4		Denny WR2	
Season	*% kWh : 1% V*[1]	*Total % kWh*[2]	*% kWh : 1% V*[1]	*Total % kWh*[2]
Winter	0.87 : 1	2.17%	0.99 : 1	2.47%
Summer	0.91 : 1	1.37%	0.94 : 1	1.41%

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

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

Measured quantities confirmed that customer demand and energy consumption were reduced as a direct result of CVR implementation. Whether constantly implemented, or used as a peak-shaving method, CVR is more beneficial in the winter due to the higher proportion of resistive loads (e.g., electric furnaces) relative to summer load composition; however, benefits are realized year-round.

CVR Cost-Benefit Analysis

The cost-benefit analysis described in this section of this report is based on data from the completed pilot project study described in section III. As such, the results are based on data from two substations and cannot be immediately extrapolated to PGE's total system; however, the analysis should provide useful guidance as to the relative magnitudes of the costs and benefits of CVR on the PGE system.

The cost-benefit analysis was performed from a "total resource cost" perspective. The analysis considered all direct and quantifiable resource costs. Because the CVR investments are made by the utility, the costs are expressed as revenue requirements. The benefits consist of energy savings that are valued at their avoided costs. The avoided costs are the estimated value of the energy savings at the wholesale market level. The results of the analysis are expressed as the net present value of revenue requirements (NPVRR).

Program Costs

For the cost-benefit analysis of CVR, it is important to determine those costs that are "incremental" to the adoption of CVR. Analysis and design work specific to each distribution power transformer and distribution feeder must be performed. The principal costs incremental to CVR operation include the costs of:

- Engineering design and analysis (performed at the distribution level).
- Updated substation drawings.
- Project management.
- Labor for equipment installation.
- Equipment required for CVR implementation.
- Labor for operating the CVR system over time.
- Maintenance and repair costs for the CVR system over time.

Four pieces of equipment used in CVR are clearly installed to facilitate CVR operations:

- Switched distribution shunt capacitor banks.
- A substation capacitor protection package.
- A load tap changer (LTC) voltage regulation controller.
- A substation communication gateway.

The switched distribution shunt capacitor banks provide reactive power compensation that keeps the power factor at the distribution power transformer within a prescribed range, and provide a voltage boost to customers throughout the feeder. The substation capacitor protection package ensures safe and efficient operation of the switched substation capacitors. The LTC voltage regulation controller maintains a dynamic feeder voltage at the substation to ensure acceptable voltage is delivered to all customers during variable loading conditions. The substation communication gateway ensures a secure connection to the system control center for proper monitoring.

CVR implementation on a feeder also relies on substation equipment already in place. For the purposes of this analysis, we assume that the costs of this pre-existing equipment are not incremental and therefore do not belong in the cost-benefit calculations for the two substations. Implementation of CVR on a system-wide basis will have to be integrated with future investments in PGE's "smart grid." In section V of this report, we provide a brief roadmap of the expected rollout of these investments and explain the relationship of system-wide CVR implementation to these system upgrades.

The details of CVR implementation costs are provided in Attachment A.

Program Benefits

The pilot project study discussed in section III indicated that CVR produces material energy savings.
The level of energy savings resulting from CVR implementation is season dependent. The savings are higher (2.3%) for "winter" months (November through April) and lower (1.4%) for "summer" months (May through October).

Table IV-1 below shows the estimated energy savings by month for the two substations, based on the seasonal percentage factors in Table III-1.

Table IV-1

**CVR Energy Savings at
Hogan South and Denny Substations**

Month	MWh	MWa
January	415	0.56
February	387	0.58
March	363	0.49
April	327	0.45
May	197	0.26
June	190	0.26
July	218	0.29
August	159	0.21
September	148	0.21
October	152	0.20
November	390	0.54
December	421	0.57
Annual	3,367	0.38

The details of the benefit calculations are provided in Attachment A.

Net Program Benefits

The net benefit resulting from CVR implementation at the two substations is calculated by comparing the present values of program costs and benefits. As indicated, program costs are the utility revenue requirements resulting from the incremental costs of CVR implementation. Implicitly, the "CVR Net Present Value" assumes the completion of the three "smart grid" initiatives described in section V. Program benefits are the realized energy savings multiplied by the corresponding per-unit avoided costs.

The results of the cost-benefit analysis are summarized below in Table IV-2. The table reports NPV and the benefit-cost ratio. The table shows that the present value of benefits exceeds the present value of costs by $1,859,073 with a benefit-cost ratio of 3.77.

Table IV-2
CVR Net Present Value
For the Two Pilot Program Substations

Present Value of System Benefits	$2,530,945
Present Value of Costs	$671,872
Net Present Value[1]	$1,859,073
Benefit Cost Ratio	3.77

[1]The Net Present Value analysis was based on a 25-year study period.

CVR's Place in Smart Grid Planning

Due to the manual intervention required to maintain the CVR pilot project, subsequent CVR installation will be unsustainable without first implementing certain "smart grid" initiatives. Chart V-1 below shows the timing of three elements of the Smart Grid program that PGE expects will precede any system-wide CVR implementation:

- **The Communication Network Pilot –** The pilot will analyze the feasibility of utilizing the existing Sensus FlexNet Base Station Multiple Access System (MAS) radio spectrum transceivers as a reliable and secure mode of communication to "smart" devices in the field. Currently, the MAS radio spectrum transceivers are used to gather and deliver Advanced Metering Infrastructure (AMI) information. This pilot will transfer the AMI information to existing Personal Communication Service (PCS) radio spectrum transceivers, in order to allow both datasets (i.e., "smart" device data and AMI data) to coexist. After completion of the pilot, PGE will have selected a communication spectrum to monitor switched distribution shunt capacitor banks associated with dynamic CVR expansion.

- **AMI Voltage Data Bandwidth Expansion –** The bandwidth expansion will upgrade the Sensus Regional Network Interface (RNI) software, and upgrade customer meter encryption and firmware. These upgrades will enable PGE to retrieve all customer voltage data at the meter base in 15 minute intervals. At the time of the CVR pilot project, only a small percentage of customer meter voltage data was able to be obtained at one hour intervals. The resultant addition of all customer meter voltage data, and increased customer voltage resolution, will allow PGE to utilize data analytics software to assist in continuously delivering customers acceptable voltage.

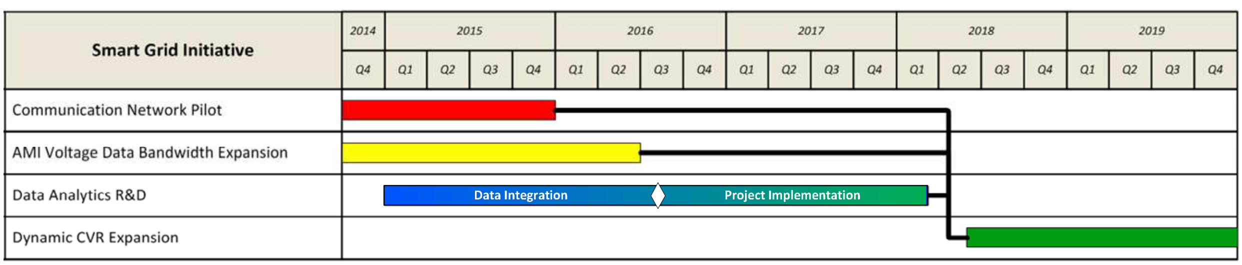
- **Data Analytics Research and Development** – The data analytics research and development will examine which data analytics tool will be utilized to analyze data obtained as the result of "smart grid" implementation, including CVR. Establishing the usage of a proven data analytics tool will provide an interactive user interface where engineers can efficiently observe the status of CVR implementation.

During the "data integration" phase, utility data (e.g., AMI data, asset geospatial information) will be incorporated into the analytics tool. Data reliability, usability, and software functionality will be examined during this phase.

At the conclusion of the "data integration" phase, and the concurrent AMI voltage data bandwidth expansion project, the analytics tool will be examined during the "project implementation" phase. An experimental CVR implementation project will be developed and analyzed using the analytics tool, in order to show "proof of concept" prior to system-wide dynamic CVR expansion.

For example, the analytics tool will leverage the increased customer meter information, acquired as a part of the AMI voltage data bandwidth expansion, by providing the user with real-time customer voltage data. The analytics tool will evaluate the voltage data and set an alarm for those meter voltages that travel outside of the user defined criteria (e.g., outside the acceptable voltage bandwidth). Subsequently, engineers will use the analytics tool to assist in fine tuning CVR control settings.

Chart V-1
<u>Timing of Smart Grid Initiatives with CVR Elements</u>



After completion of the three elements described above, PGE will be able to optimally expand its dynamic CVR program. CVR settings and controls will be managed locally, inside the substation control house, with centralized performance monitoring. Gaining the ability to obtain all customer meter voltage data at a higher resolution, will allow PGE to utilize data analytics software to assist in continuously delivering customers acceptable voltage. Choosing a reliable and secure communication spectrum will allow switched distribution shunt capacitor banks to communicate efficiently and effectively. Establishing the usage of a proven data analytics tool will provide an interactive user interface where engineers can efficiently observe the status of CVR implementation. When necessary, engineers will be able to use this tool to fine tune CVR control settings, in order to obtain the maximum CVR benefit.

Pre-Screening Transformers for CVR Implementation

Initial screening of existing distribution power transformers identified 94 optimal candidates for CVR implementation. These transformers are deemed to be optimal sites for CVR because modern communication equipment (e.g., SCADA) is already installed inside the substation. In addition, these transformers primarily serve residential and commercial load, which reduces the likelihood of customers incurring power quality issues due to the reduced voltage and the existence of industrial machinery. Additional transformers may be deemed CVR candidates upon subsequent screening.

Table V-1 below shows the estimated energy savings by month for the 94 transformers.

Table V-1

**CVR Energy Savings at
94 CVR Candidate Transformers**

Month	MWh	MWa
January	16,677	22
February	15,337	23
March	14,318	19
April	13,019	18
May	7,852	11
June	7,685	11
July	9,372	13
August	9,133	12
September	8,340	12
October	8,185	11
November	14,373	20
December	18,644	25
Annual	142,934	16

Conclusions

This report presents the results of a cost-benefit analysis of a conservation voltage reduction pilot study performed by PGE. This analysis was conducted to meet Oregon Public Utility Commission (OPUC) requirements to assess the potential for distribution system energy savings from CVR. The CVR pilot project study validated the results of a prior feasibility (simulation) study: CVR can produce material energy savings. Based on the pilot study, average percent energy savings realized at two substations were 2.3% for “winter” months and 1.4% for “summer” months.

An analysis of the costs and benefits of CVR implementation demonstrated that CVR was cost-effective for the two substations in the pilot study. The analysis resulted in a benefit-cost ratio of 3.77.

Extrapolation of these results to system-wide implementation is not immediate. PGE has identified a total of 94 transformers on its system that are optimal candidates for system-wide CVR implementation. Expected savings will vary across these transformers.

Due to the manual intervention required to maintain the CVR pilot project, a system-wide rollout of CVR must be coordinated with related "smart grid" investments. These related investments must be in place before CVR can be fully effective. After completion of three elements: the Communication Network Pilot, AMI Voltage Data Bandwidth Expansion, and Data Analytics Research and Development, PGE will be able to optimally expand its dynamic CVR program.

* * * *

Appendix 5. Flex Price^{SM} Critical Peak Pricing

OPUC Condition: Provide an evaluation of the company's CPP Program, any recommended changes to the Program, and next steps for the Program.

PGE Report on Critical Peak Pricing (filed May, 2014)

Introduction

Commission Order No. 09-395 (Docket No. UM 1427) approved PGE's Residential Critical Peak Pricing (CPP) pilot program and adopted certain conditions as part of that approval. These conditions direct PGE to "file reports on the CPP pilot no later than six months after each of the first and second year of the two-year pilot." The reports are to include:

1) Incremental program costs associated with setting-up and conducting the CPP pilot program;
2) Estimation of costs avoided by the Company resulting from usage changes;
3) Analysis of any difference in revenues collected under Schedule 12 as compared with what would have been collected under Schedule 7; and
4) Projected cost/benefits associated with a large scale implementation of a residential CPP program.

The CPP pilot was expected to be online at the end of 2010. PGE, being unable to meet that schedule, petitioned to withdraw its pilot program. The petition was granted, effective September 22, 2010 on the condition that PGE would work with Staff and other interested parties to reformulate the Residential CPP pilot program. On June 7, 2011, the Commission approved PGE's request to reinstitute the Residential CPP pilot program (Advice No. 11-10). PGE successfully implemented the pilot beginning November 2011 through October 2013. PGE submits this report based on the pilot's four operating seasons – Winter 1 (December 2011 through February 2012), Summer 1 (July 2012 through September 2012), Winter 2 (December 2012 through February 2013), and Summer 2 (July 2013 through September 2013).

Third-Party Evaluation

The primary component of the CPP report is provided as confidential Attachment A, which is a detailed third-party evaluation. Attachment A was prepared by DNV GL (formerly KEMA, Inc.) and consists of two aspects: 1) survey-based research, conducted separately for all Winter and Summer seasons; and 2) load shape and load impacts estimation, based on analysis of smart meter and load research sample data, also conducted separately for each of the four seasons. In summary, the DNV GL Report notes that the pilot did realize significant load reductions for the comparable event days.22

DNV GL also evaluated customer satisfaction with the program and identified several significant aspects:

- The primary reason customers participated in the pilot was to save money.
- The pilot experienced attrition during both years of operation, with the number of participants dropping from approximately 1,000 customers to 544 at the end of the program. DNV GL notes that nearly 30% of the total dropouts left the pilot for reasons not related to satisfaction with the program, i.e., they automatically terminated participation when they moved. The primary reasons that customers dropped out of the pilot were:
  - Their electric bill went up after joining program;
  - Difficulty in being able to shift/reduce load; and
  - Didn't see any advantages to continued participation in the program.
- Overall customer satisfaction was approximately 60%.

Attachment A is confidential and subject to the terms and conditions of OAR 860-001-0070.

Other Reporting Requirements

In addition to Attachment A, PGE provides the following information in response to the reporting requirements listed above.

1) *Incremental program costs associated with setting-up and conducting the CPP pilot program*
   PGE's incremental cost to implement the CPP pilot was approximately $652,000. This amount consists of approximately $474,000 for capital and $178,000 for development O&M. In addition, PGE has incurred approximately $290,000 in operating costs, which represent on-going O&M through April 2014. Finally, we have incurred approximately $161,000 for two studies to evaluate the pilot through all of its operating seasons. Attachment B provides additional details of the pilot's costs.

2) *Estimation of costs avoided by the Company resulting from usage changes*
   Because CPP represents a non-firm, capacity resource, we estimate the avoided capacity cost based on the one-hour, maximum kW curtailment (as estimated by DNV GL) times the avoided cost of a least-cost, supply-side resource (on a kW-year basis and discounted by 50% as noted in the Section 4, cost/benefit analysis, below). Based on these assumptions, the avoided capacity cost for the four operating seasons of the CPP pilot is

[22] Based on data available, DNV GL was able to derive results for all eleven winter events but only three of nine summer events. Consequently, the curtailment results cited in this report refer primarily to the winter seasons.

approximately $12,600 (average per event – see Attachment C, "Summary" tab). The avoided energy cost during the CPP event hours totals $253.71 and is based on the kWh curtailments multiplied times the corresponding PowerDex Index price for those hours (details provided in Attachment D).

3) *Analysis of any difference in revenues collected under Schedule 12 as compared with what would have been collected under Schedule 7*

Overall, customers saved $11,886 on Schedule 12 compared to what they would have been billed under standard Schedule 7 prices. Customers that stayed on Schedule 12 for the entire pilot saved $0.86 per month on average. Customers that stayed on Schedule 12 for the first year saved $0.71 per month on average, while customers that continued through the second year saved $1.05 per month on average. A seasonal differentiation is apparent in customer savings for the first year of the pilot. Customers that stayed on Schedule 12 for the entire first winter saved $1.45 per month on average. However, customers that stayed on Schedule 12 for the entire first summer paid an average of $0.19 more per month than they would have on Schedule 7. In the second year, customers that stayed on Schedule 12 saved an average of $1.64 per month for the second winter and $0.39 per month for the second summer. A more detailed summary of the impacts to customer bills may be found in Attachment E.

4) *Projected cost/benefits associated with a large scale implementation of a residential CPP program.*

<u>Costs</u>

PGE provided a detailed estimate of the costs needed to develop a fully scalable CPP program in the first report on the pilot dated March 29, 2013. Because none of the conditions related to that estimate have changed, we did not update that estimate for this report. To repeat, the majority of the costs required to develop a fully scalable CPP program relate to systems PGE is currently preparing for replacement. Until new systems are in place, PGE continues to estimate the cost at approximately $6.1 million, with a potential range of $5 million to $8 million. The $6.1 million estimate consists of the following components:

- $3.4 million in Informational Technology (IT) on PGE's existing customer information system (CIS) which is currently scheduled for replacement by 2017 as part of PGE's Customer Engagement Transformation program (CET).[23] This effort consists of software design, development, and testing and would require approximately 25,700 person-hours to complete. This effort is significant because of the need to configure PGE's current customer information system (CIS) and automate numerous processes for enrollment,

[23] Docket No. UE 262, PGE Exhibit 900, Section III; and Docket No. UE 283, PGE Exhibit 1000, Section IV, provide a description and update of PGE's Customer Engagement Transformation program.

customer communications, event dispatch, meter configuration, etc. that are currently manual during the pilot period.

- $1.0 million for the redesign of the current meter data consolidator (MDC), which is also targeted for replacement in 2017 as part of the CET program. The redesign would be necessary to address the additional data storage and processing capacity needed for a large increase in 15-minute interval data.
- $1.7 million for development O&M to: prepare customer communication documents, develop and deliver program training, develop back-office rules and validation for CIS, develop program management tools, etc.

As PGE continues preparation for a new CIS and MDC, programs such as CPP are being considered and planned for in recognition of the key role pricing options play in our customers' energy future.[24] As noted below, PGE expects the cost to implement a CPP program after the new systems are in place to be significantly lower than with the existing systems.

In addition to the development costs, PGE projects that the CPP program would require the following on-going O&M:

- Years one and two would require approximately $1.2 million to initiate the program, and
- Years three and after would require:
  - Approximately $0.15 million annually to continue to run the program at the assumed low level of customer participation;
  - Approximately $0.5 million annually to continue to run the program at the assumed nominal level of customer participation; and
  - Approximately $1.0 million annually to continue to run the program at the assumed high level of customer participation.

Attachment F provides work papers summarizing the cost components. PGE projects that with existing systems, it would require at least two years to implement a fully-scalable CPP program based on: 1) the cost and complexity of these efforts; 2) the current allocation and availability of IT resources; and 3) the need to better inform customers about CPP pricing in order to achieve adequate participation levels.

Cost/Benefit Analysis

With the costs identified above, PGE used a cost/benefit model previously employed in the UE 189 Docket, which related to PGE's advanced metering infrastructure system (AMI – approved by Commission Order No. 08-245). As part of that proceeding PGE submitted Exhibit 103, the Scoping Plan of Customer and System Benefits. Within that plan and analysis, PGE evaluated the net benefits of a hypothetical, opt-in CPP program with a range of possible participation

[24] This will be discussed in greater detail in PGE's Smart Grid Report that will be filed by June 1, 2014, in accordance with Commission order No. 12-158.

levels. Attachment C of this report provides that same model with updated cost information and benefits as estimated from: 1) the DNV GL study; and 2) the avoided cost of a least-cost, supply-side resource.[25] Because CPP represents a non-firm resource with day-ahead notice, it delivers less benefit than a firm resource that can respond within 10 minutes. Consequently, PGE discounted the avoided capacity cost of the supply-side resource by 50%.

Based on the updated scoping plan, participation levels of 1.5%, 5%, and 10% (by the fifth year of the program) result in a net present value (NPV) cost for CPP over a 20 year program life.[26] The use of a 20-year program life, however, is arguably inappropriate because the installation of a new CIS and MDC in 2017 would establish a new basis on which to associate the CPP benefits. This occurs because the costs estimated above relate to the existing CIS and MDC, which would not carry forward to the new systems.

This means that the cost to implement a CPP program after 2017 would be significantly less than with the current systems. An additional cost, however, relates to the need to better inform customers so they are more receptive to CPP and more likely to participate than at the level realized in the pilot (i.e., approximately 1.4% prior to attrition). This effort will be necessary for any fully scalable program and PGE is currently researching customer education as part of our strategic pricing roadmap. Because PGE does not yet have an estimate of these costs, we have not included them in Attachments C or F.

Although PGE might consider enabling technology in future CPP pilots, we did not include an estimate of enabling technology with this cost/benefit analysis due to:

- The estimated installed cost per programmable communicating thermostat (PCT) is between $400 and $600.
- The low level of interest in PCTs by customers in the current CPP pilot, as identified in the DNV GL study.[27]
- The high level of participation needed to achieve a net present value benefit given the estimated costs for program development absent enabling technology.

Conclusions and Recommendations

PGE believes there are three conclusions to draw from the information in this report:

- Although most load reductions were observed in the winter season, the curtailment results indicate that CPP has potential for peak curtailment in PGE's service territory.

[25] PGE used the least-cost, supply-side resource included in our 2013 IRP.
[26] The NPV estimates are based on the $6.1 million cost estimate for CPP program development. As noted above, this cost could range from $5 million to $8 million with corresponding changes in NPV results.
[27] DNV GL used survey research from program participants and dropouts to identify interest in Smart Thermostats and other home energy display devices.

- The pilot's participation and attrition rates demonstrate that significant customer education will be required before substantial, on-going participation can be expected from PGE's customers in a CPP program.
- PGE's cost/benefit estimates signify that it is not cost-effective to implement a fully-scalable CPP program with PGE's existing CIS and MDC systems.

Furthermore, PGE gained valuable insight to improve future programs:

- The CPP program started near the beginning of the winter season making it more difficult for participants to adjust to a time-of-use rate structure. This likely led to greater attrition during the first winter season and rewarded participants with non-electric heat.
- Adjusting the applicable hours for critical peak events will better target winter peak loads.
- Adjusting the timing of events would address certain requirements for improved baseline calculations for the summer periods.
- Because the program demonstrated TOU effects, future programs should collect the pre-program data in order to quantify the impacts.
- Customers' ability to shift load is key to satisfaction with the program. Simplifying future programs, targeting successful customers, and increasing suggestions are critical to load shedding and overall satisfaction.

This will allow additional results to inform our decisions for future CPP-related activities. Among these activities, PGE plans to:

- Identify CPP and time-of-use requirements for new systems and programs.
- Continue to monitor demand response programs and results from other utilities.
- Develop an education program to better inform customers regarding the purpose of, and how to effectively participate in, dynamic pricing options and demand-response programs.
- Evaluate and propose additional pilot alternatives that could help PGE develop a CPP program.
- Continue to implement PGE's CET program in which we will replace the current CIS and MDC. This will create the platforms on which a more cost-effective, fully scalable CPP program can be developed along with the other benefits discussed in PGE Exhibit 1000 in Docket No. UE 283.

In the near term, PGE will continue to work with the OPUC Staff and other interested parties to determine the next appropriate steps regarding CPP. In this regard, we plan to consider all dynamic pricing options and their costs/benefits in order to implement the programs that make the most sense for customers.

* * * *

The following attachments were included along with this report in the original May, 2014 filing via CD:

- Attachment A – DNV GL Pilot Evaluation Report (2011-2013)
  [Confidential and subject to the terms and conditions of OAR 860-001-0070]
- Attachment B – Incremental Pilot Costs
- Attachment C – Estimated Cost/Benefit Analysis for Fully Scalable CPP Program
- Attachment D – Estimated Impact of CPP Pilot
- Attachment E – Difference in Revenues Schedule 12 vs. Schedule

Appendix 6. Synchrophasor Deployment

OPUC Condition: PGE should report to the Commission on the company's evaluation of deployment of more synchrophasors in its system.

Executive Summary

The X-Phase Project is the integration of Phasor Measurement Units (PMUs) on PGE's Transmission and Distribution system to enhance situational awareness affecting the reliability, efficiency and performance of PGE's transmission system; solving and preventing problems before they happen; allowing for post-event analysis; enhancing situational awareness. Time-synchronized measurements, known as synchrophasors, enable operators to directly observe system state, display this information and create better solutions for local and wide-area control, protection and monitoring.

Modern power system grid monitoring uses data from remote terminal units (RTUs), protective relays, and transducers to provide information to system operators. This information is vital for the operation of the power system on a daily basis and under system contingencies. However, the mechanism used to retrieve data from the devices is asynchronous and relatively slow. The asynchronous nature of the data does not provide accurate angle difference information from two or more nodes on the network. Additionally, the low volume of retrieved data is too slow to capture many short-duration disturbances on the grid.

PMUs sample voltage and current very fast (30 to 60 times a second) and accurately GPS time-stamp each sample. This technology is used to provide high-speed, synchronous real-time information that is not available from legacy SCADA systems, which typically samples once every 4 to 5 seconds without phase angle and time stamp verification.

The X-Phase Project will use PMU technology to deliver real-time data that enhance system operators' situational awareness. A synchrophasor system, with wide deployment of PMUs, 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. Synchrophasor measurements can also be used to improve component and system models for both on-line and off-line network analysis for assessing system security, adequacy to withstand expected contingencies and perform event analysis.

The long-term goal of the X-Phase Project is to develop a wide-area network of PMUs encompassing all PGE Transmission Substations, which will be developed thru a multi-year, multi-phase roll out. PMUs are built-in to most protective relaying equipment and the PMUs will be in the network; the X-Phase Project aims to connect them and utilize the data.

In 2015, the project will include new IT infrastructure, which amounts to $320,518 to install a server and data storage on the Energy Network. The remaining costs include equipment and labor that will upgrade five substations, which is estimated to be $98,196.

The total loaded cost for 2015 is $418,714.

Background

The following are areas in which PGE can improve transmission system situational awareness with this synchrophasor initiative.

- PGE's legacy SCADA system is limited in capability because it does not include phase angle and time synchronized measurements, which are taken every 1-2 cycles. A SCADA system scans its remote terminal units every five seconds. The quantities being measured via SCADA are adequate for steady-state localized control, but do not provide insight into interaction of the broader transmission system. Synchrophasors provide accurate, time-aligned measurements in different locations and are useful to neighboring transmission operators in the WECC. Such data can provide a comprehensive, real-time picture of transmission system operations across an entire transmission region or interconnection.
- There is a great deal of value in synchronizing these measurements and controls. The results of synchrophasor processing translate into controlled actions that are issued in real-time. When we synchronize voltage and current measurements, and collect measurements taken at the same instant, we have directly measured the dynamic state of the power system. Direct and frequent measurement of the state makes protection and control of the power system more efficient, safer and reliable.
- PGE also has known interconnection issues with PacifiCorp and other critical interties. With two asynchronous systems merging during interconnection, an increasing phase angle difference can be a serious problem when the deviation gets large enough to cause arcing or out-of-step conditions. These are potential safety concerns, specifically PGE's Hayden Island interconnection. Synchrophasors would accurately phase and provide critical measurements to safely switch between these systems.
- PGE protection routinely encounters false breaker trips which result in unnecessary disturbances to the transmission system. These disturbances not only affect transmission customers, but can affect customer equipment in the distribution network. The use of synchrophasors can improve protection schemes and aid in design settings to help mitigate false trips.
- Voltage sags and momentary interruptions from false trips are two of the most important power quality issues affecting industrial customers. Problems and reliability improvements in the bulk transmission system (reduced frequency, duration and extent of outages, and their impacts on transmission availability; and faster restoration of outages) provide a measurable cost savings to PGE. The X-Phase Project can provide early,

improved detection of evolving grid problems and provide operators with the ability to implement real-time mitigation measures.

Transmission availability and the opportunity to optimize power delivery to Transmission Customers is a source of revenue to PGE. So without the X-Phase project, PGE isn't realizing actual gains from optimizing system parameters; increasing productivity and reducing costs. Thereby providing more precise determination of system limits, minimize false trips, higher resolution of voltages, current and frequency, improved transmission pathway with congestion management and power flow out of generation facilities enabling operations to be closer to those limits.

Project Overview

This multiyear, multiphase project will initially establish a base wide-area network with six critical substations. This includes: Bethel, Gresham, West Portland, Rivergate and Trojan. In addition to these five substations, Rosemont substation will be commissioned using 2014 R&D funding. With this base network established, additional substations will be upgraded to expand synchrophasor capabilities and build a wide-area network of PGE's system.

There are an estimated 120 people in engineering and operations that will directly utilize and benefit from the X-Phase Project. It will foster a new opportunity to learn and grow among multiple departments and allow improved coordination among SCC, protection, and T&D operations.

In addition to the value added to protection, control and monitoring, the X-Phase Project will allow PGE to be a more efficient and reliable player in the Western Energy Markets. The anticipated growth of variable renewable generation, such as solar and wind power, in the West has raised concerns about how system operators will maintain balance between electricity production and demand in the Western Interconnection and especially in its smaller balancing authority areas. Electric utilities are therefore considering the adoption of a large-scale energy imbalance market to address fluctuations in electricity generation and load. In an energy imbalance market, the variability of electricity generation and load is aggregated over multiple balancing authority areas and utility territories.

In the proposed Western energy imbalance market, balancing authority areas would pool their variable and conventional generation resources to improve operational efficiency over a wider area. This sub-hourly, real-time energy market would provide centralized, automated, and region-wide generation dispatch. By increasing the temporal and geographic footprint of the total balancing authority area, the market could moderate the variability of renewable generation resources and electricity demand. By deploying the X-Phase Project system, PGE we will be better positioned to meet these anticipated demands.

Scope of Work

This project includes a base requirement for 10 TBs of data storage. It also requires the installation of Phasor Data Concentrators (PDCs) in each substation to process phasor data from PMUs at each bus voltage level and communications from transmission substations to the Remote Access Server (3WTC 3rd Floor). Data will be stored and processed through master visualization software. Included in this project are the following:

- The addition of (10Tb) worth of storage with the Remote Access Server - Energy Network Server, which will store up to three years' worth of data for expanded capability up to 50 PMUs. This three year requirement for storing event data aligns with NERC/WECC audit schedules.
- Substations included in scope: Bethel, Gresham, Rivergate, Trojan, West Portland
- T1-Lines (~1.5Mbps) from substations to remote access server. (*Not part of this funding request already planned* to be implemented by Communications Engineering.
- Installation of (5) Phasor Data Concentrators (PDC), one in each transmission substation.
- Visualization software.
- Team software for on/off-line engineering analysis that will allow engineers and operators to benefit from this project.

I. Cost Estimate

Item	2015 Est. Cost
Bethel Substation	$ 15,183.00
Gresham Substation	$ 15,103.00
Rivergate Substation	$ 15,089.00
Trojan Substation	$ 15,305.00
West Portland Substation	$ 37,516.00
(IT) Software O&M	$ 29,673.00
(IT) Software Capital	$ 290,845.00
	$ 418,714.00

Conclusion

T&D Planning recommends implementing the X-Phase Project to integrate PMUs on PGE's Transmission and Distribution system. This will enhance situational awareness affecting the reliability, efficiency and performance of PGE's transmission system and provide engineers with data and tools for post-event analysis. The total cost for the project is $418K for the required IT infrastructure and five initial substations.

The X-Phase Project will prove its value for operations and planning. Providing PGE the opportunity to elevate its T&D capabilities and improve its' position in the WECC as regional operator.

Synchrophasor technology is growing rapidly, becoming commonplace and integrated in many control rooms across the nation. The X-Phase project will establish a new high-reliability platform for protection, control and monitoring technologies and will allow PGE to be better positioned to incorporate advanced automation and control technology.

* * * *

Appendix 7. Salem Smart Power Project

OPUC Condition: Share lesson learned from the project and how results will be documented, shared, built upon going forward, and evaluated for cost effectiveness.

Acknowledgments
PGE's Salem Smart Power Project team is pleased to acknowledge the work of its internal and external partners and suppliers on this project. We especially acknowledge the Project staff at Battelle located in Richland, WA for their guidance and support in technical and administrative matters. The team also gratefully acknowledges the many PGE departments that helped bring this 5-year effort to fruition. This material is based upon work supported by the U.S. Department of Energy under Award Number DE-OE0000190.

Salem Smart Power Project Background

PGE has implemented the Salem Smart Power Project (SSPP) delivering five assets that are funded as part of the US DOE's 5-year, $178 million Pacific NW Smart Grid Demonstration Project. The SSPP effort expended $25 million of which 50% of the cost was covered by US DOE stimulus funding. The remaining 50% was 50-50 cost shared between PGE and its principal vendors. PGE's overall cost was $6.5 million and yielded the Salem Smart Power Center which showcases a 5 MW, 1.25 MW-hr lithium ion battery-inverter system. The facility is located at PGE's Oxford substation and is grid-tied via the Rural Feeder line. PGE served as a contractor to Battelle which in turn was the primary to the US DOE.

SSPP assets have demonstrated responsiveness to transactive control as well as the ability to fully island as a microgrid in collaboration with three PGE dispatchable standby generator partner sites. Ten additional use and valuation cases have been identified of which three have been demonstrated to date. Recent demonstrations include short-term, fast up and down frequency support and using the battery plus solar PV signal from Kettle Brands to firm and shape the feeder load.

Salem Smart Power Project Lessons Learned

As an online, operating facility the SSPP overcame significant issues covering a spectrum of operational and cultural landscapes. These included administrative, financial and technical concerns that were defeated through intense scrutiny, team problem solving and thoughtful resource allocation by the project manager, business sponsor and PGE senior management. The goal of this retrospective report is -- in the clear light of hindsight -- to highlight both positives and negatives so that PGE in future, similar efforts will repeat the former and avoid the latter.

Key learnings from this project include:

- *Thoroughly vet vendors' capabilities and financial wherewithal* **--** Smart grid technology is a growing industry, full of emerging companies. Making sure these companies are well-capitalized will help ensure the financial success of the project. If possible consider insurance as a backup.

- *Leverage outside resources to reduce risk* -- The federal stimulus money from the Pacific Northwest Smart Grid Demonstration Project helped make this project possible. Stimulus money helped to reduce the amount of financial risk for PGE during the startup for this project.

- *Assemble a strong, adaptable engineering and project management team* -- The PGE SSPP team was able to lead the project over many different hurdles. As the experts on this topic, the team not only had to work on the managerial and technical aspects, but also be able to communicate well with everyone in the company.

- *Do lots of testing* -- As there was the potential to impact both commercial and residential customers, perform and document much testing to ensure the new system(s) will not negatively impact customers and yet remain robust and reliable.

- *Take plenty of precautions* -- Area emergency responders, such as fire responders, were trained and knew exactly what was in the Salem Smart Center Facility. Extraordinary safety and fire detection/suppression into this first facility were emplaced to ensure its acceptability in the community and as a functioning feature of PGE's grid.

- *Understand the impact of the rules for a new game* -- PGE entered into a contractual arrangement with the company serving in a contractor role. The rules allowed for multi-year budget moves including taking a deficit budget position on an annualized basis (funds recovery occurring in the following year). The contractor role, hard deadlines and tolerance for deficit budgets were unusual and counter to normal administrative and management practices in the electrical utility industry.

Salem Smart Power Project Use and Valuation Tests

Executive Summary

The Pacific NW Smart Grid Demonstration is slated for completion by close of January 2015. PGE and all sub-contract recipients have been advised by Battelle (primary contractor) and the US DOE to begin a series of project close out processes. This paper discusses PGE's responses to this guidance with special focus on the potential or likely future uses of the installed physical assets. As PGE's developed assets were subsidized by substantial federal funds, PGE would like to be clear about its intentions for continued and planful use of these assets in a manner that is consistent with the original purpose of the Pacific NW Smart Grid Demonstration.

The list below identifies use and valuation cases for the SSPP BIS as of this writing.

1. Respond to transactive node/transactive signal
2. 400 kW of demand response benefit
3. 1.3 MWh of energy shift from on-peak costs to off-peak costs
4. 2 to 4 MW of real-time voltage & frequency for system OPS
5. kVAr support and control on the distribution feeder
6. ≈ 1.2 MWh of off-peak ability to absorb excess wind power
7. 5 MW load response to under-voltage load shedding event
8. Real-time solar integration algorithms utilizing Kettle Brands' solar output signal
9. Up/Down frequency regulation
10. Distribution automation using advanced, intelligent relays
11. Adaptive Conservation Voltage Reduction (ACVR)
12. Use as a dispatchable standby generation (DSG) resource

Use and valuation tests that remain unexplored are being submitted for PGE R&D funding consideration for 2015 or 2016 depending on funding and staffing constraints. The SSPC Advisory Committee will help assess the highest and best programmatic use of the facility and make recommendations to PGE Executive Management most likely in 2015.

Use Cases Nos. 1, 7, 8 and 9 are either complete or substantially so. Several cases require relatively light effort and cost to complete (e.g., Use Cases Nos. 2, 3, 4, 5). Use Case number 6 -- using the BIS to absorb off-peak excess wind energy -- will be performed as part of a 2015 PGE funded capital project. This leaves three test cases that have relatively substantial programmatic impact and associated costs.

Use Case #10 – Distribution Automation using advanced, intelligent relays
Use Case #11 – Adaptive Conservation Voltage Reduction (ACVR)
Use Case #12 – Incorporating the SSPC BIS as part of PGE's DSG Program

For the purposes of this report, it is recommended that Adaptive Conservation Voltage Reduction be given the highest priority for completion inasmuch as the Oregon Public Utility Commission has strong interests in conservation voltage reduction and the availability of the SSPC BIS allows PGE to explore a natural extension of that capability.

PGE's Delivered Contractual Assets – Local Utility Level

PGE's Salem Smart Power Project delivered five contractually-required assets: (1) Residential demand response (DR); (2) Commercial DR; (3) Commercial dispatchable standby generation (DSG) – Grid Connected; (4) Battery Storage – Grid Connected; (5) Distributed Switching and Commercial Microgrid. These assets were integrated via PGE's Smart Power Platform. They were declared as used and useful capitalized utility assets as of August 30, 2013. From that time to the present writing, all five of PGE's assets have been demonstrated to respond to the Transactive incentive signal (TIS). Of the five assets, routine response to the transactive incentive signal is provided by the SSPP Battery Inverter system while grid connected. This will continue until close of the Project data collection stage (Phase 3) which is targeted for the end of August 2014.[28]

Pacific NW Smart Grid Regional Demonstration Project

The primary objectives of the Pacific Northwest Smart Grid Demonstration project are to:

- Create the foundation of a sustainable regional smart grid that continues to grow following the completion of this demonstration project.
- Develop and validate an interoperable communication and control infrastructure using incentive signals to: coordinate a broad range of customer and utility assets, including demand response, distributed generation and storage, and distribution automation; engage multiple types of assets across a broad, five-state region; and reach from generation through customer delivery.
- Measure and validate smart grid costs and benefits for customers, utilities, regulators, and the nation, thereby laying the foundation of business cases for future smart grid investments.
- Contribute to the development of standards and transactive control methodologies for a secure, scalable, interoperable smart grid for regulated and non-regulated utility environments across the nation.
- Apply smart grid capabilities to support the integration of a rapidly expanding portfolio of renewable resources in the region.

[28] For more detail on the types of assets that are responsive to transactive control see: https://www.bpa.gov/energy/n/Utilities_Sharing_EE/Utility_Summit/Workshop2013/SmartGridinthePNW.pdf

U.S. Department of Energy
At the national level, the U.S. Department of Energy (US DOE) has elaborated its vision for the evolution of energy storage capabilities as part of the U. S. electrical grid. The three goals below are quoted directly from its 2013 assessment summary report on the state of the technology and its uses.[29]

1. Energy storage should be a broadly deployable asset for enhancing renewable penetration – specifically to enable storage deployment at high levels of new renewable generation.

2. Energy storage should be available to industry and regulators as an effective option to resolve issues of grid resiliency and reliability.

3. Energy storage should be a well-accepted contributor to realization of smart-grid benefits – specifically enabling confident deployment of electric transportation and optimal utilization of demand-side assets.

Governance
Due to the novel and unique nature of the SSPP and its assets, PGE has instituted a multi-disciplinary governance structure to assess how these assets might be used in the future – especially -- (1) in a manner that is consistent with the original funded purpose and (2) to optimize its value to PGE customers as a grid-tied asset.

Two levels of decision and advisory governance are established. The first involves a high level committee that includes PGE officers; this committee addresses policy and program direction around PGE's overall Smarter Grid efforts. The second committee draws from many disciplines within PGE; includes senior managers and technical staff and focuses exclusively on the future uses of the SSPP assets – especially the BIS.

Discussion of Proposed Use and Valuation Test Cases Specific to the SSPC
Each proposed use and valuation test case specific to the SSPC is discussed in more detail below. In each case there is some attractive quality that makes the case interesting if not compelling. Regardless of whether the use case "makes the cut" there is no question that important learnings will occur to further PGE's experience with the unique capabilities of the SSPP battery-inverter system and these are valuable in their own right.
Proportional use of either power or energy or both are still speculative at present. This will depend on later optimization of the Battery Inverter System – especially if concurrent uses are contemplated. That said, it is also entirely possible that the BIS may have "one use" as its best and highest value application.

[29] See: U.S. Department of Energy, December 2013, *Grid Energy Storage*, 67 pages; Available at: http://energy.gov/sites/prod/files/2013/12/f5/Grid%20Energy%20Storage%20December%202013.pdf

1. *Battery Inverter System - Response to Transactive Incentive Signal*
   This capability has already been demonstrated. As discussed earlier, PGE delivered five assets in its role as a sub-contractor to Battelle as part of the Pacific NW Smart Grid Demonstration Project. All five assets were demonstrated to be responsive to the transactive incentive signal. The BIS in particular, has been responsive for the better part of a year and per Project guidance will successfully close this portion of the demonstration at the end of August 2014.

2. *400 kW of Demand Response Benefit (DR)*
   Two of the assets demonstrated as responsive to the transactive incentive signal included demand responsiveness involving: (1) twenty radio-controlled residential water heaters and (2) 51 commercial entities that volunteered to participate. Control for these assets involved automated interaction with PGE's Smart Power software platform and a "human in the loop" rubric to ensure a smooth experience for participating PGE customers. To involve the BIS in a demand response role is straightforward. The only technical hurdle is how to best receive the demand response signal. If a simple "manual" response is adequate, no further effort would be needed. If an automated DR is desired, this would incur a small expense to produce a software control program. This use is entirely feasible. Upon completion it remains to assess its valuation and at what BIS power proportion is rational.

3. *1.3 MWh of Energy Shift from on-Peak Costs to Off-Peak Costs*
   As part of the Pacific NW Smart Grid Demonstration, this control already exists and for largely this purpose. At the conclusion of the Demonstration and in the likely event that a regional transactive control center no longer exists to carry the demonstration further – then control would be simplified to target just a peak shifting function. This would incur a small cost to create (or possibly modify) a much simplified, automated control rubric. This use is entirely feasible. Upon completion it remains to assess its valuation and at what BIS energy proportion is rational.

4. *2 to 4 MW of Real-time Voltage Support for System Operations*
   This use case does require more operational definition; at a minimum or in the simplest case, the present SSPP controls might be replicated for manual System Operations control. This could also be automated so that voltage control would respond without operator intervention. This use is entirely feasible. Upon completion it remains to assess its valuation and at what BIS energy proportion is rational.

5. *kVAr Support and control on the Distribution Feeder*
   The SSPP BIS can already perform a kVAr support function albeit only under manual control as of this writing. To automate this function requires the creation and installation of basic

control software. This use is entirely feasible. Upon completion it remains to assess its valuation and at what BIS energy proportion is rational.

6. *≈1.2 MWh of Off-Peak ability to Absorb Excess Wind Power*
   Using the BIS to absorb excess wind generated energy would require obtaining an appropriate signal from a wind generation facility. In 2013 this feature was conceived and incorporated as part of a PGE capital job that involved the test emplacement of an advanced LIDAR anemometry instrument atop a wind turbine at PGE's Biglow Canyon Wind farm. This capital job was approved for initiation in 2014. PGE's Scott Mara in the PSES Department is responsible for this capital job. This use is entirely feasible. Upon completion it remains to assess its valuation and at what BIS energy proportion is rational.

7. *5 MW Load Response to Under-voltage Load Shedding Event*
   This capability has already been demonstrated as one of the asset functions delivered by PGE in its contractual obligation as part of the Pacific NW Smart Grid Demonstration Project. This effort culminated in the creation of a high reliability zone (HRZ) whereby 1 MW of power was supplied to the feeder under a load shedding scenario. The BIS served as the intermediary to ensure that load could be picked up essentially instantaneously during the shedding event. To complete the high reliability rubric, power supply was then smoothly transferred to a temporary 1 MW diesel power generator that had been attached to the feeder for that purpose. [30]

8. *Real-time Solar Integration Algorithms Utilizing Kettle Brands' PV Solar Output Signal*
   This use has already been demonstrated in the following manner – the nearby Kettle Brands potato chip factory graciously allowed PGE to obtain the output signal, via radio from its 114 kW roof-mounted solar photovoltaic (PV) system. This signal, in combination with the ability to either store or release energy via the BIS is then used to: (1) Reduce peak load on PGE's Rural feeder line and (2) Reduce significantly, the load variation on the feeder to be more in line with the historically-modelled "ideal" load curve. These outcomes are attractive as they reduce the wear and tear on PGE's substation transformers[31] and at the same time helps integrate the intermittent output that is characteristic of solar PV systems.

[30] Although we used a 1 MW diesel generator to perform this function, the SSPP Smart Power Platform has the capability to engage three of PGE's dispatchable standby generators (DSG) in this same role. This ability to tie in the DSG resource via transactive energy control was also demonstrated as part of the Pacific NW Smart Grid demonstration project.

[31] For example: Fewer tap changes in response to less voltage and feeder load demand variability

9. *Frequency Response Test and Deployment*
This use has already been demonstrated and done so at the specific request of PGE's Transmission Services Department.[32] In completing this demonstration, a frequency regulation screen was created to allow an operator at the SSPP control room to enter frequency setpoints (high and low) to which the BIS will respond. The operator also has the option to enter the kW of power in response to an event— up to 5,000 kW.[33] With setpoints in place and response maximum in play, the SSPP BIS can be set to automatically respond to unexpected frequency excursions.

10. *Distribution Automation Using Advanced, Intelligent Switches*
Four advanced Intellirupter Switches made by S&C Corporation were installed by PGE as one of the five asset deliverables for the Pacific NW Smart Grid Demonstration project. These relays are strategically placed on the Rural Feeder to allow automated switching control in the event of a fault in some portion of the line. These relays routinely and rapidly query the line with time-stamped pulses to ensure continuity and to quickly localize a fault. These switches have been tested and shown to be responsive to transactive energy control. Nonetheless, there is much more that should be explored to fully utilize their capabilities especially in fault isolation where instead of the entire feeder being rendered off line in response to a fault, the use of these switches would isolate only the affected portion of the line. To press forward with this innovation, an internal PGE R&D project has been scoped to further automate and incorporate the use of these switches on PGE's grid. It is likely that such testing will occur in 2015.

11. *Adaptive (Dynamic) Conservation Voltage Reduction*
This use is similar to static conservation voltage reduction (CVR) except that with the BIS in play it is possible to reduce voltage (and thus power) adaptively over the entire length of the feeder line. This is much more attractive and has the potential to yield higher energy savings to benefit PGE's customers. The approach would be to use existing metering on the Rural Feeder to develop a feeder voltage profile. Following that, the Oxford substation voltage regulators can be temporarily disabled so that the SSPP inverters can assume the voltage regulation function. The goal is that during times of peak or unexpected demand, voltage can be regulated lower dynamically to reduce the peak power and to more closely match the historical feeder voltage profile.[34]

[32] The effort is in anticipation of a rapidly developing NERC rule on the need to respond adequately to an off-normal frequency "event". In PGE's experience – this is especially useful in an under frequency occurrence.

[33] Although 5,000 kW is within the capability of the SSPP battery inverter system, the setpoint is generally held to 3,000 kW to ensure that the lithium ion battery is not fully discharged in order to help preserve its expected life.

[34] Explicitly: $P = V^2 / R$; Where:
P = Power
V = Voltage
R = Resistance

12. *Use as a Dispatchable Standby Generation Resource*
As of this writing, PGE has nearly 100 MW of capacity contracted for use as dispatchable standby generation during periods of extraordinary peak power demand. In this arrangement, all of the consenting facilities deploy backup diesel-powered reciprocating engines that are capable of rapid startup as well as black start use. The BIS has the ability to provide this same *non-spinning reserve* service and could add 5 MW to this DSG tally. To affect this would require that control software be replicated to integrate this resource as part of PGE's DSG proprietary GenOnSys control and operations package. Essentially this would reproduce operational control of the SSPP BIS to the DSG control center located at the World Trade Center in Portland Oregon. The early design for the SSPP BIS actually envisioned this remote control option so cost estimates are already available to accomplish this should it be desired. This use is entirely feasible. Upon completion it remains to assess its valuation and at what BIS power and energy proportion is rational.

Operation, Maintenance, Program

Routine custodial maintenance (cleaning, landscape upkeep, etc.) of the SSPC is budgeted annually by PGE Facilities Management. The SSPC is monitored 24/7 for security via closed circuit cameras from the WTC Security center. Routine inspection of fire protection equipment and monitoring systems are institutionalized in PGE's safety department. A SSPC Operations Manual complete with a prominent section on Safety has been developed and tested for operator use and training. A programmatic transition plan for the SSPC battery inverter system asset is currently under development and is being discussed with potential stakeholders.

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i.e. Power can be reduced on the resistive component of the load proportional to the square of the voltage

Appendix 8. Smart Inverters

OPUC Condition: Document the use of smart inverters in its service area and report on future initiatives.

Through efforts of SEGIS grants, PGE owns or operates 19 smart inverters at 12 PV solar installations totaling 5.3 MW (DC) of nameplate capacity. PGE commissioned a white paper in 2013 in collaboration with Portland State University, titled *Smart Inverters for Photovoltaic Resource Integration, Portland General Electric*.

The inverters have demonstrated the ability to be controlled via a central control system to:

- remotely connect/disconnect systems
- adjust power factor
- provide curtailment control
- adjust ramp-up rate

Note: 3 of the 12 PV locations and 4of the 19 smart inverters are only capable of remote disconnect/reconnect

In addition to PV use cases, the 20 smart inverters at SSPC enable the functionality such as transactional control and frequency regulation (see pg. 18, 82).

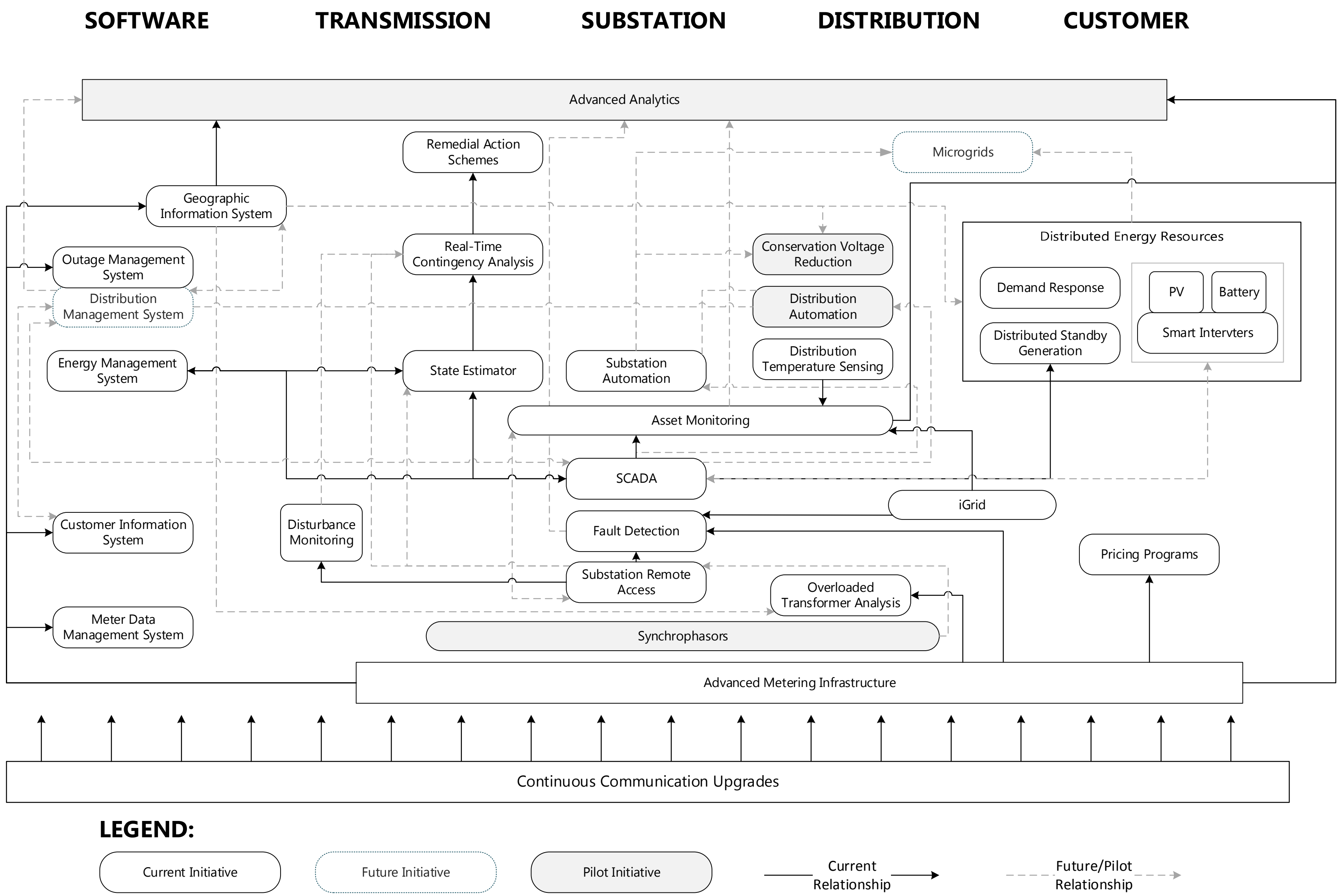
In order for PGE to realize the benefits of smart inverters at a utility scale, a wider scale of enablement and adoption of smart inverter technology is required (on the order of $\geq$ 20 MW). Because current industry standards (UL, IEEE, etc.) do not allow wide-scale deployment of smart inverters, no customer owned/operated PV systems have utility-enabled smart meters.

PGE's planned efforts around smart inverters are to encourage broader adoption of the technology:

- Continued RD&D on how to maximize smart inverter benefits
- Advocate for widespread adoption of smart inverter[35]
- Anticipated involvement in OPUC workshops on smart inverters

[35] PGE is supportive of Western Electric Industry Leaders' (WEIL) proposed efforts to encourage widespread adoption of smart inverters that promote renewable integration.

Appendix 9. Visualization of T&D Smart Grid Initiatives



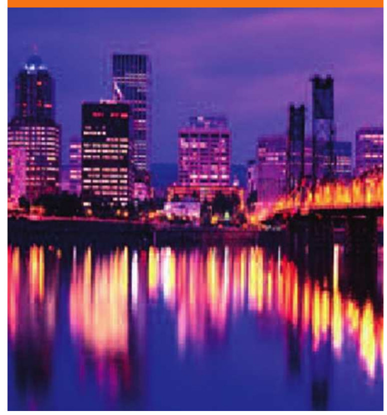
Appendix 10. Smart Thermostats & Time of Use Pricing

OPUC Condition: PGE should report on its evaluation of whether to actively promote voluntary residential and small commercial time of use pricing programs.

OPUC Condition: PGE should provide information on PGE's Smart HVAC & Smart Thermostats pilot, including what will be tested and how success will be measured.

PGE presented "Pricing & Residential Demand Response Pilots" in a workshop to OPUC on March 4, 2015. The presentation addressed both OPUC conditions and is attached to this report.

Pricing & Residential Demand Response Pilots



Deferral follow-up workshop

Date: March 4, 2015

Presenter:
Business Model and Product Development

Portland General Electric

Agenda

- Objective of pursuing these pilots
- Program results from other utilities
- Proposed pilots structure and approach
- Timeline

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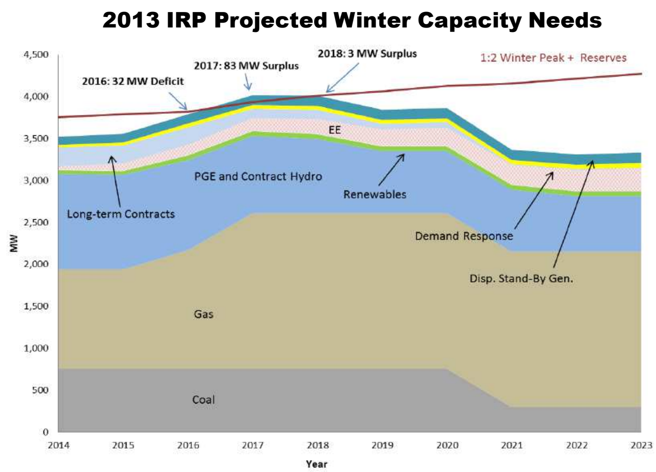
Looking Forward: PGE's Capacity Gap



- 2013 IRP calls for 45 MW of customer enabled capacity
- Residential customers could contribute a 1% - 3% reduction of peak from pricing and direct load control (DLC) programs*

* Brattle Groups, *PGE 2012 Demand Response Potential Study*

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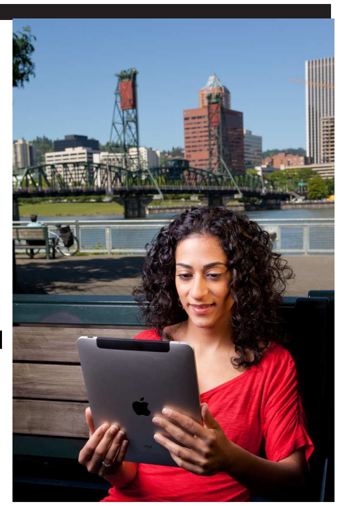
Objectives & Value of the Pilots

- Response to stakeholder feedback in IRP & Smart Grid Report dockets requesting pricing and residential direct load control (DLC)
- Finding system benefit from customers managing their load
- Make participation easy by offering customers programs that match their lifestyle
- Educate customers on peak demand and reward them for being part of the solution
- Identify successful tactics for achieving our shared objectives before rolling out at full scale.



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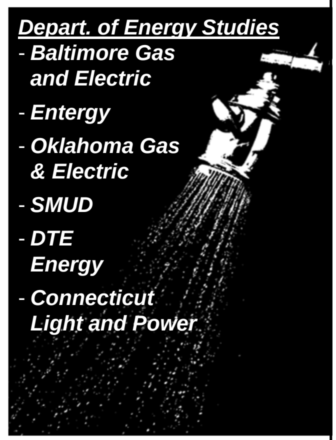
What Other Utilities Have Found

- Dynamic pricing programs are effective in changing usage behavior
- While Critical Peak Pricing (CPP) and Peak Time Rebate (PTR) achieve comparable peak reductions, PTR results in higher customer participation and retention
- DLC thermostats deliver solid peaks savings
- Program design is critical to program success
- One size doesn't fit all; Utilities needed to test a few concepts finding the design that works for a utility's customer base



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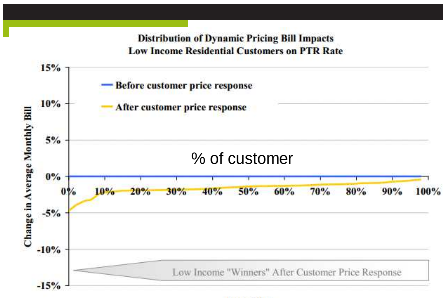
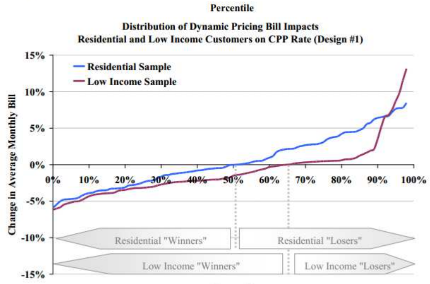
Dynamic Pricing Impacts on low income





- PTR always positively impacted low income customer bills*
- Studies show varying impacts of dynamic pricing on low income customers
- CPP programs are more likely to negatively impact customer bills:**
  - 35% had a bill increase
  - 11% had a significant increase

*Faruqui, A. et al (2010). *The Impact of Dynamic Pricing on Low Income Customers*. IEE Whitepaper.
** Entergy New Orleans, Inc. (2014). *Advanced Metering Infrastructure Pilot Final Project Description*. US DOE.

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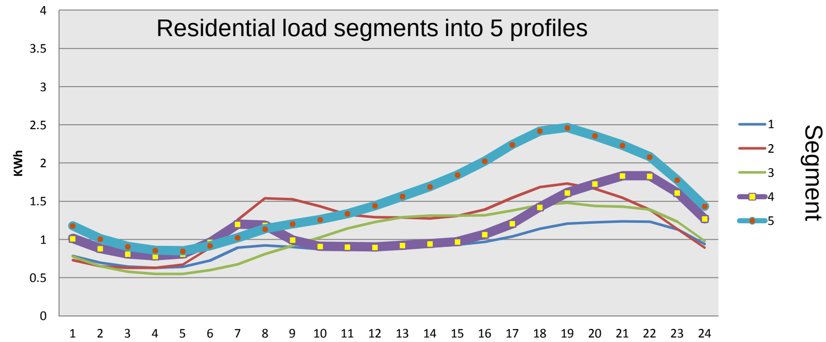
PGE Load Segment Summer Residential Profiles



- **59 % of summer peaks related to 50% of customers**
  - Homeowners in large single family homes
  - Gas heated / air conditioned homes

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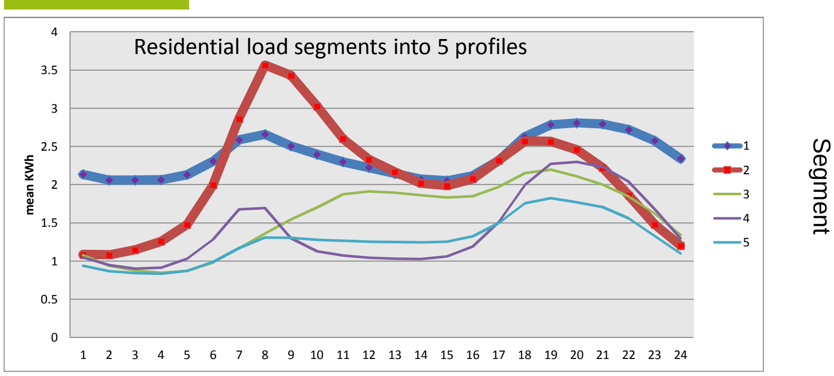
PGE Load Segment Winter Residential Profiles



- **48% of winter peaks are from 31% of customers**
  - Likely to have electric heaters and water heaters
  - Tend to live in smaller homes or multi-family homes; most are renters

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What Determines When Events are Called?

Conditions determine DR events

- Load above 3000 MW
- High temperature either above 90 degrees or below 32 degrees
- Forecasted prices and heat rate above $45 per MW
- Plant availability both within PGE and in the region.

Events for Winter 2013 – Winter 2014

Events	12/5/2013	12/9/2013	12/10/2013	January	2/5/2014	2/6/2014	7/1/2014	7/8/2014	7/14/2014	7/28/2014	7/31/2014	8/26/2014	September	12/30/2014	January	February
	Winter 2013						Summer 2014							Winter 2014		
Start Time	5:00 PM	7:00 AM	6:00 PM		4:00 PM	4:00 PM	4:00 PM	4:00 PM	3:00 PM	4:00 PM	2:00 PM	2:30 PM		6:00 PM		
Duration (hrs)	3	2	2		2	2	2	2	4	2	4	4		2		
Driver for Event	Load	Load	Load	No Events	Load	Load	Load	Load	Load	Load	Load & Plants down	Load & Plants down	No Events	Load	No Events	No Events
Forecast (F)	Low of 18	Low of 25	Low of 25		Low of 17	Low of 12	High of 89	High of 90	High of 89	High of 93	High of 90	High of 92		Low of 32		
Weather	Cold and Clear	Cold and Overcast	Cold and Overcast		Cold and Overcast	Cold and Overcast	Hot	Hot	Hot	Hot	Hot	Hot		Cold and Windy		
Percipitation	0	0	0		0	0	0	0	0	0	0	0		0		

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DLC Thermostat Pilot

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2015 Direct Load Control Pilot Overview

- Uses residential programmable communicating ("smart") thermostats for automated demand response under a **bring-your-own-thermostat** structure
- 2-year pilot will target up to 5,000 customers
- Focus on summer season due to stronger likelihood of having controllable systems
- Participants receive an incentive payment for each event season
- **~ $1.5 million** pilot cost – approximately 1/3 represents the on-going payments to customers

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DLC Thermostat Expectations

Pilot

- Sole sourced by a vendor with at least 8000 connected thermostats in PGE's service territory
- Leverage ETO infrastructure investment and incentives
- Customers receive notification on apps, e-mail, and thermostats
- Expect Demand Response for the portfolio yielding 0.7 to 1.2 kW per home or 3.5MW – 6 MW

Program – Scale Additional vendors

- Multiple Vendors with connected thermostats in PGE area
- Leverage ETO infrastructure investment and incentives
- Summer and Winter seasons offered

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Pricing Pilot

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Jan. 2015 MSI-PGE Focus Group Findings

Observations

- Key barrier is the **perception** that customers' daily schedules and routines will not allow for shifting energy use to off-peak hours
- Customers express **frustration** over pricing programs that do not accommodate their lifestyle seeming to **"penalize"** them with on-peak rates during hours they cannot avoid
- The pricing pilot's **Peak Time Plan** had the broadest appeal
- Customers like the challenge to save electricity that Peak Time Rebate presents

Recommendations

- Explore **personalized** bill analysis to motivate customers to try a TOU plan
- Offer **Peak Time Rebate**

"(Peak Time Rebate) would be a competition"

"I could use the (Peak Time Rebate) rewards to become more efficient."

"(Mothers Discussing Peaks) … that is when bath time happens …. That is when families are active. We could make smarter choices …Why penalize families? "

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2015 Pricing Pilot Overview

- 2-year Behavioral Demand Response pilot will target 7,000 customers
- ~ **$2.5 million** pilot
- Winter and summer program
- Tests 2 concepts
  - Peak Time Rebate on usage behavior and system benefit
  - Which TOU structures delivers the most customer response with greater system benefit

	Schedule 7 Control Group	Schedule 7 Informed	Day and Night TOU	Peak only TOU	Revised TOU
Without PTR (# of Cust)	500	at least 250 – 1000	250 - 1000	250 -1000	250 - 1000
With PTR (# of Cust)		250 - 1000	250 - 1000	250 - 1000	250 - 1000
Numbers shown are target cell sizes					

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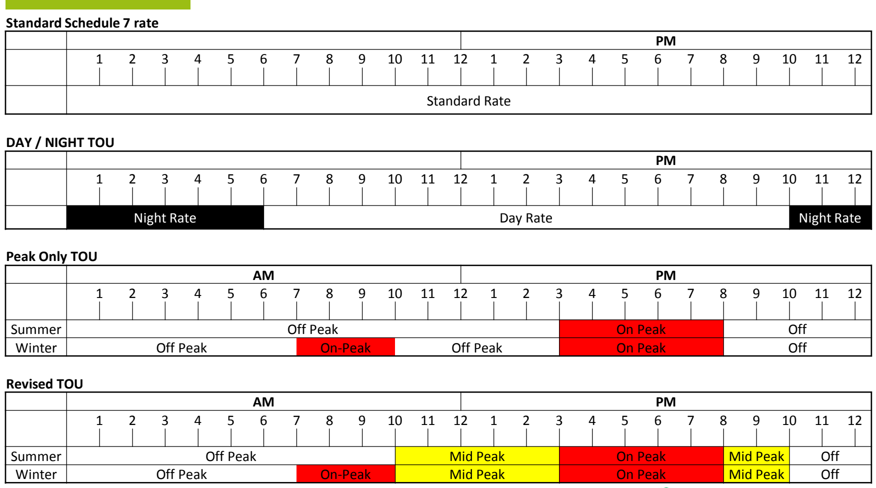
2015 Pricing Pilot Program Hours

Draft



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Pricing Pilot Expectations

- Peak Time Rebate
  - PTR targeted between $0.5 to $1.25 per kWH in early analysis
  - Baseline will be personalized for each customer
  - Event times 1-4 hours in length
- Preliminary rates identified pending further analysis
- RFP issued February 27th, vendor selection anticipated mid-April
- Utilization of an outside vendor allows implementation while customer information system and meter data management systems are being replaced.
- Pilot learning will help inform post-CET program design

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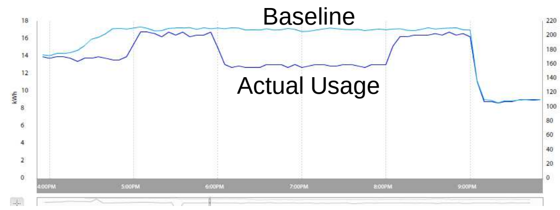
Determining Peak Time Rebate Per Customer

- Each customer get a personalized baseline
- Calculation same as current PGE programs
  - Average hours for 5 highest of last 10 days
  - Adjust for the day of event using 6 hours before event comparison

Samples DR Customer Baseline from 12/30 Event



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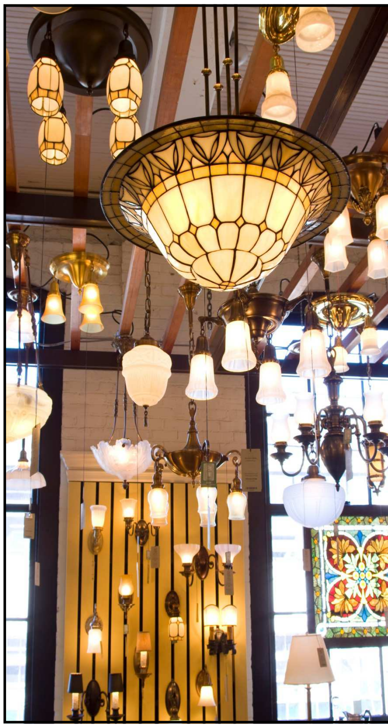

Summary

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Pilots Purpose

DLC Thermostat Pilot

- Leverage market expansion to achieve residential DLC Demand Response
- Investment in this pilot allows movement directly into a scaled program

Dynamic Pricing Pilot

- Continues efforts to deliver dynamic pricing options for consumers
- Understand each program's potential and implementation details

Integrated Resource Planning

- Pilots, evaluation, and programs ramping to scale is required to achieve customer enabled capacity goals in the IRP.

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Potential Timelines

DLC Thermostat program is targeted for this summer requires:
- Contract completed by March
- Commission approval in April

Pricing pilots targeted for September 2015 or March 2016
- Contract Signed by April
- Commission approval in early May for September launch

Impact of delaying the pilots beyond 2015
- DR limited to C & I customers
- Delay DR value of time based pricing until after completion of CET + time for pilot and evaluation (3 years)
- No residential DR in IRP planning cycle until 2022

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Potential Timelines

DLC Thermostat Summer 2015 launch requires:
- Contract negotiations completed in March
- Commission approval in April

Pricing Pilot September 2015 launch requires:
- Contract negotiations completed in late April
- Commission approval in early May for September launch; otherwise launch delayed to March 2016

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Questions

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Supporting Materials for 2015 Pricing and DR Pilots

I have not failed.
I've just found 10,000 ways that won't work.
Thomas A. Edison

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Dynamic Pricing & Demand Response Efforts

Ongoing:

- Time of Use
- Schedule 77 Load Curtailment
- Energy Partner[SM] Automated Demand Response Pilot
- Demand Buyback
- Smart Water Heater Pilot

New for 2015:

- Residential Dynamic Pricing Pilot
- Residential Direct Load Control Pilot

Completed:

- Flex Price[SM] Critical Peak Pricing Pilot (Sch. 12)
- Transactive Node Water Heater Demand Response Pilot

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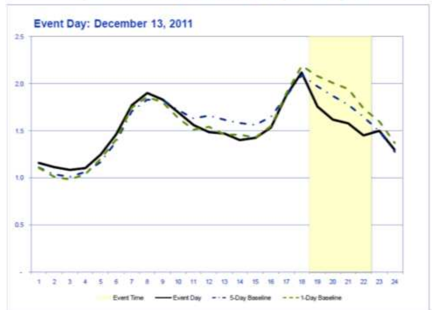
Flex Price

Flex Price SM Pilot Findings

- Critical Peak Pricing events reduced peak by 0.2 to 0.4 KW per customer on average
- Time event to catch peak
- Avoid timing implementation with the start of high bill season
- Customers joined the pilot because they wanted to save money; they left because they weren't saving enough
- Education is key to success

Figure 1: December 13, 2011 Mean kW per Participant



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Past CPP Pilot

- 4 hour event window
- CPP without education or tech
- Previous impacts were around 0.2-0.3 kW for winter
  - Not able to detect summer impacts

Event Date	Max kW (one hour) Impact One-Day Baseline	Max kW (one hour) Impact Five-Day Baseline	kWh Event Day	kWh One-day baseline	kWh Five-day baseline	HDD Base 55
Winter 1						
12/13/2011	0.39	0.25	36.4	37.5	37.6	23.5
1/11/2012	0.20	0.22	35.7	36.8	36.5	19.5
1/18/2012	0.35	0.29	33.4	34.2	32.8	13.0
1/27/2012	0.20	0.29	34.2	34.2	35.5	20.7
2/2/2012	0.31	0.25	29.4	30.3	30.1	12.5
2/13/2012	0.36	0.32	29.8	31.6	32.0	14.4
Winter 2						
1/3/2013	0.26	0.30	37.1	37.0	37.4	23.5
1/4/2013	0.25	0.21	34.1	35.4	36.0	18.0
1/16/2013	0.25	0.28	36.6	37.3	37.5	22.2
2/13/2013	0.17	0.11	27.9	28.9	27.9	7.0
2/19/2013	0.24	0.21	28.7	30.1	29.1	9.5

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Completed Pilot: Flex Price℠

Launched in 2011, this 2-year pilot tested critical peak pricing with 1,000 customers

Summer Hours (May 1 – Oct. 31)	AM 1 2 3 4 5 6 7 8 9 10 11 12	PM 1 2 3 4 5 6 7 8 9 10 11			
Standard Day Monday – Saturday	Off-Peak	On-Peak			Off-Peak
Flex Price Event (when announced*)	Off-Peak	On-Peak	Event	On-Peak	Off-Peak
Sundays and Holidays	Off-Peak				

Winter Hours (Nov. 1 – April 31)	AM 1 2 3 4 5 6 7 8 9 10 11 12	PM 1 2 3 4 5 6 7 8 9 10 11			
Standard Day Monday – Saturday	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
Flex Price Event (when announced*)	Off-Peak	On-Peak	Off-Peak	Event	Off-Peak
Sundays and Holidays	Off-Peak				

Pricing per kWh	
Off-Peak	5.81¢
On-Peak	8.31¢
Event	40¢

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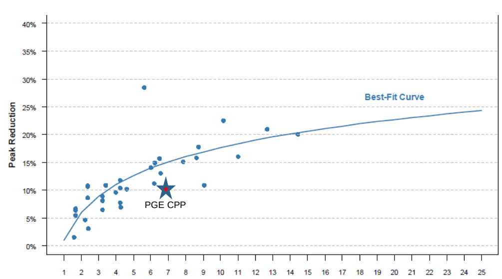
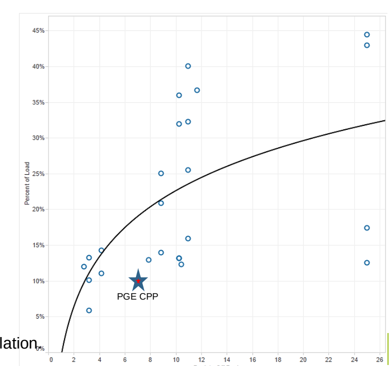
Price Signal

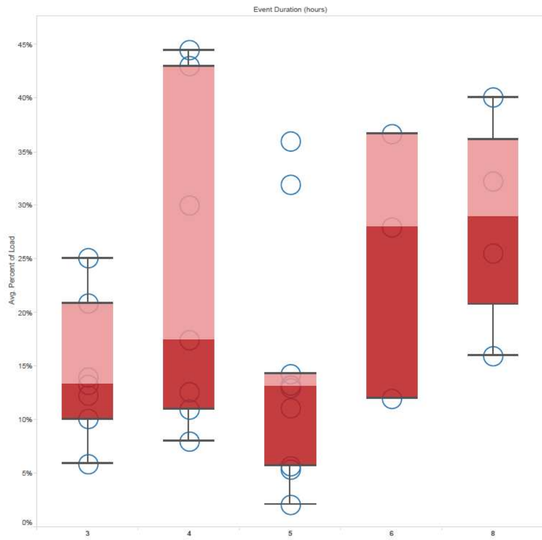
- Strong relationship in price
  - PGE CPP had price to peak ratio ~7 and got about 10% reduction
    - Slightly lower than other studies
- Brattle* (pre-SGIG): DOE** (SGIG):





* Faruqui and Palmer (2011). *Dynamic Pricing and its Discontents.* Regulation.
** Internal analysis of SGIG studies to date

Event Duration



- Looking at DOE SGIG studies, there does not appear to be a strong relationship between duration and impact

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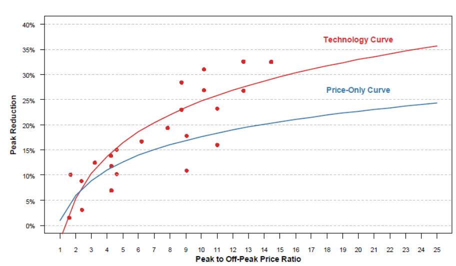
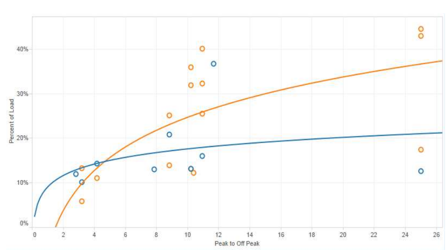
Technology

- Enabling technology both increases overall impact and price-responsiveness
  - Tech increases median impacts from ~13% to 23%

- Brattle (rates only):

DOE (SGIP):





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PTR vs TOU Rates

- Based on DOE studies, PTR appears to have slightly lower impacts
  - Median: 10% vs. 15%
- However, also had lower drop-out rates, despite often being an opt-out structure:
  - Median: 14% vs. 22%
- No adverse impact on customers that don't save
- Reduces potential for free riders because payment is made based on customer-specific baselines

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Education/Feedback

- HER programs have consistently found savings
  - ETO currently has program
- Studies have found significantly higher savings during peak hour from HERs
- DOE studies show slight increases in impact when alerts or web portals included as part of program (~2-3%, not significant)
- OPower has begun to roll out "behavioral demand response"
  - Basically, peak time rebate without the rebate
  - Preliminary results indicate ~3% savings

* OPower White Paper. *Transform Every Customer into a Demand Response Resource*.

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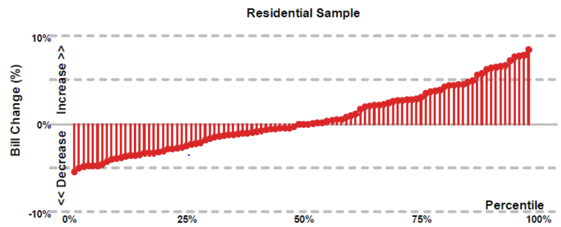
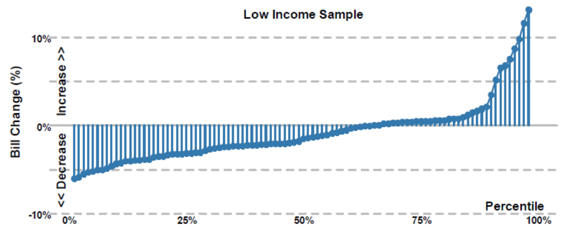
Impact on Low Income

- Per Brattle
  - Adverse bill impacts lower for LI than non-LI
    - Roughly 65% were better off immediately
    - PTR has no impact
  - Savings equal or slightly less than for non-LI
    - On average ~75% of non-LI





Thermostat Savings in other studies

- HVAC DLC programs popular in the rest of the country
  - Primarily for AC purposes
  - These programs typically save 1-1.5 kW (~50% of load)
  - Smart thermostat (Nest, EcoFactor) programs to date have achieved similar savings
- Bulk of NW work has been for WH
- Kootenai (with BPA) ran a space heat pilot in 2012
  - Achieved impacts of ~XX kW
- Brattle potential study assumes:
  - 1 kW for AC
  - 0.6 kW for space heat

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Future PCT Potential

- Navigant forecasts ~22% penetration of PCTs by 2023
  - Electric space heat has been stable around ~40%
  - Central AC penetration is growing (currently at 55%)
  - At current levels:
    - 22%*40% = ~9% potential winter participants (~66k households)
    - 22%*55% = ~12% potential summer participants (~90k households)
- Using Brattle assumptions:
  - Winter potential: ~40 MW
  - Summer potential: ~90 MW

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Summary of Research on Pricing: Opt-in vs Opt-out

- As expected, opt-out studies achieve much higher participation rates
- Opt-in:
  - Realistic range of 5%-20%
- Opt-out:
  - Recruitment around 80%
- Drop-outs lower for opt-out than opt-in

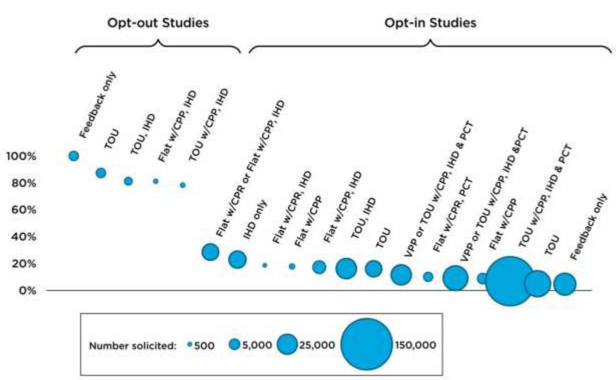

Figure 8. Recruitment rates for each solicitation effort.

Total solicitation efforts listed: 19. Circle size represents the total number of customers solicited.

* USDOE. *Analysis of Customer Enrollment Patterns in Time-Based Rate Programs – Initial Results from the SGIG Consumer Behavior Studies.*

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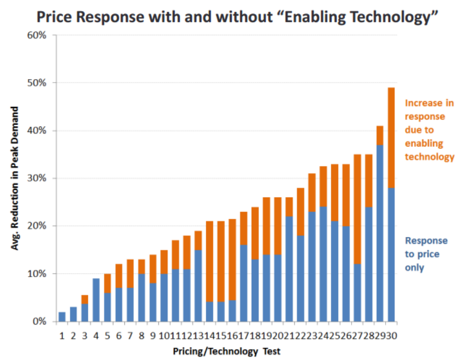
Summary of Research on Pricing: Technology

- Programmable Communicating Thermostats (PCTs) and In-Home Displays (IHDs)
- Increase load reduction by ~5-10% of total load (similar between CPP/PTR)*
- Bigger impacts when DLC enabled



* PGE internal analysis of DOE SGIG results. Similar results found in Faruqui, A. & Sergici, S. *Household response to dynamic pricing of electricity–a survey of 15 experiments*. Journal of Regulatory Economics (2010), 38:193-225
** Sergici,S. (2014).

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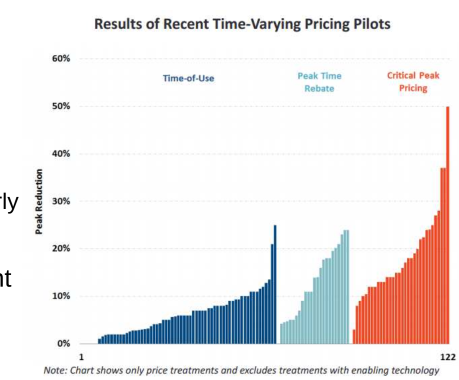
What Other Utilities Have Found, cont.

- CPP and PTR have similar impacts
  - CPP slightly higher in some cases
  - Typical impacts of 10-20% of peak
  - PTR has no adverse bill impacts, particularly important for low-income populations
- Opt-out programs have higher enrollment rates
  - Opt-in: 5-20%, Opt-Out: ~80-90%
- Enabling technology increases impacts by 5-10%



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Case Study: Baltimore Gas & Electric*

- Tested a variety of pricing programs starting in 2008 as part of AMI business case
  - Based on pilot results, deployed in 2012
- 1.2 million electric customers
- For pilot, used opt-in structure
- Tested CPP and PTR
  - "…customers show the same responsiveness to dynamic pricing whether it is expressed as a price increase during critical hours or as a peak time rebate." (2011).
- Found impacts of ~25% during events
  - ~+5% boost from tech, addition 5% from control switch
- Ultimately chose opt-out PTR for all electric customers with AMI**
  - Coupled with customer engagement and energy information platform
  - Allowed enabling tech/switches

*Faruqui, A. & Sergici, S. (2011). *BGE - Dynamic pricing of electricity in the mid-Atlantic region: econometric results from the Baltimore gas and electric company experiment.* Journal of Regulatory Economics. 40:82.
** Conversation with BGE, February 2015.

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What PGE Research Shows

Pricing Programs

- 20% of residential customers report they would definitely switch to time-based pricing; 31% are "likely" to switch
- Primary drivers for joining are a desire to save money and have control over their bill

Thermostat Demand Response

- 18% of customers would definitely participate in demand response; 40% are "likely" to participate
- 22% of US residences are expected to have a Programmable Communicating ("Smart") Thermostat (PCT) by 2023
- Smart Thermostats take the effort out of participation

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Outside Vendor

- RFP issued 2/27 for target selection by 4/30
- Potential Vendors
  - OPower
  - Tendril
  - C3
  - Autogrid
  - Comverge
- Work with outside vendor will dovetails into CET implementation

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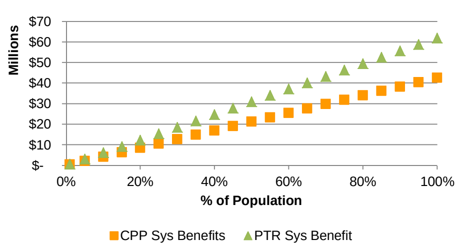
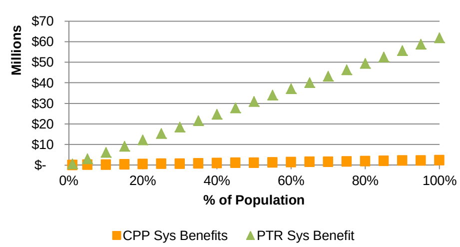
CPP Customers Require Bill Discount to Sign up

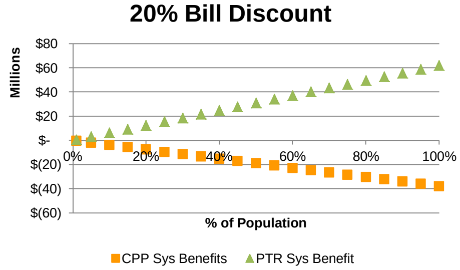
10% Bill Discount



15% Bill Discount



20% Bill Discount



Assumptions	CPP	PTR + TOU
Event Impacts (KW)	1.2	1
Event hours per year	40	40
Rebate	-0.4	1
Cost to Recruit	$ 236.00	$ 15.00
Avrage PGE Bill	$ 92.08	
Assumed CPP Bill Discount		
Residential Install base	728000	

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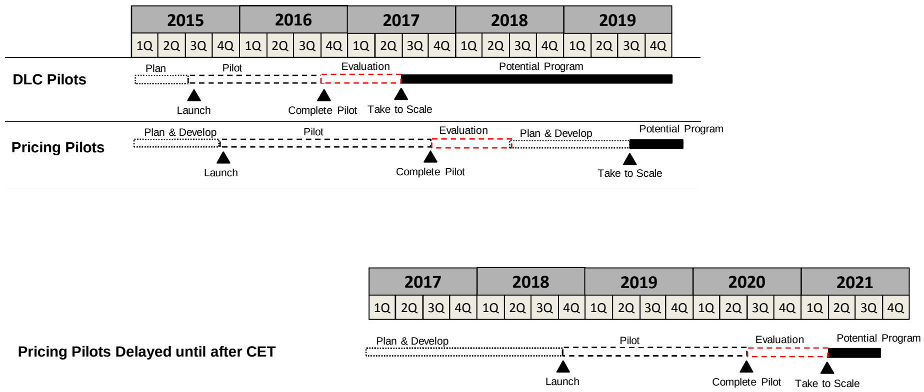
Potential Timelines



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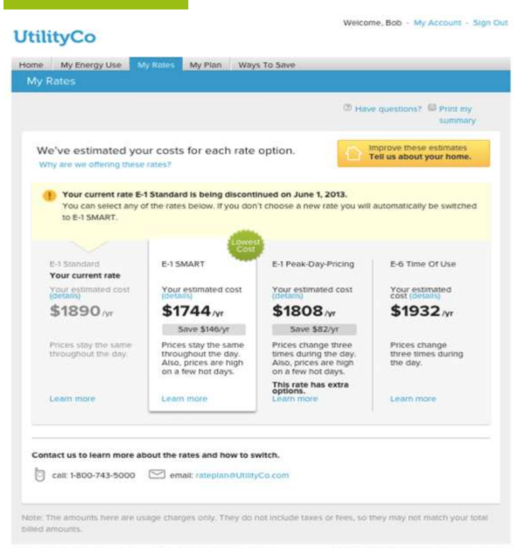
Rate Compare Example



- Sample from one particular vendor
- All perspective vendors have this capability
- Customers needs to see this to commit.

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