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August 26, 2016

Via Email
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Public Utility Commission of Oregon
201 High Street, Ste. 100
PO Box 1088
Salem, OR 97308-1088

Attn: OPUC Filing Center

Re: **UM 1657 PGE Reply Comments – 2016 Smart Grid Report**

Enclosed for filing are Portland General Electric's Reply Comments regarding its 2016 Smart Grid Report submitted in Docket Number UM 1657. PGE also includes the following Attachments:

- Attachment A: AMI Operational Savings Report (July 1, 2011 to December 31, 2011)
- Attachment B: AMI Operational Savings Report (January 1, 2012 to June 30, 2012)
- Attachment C: PGE Scoping Plan for AMI Benefits
- Attachment D: PGE Presentation – March 12, 2015
- Attachment E: Portland State University Project Proposal

This document is being filed by electronic mail with the Filing Center.

If you have any questions or require further information, please contact me at (503) 464-8937. Please direct all formal correspondence and requests to the following email address: pge.opuc.filings@pgn.com

Sincerely,

for

Stefan Brown, Manager
SB/sp

Enclosure

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1657

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Annual Smart Grid Report	REPLY COMMENTS OF PORTLAND GENERAL ELECTRIC

Portland General Electric ("PGE") submits these reply comments in response to comments submitted by the Oregon Public Utility Commission ("OPUC") Staff, the Oregon Department of Energy ("ODOE"), and NW Energy Coalition ("NWEC") regarding PGE's 2016 Smart Grid Report (the "Report"). PGE appreciates the input it received on the Report and looks forward to continued collaboration around future Reports and Smart Grid development in Oregon.

More specifically, PGE addresses the specific comments and questions raised by parties in these Reply Comments. PGE's Reply Comments are organized into the following sections:

- Section I: The Future of the Smart Grid Report[1];
- Section II: Customer Programs;
- Section III: Advanced Metering Infrastructure;
- Section IV: Software;
- Section V: Metrics;
- Section VI: Cybersecurity;
- Section VII: Research and Other Projects; and,
- Section VIII: Conclusion.

[1] Section I includes PGE's reply comments regarding the future evolution of the Report and Distributed Resource Planning generally.

I. The Future of the Smart Grid Report

OPUC Staff, NWEC and ODOE comments all included interest in how the Smart Grid Report might evolve in the future, specifically with regard to the role that Distributed Energy Resources (DERs)[2] might play in the Report going forward. Stakeholders also indicated interest in PGE adopting a specific approach to "Distributed Resource Planning," similar to what the California legislature recently required of investor-owned utilities.[3]

PGE appreciates the invitation to consider the future of the Report, and in summary, views the Smart Grid Report as the appropriate vehicle for holistically discussing the development of additional DERs in PGE's service territory. PGE sees value in using the Smart Grid Report as the central hub for coordinating the work that is occurring in various dockets and proceedings at the OPUC focused on DERs along with planning for how DERs may be deployed in future customer pilots, programs, and grid investments.

Determining the ways in which DERs may be able to improve the reliability, affordability, and sustainability of PGE's electric service is a complicated undertaking. For example, PGE will need to determine methodologies for quantifying the benefits DERs bring to PGE's system and its customers, including their value as generation resources, their ability to defer or avoid transmission and distribution investments, and other benefits individual customers may receive, such as increased reliability. PGE will also need to continue to study the challenges DERs may introduce, which were identified on page 45 of PGE's Report. In both instances, pilots focused on DERs will be useful to PGE to determine if PGE's assumptions about the benefits DERs may bring (and the challenges they may introduce) are realized in practice. Additionally, the electric industry will need to develop new tools to model the distribution system in more complex ways to see if there are site-specific locational values for DERs.

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[2] PGE uses the term DERs to mean distributed generation resources, energy efficiency, event-based pricing, energy storage, electric vehicles, demand response technologies, and combinations thereof.

[3] OPUC Staff asked if an assessment of DERs ability to reduce costs on the transmission and distribution system would "be a foundational step to a more comprehensive planning document similar to the DERP CA utilities develop?" and "What system and Company resources would be necessary to successfully develop a PGE DERP?" NWEC suggested "it is time to move forward with an initial effort for distributed resource planning. We recommend the California approach…"

Cost-effectiveness

At present, there are a number of dockets and proceedings through which the OPUC, PGE and other utilities, and stakeholders in Oregon are considering DERs, including their potential cost-effectiveness.[4] It would be beneficial for the next iteration of the Smart Grid Report to compare the cost-effectiveness methodologies of various DERs that PGE has developed or is beginning to develop (e.g., demand response, electric vehicle programs, and distributed energy storage). PGE's work would be an addition to the cost-effectiveness methodology the Energy Trust of Oregon applies to energy efficiency and the work undertaken by parties in OPUC Docket No. UM 1716 (i.e, the resource value of solar). PGE's interest in this work is to establish a consistent approach to these various cost-effectiveness methodologies and to avoid any potential conflicts amongst the methodologies. This work would require greater collaboration between PGE and ETO to determine the value of energy efficiency, particularly associated with the capacity value of efficiency.

Pilots

The work associated with piloting DERs is particularly important to verify assumptions about the values the DERs bring (and the challenges they may introduce). As the Report outlines, PGE is currently piloting a number of DERs, including three associated with demand response (Energy Partner – focused on industrial customers; Nest Rush Hour Rewards; and PGE's Flex Pricing Pilot, which includes an examination of Peak Time Rebate). PGE anticipates adding (1) a number of transportation electrification pilots to achieve the goals identified for utilities in SB 1547, (2) distributed storage pilots to meet its obligation under HB 2193, and (3) additional demand response pilots to achieve the demand response targets PGE anticipates resulting from the 2016 IRP.

PGE considers these pilots to be foundational steps to determine the actual value of given DERs in PGE's service territory. For example, while PGE anticipates a level of cost-effectiveness in its demand response programs based on the results of its pilots, the actual cost-effectiveness of a program can only be

[4] AR 599 (EV Program Application); AR 603 (Community Solar Rulemaking); UM 1514 and UM 1708 (Deferrals for DR Pilots); UM 1716 (Resource Value of Solar); and UM 1751 (Energy Storage Program Guidelines).

understood once customers actively participate in and respond to demand response events (i.e., each customer responds to the signals differently). As a result, PGE believes that DER pilots should be planned for and collectively reported out on in future Smart Grid Reports. The Smart Grid Roadmap, included in the 2016 Report, demonstrates PGE's interest in, and a high-level approach to, this planning function. Reporting out on DER pilots collectively provides an opportunity to highlight lessons that may only appear by comparing the results of different pilots to one another.

The Report and IRP approaches

It is important to note that a DER planning function in future Smart Grid Reports should have a mid-term focus (i.e., 5-years into the future) and create roadmaps for new pilots and programs associated with DERs and related smart grid investments. Such a near-term time frame is appropriate, because PGE anticipates these roadmaps changing regularly due to the lessons from pilots and the emergence of new technologies in the marketplace. PGE employs the roadmap approach to planning to ensure PGE has a nimble and flexible approach for developing DERs. Determining the appropriate role of DERs within PGE's resource mix over the long-term is a function for the IRP, PGE's foundational planning document. PGE's IRP process currently incorporates some DERs, including energy efficiency, dispatchable standby generation, and demand response, by focusing primarily on the value of the generation services and the impacts to customer load these DERs may provide. The 2016 IRP also includes an analysis of the value of adding grid-connected energy storage to given resource portfolios. This comprehensive analysis is used to determine the best combination of cost and risk from a total resource portfolio perspective and joins the information developed from all aspects of the electric supply chain to ensure evaluation is performed on a level playing field.

Locational value of DERs

In addition to coordinating the work on DER cost-effectiveness, and planning for and reporting out on pilots, PGE shares stakeholders' interest in better understanding the "locational value" – or the value to the distribution and transmission grid depending on where DERs are placed. Doing so, however, requires distribution planning to evolve into a significantly more complex undertaking, and the tools to effectively move to this new approach are still immature. In April 2016, the Electric Power Research Institute (EPRI) published a report focused on the locational value of DERs, which notes the need for additional tools:

> *New distribution power models, and the data they require, are needed to accommodate an improved understanding of system impact. Challenges revealed by the case studies point to the need for improved customer load models that capture the temporal and spatial variations of changing demands at higher levels of granularity; advancement of forecasting methods capable of characterizing both customer inclination to adopt various DER technologies as well as how they are likely to apply such technologies; and planning methods and tools capable of capturing the increasing levels of variability and uncertainty and risk to the system.*[5]

In other words, to provide the information many stakeholders desire related to locational value – which is an essential function of Distributed Resource Plans in California – PGE would have to enhance the system infrastructure to capture the level of data required, and the industry would need to develop significantly more robust planning tools. Given the relatively low electric prices and level of DER adoption in PGE's service territory, it is not in our customers' interest for PGE to be at the cutting edge of the development of the tools needed to perform this more complex distribution planning. In short, we are not California. The more prudent path is to monitor activity in other parts of the country, and consider installing data gathering and monitoring equipment in our pilot projects as appropriate. Accordingly, PGE does not share NWEC's interest in transitioning the Smart Grid Report into a Distributed Resource Plan at this time. Rather, PGE intends to continue to monitor the development of additional distribution resource planning tools, and adopt them as they mature sufficiently to provide meaningful insights into PGE's existing processes. There is a role for reporting out on the lessons from such monitoring within the Report.

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[5] EPRI, Time and Locational Value of DER: Methods and Application, Executive Summary for EPRI Report 3002008410, April 2016, p. 6-7. Available at: http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002008687

PGE acknowledges the potential role of DERs in the utility system, and the Smart Grid Report is the appropriate venue for exploring this role. At this point, the most cost-effective way to explore the role is to patiently develop Oregon's expertise in DER's emerging fields while other states do the costly and time-intensive pioneering work to build and refine the models and methodologies needed to determine if and when DERs can lower the cost of distribution services for customers.[6] PGE sees the evaluation of DERs as an iterative process, in parallel with PGE developing more sophisticated data and methodologies to gain experience through its portfolio of DER pilots and programs.

Specifically, PGE believes future Smart Grid Reports should include:

- Consolidation and coordination of cost-effectiveness analyses for DERs;
- Five-year roadmaps for DER pilots and programs;
- Collective reporting on existing DER pilot and program outcomes;
- Discussion of the development of tools and methodologies for assessing the values DERs may bring to PGE's system; and,
- An adjusted reporting cadence to make the Report every other year, aligning with the draft rulemaking for the Transportation Electrification Plans.

Issuing the Report on a biennial basis will provide PGE with sufficient time between reports to effectively work on Smart Grid investments and demonstrate progress along the roadmap. Additionally, PGE believes stakeholders may find value in more regular meetings with PGE to discuss DERs (and other topics within the Report) and the potential value DERs may hold for PGE's customers. Accordingly, PGE would host regular Smart Grid stakeholder meetings in between reports if the reporting cadence was reduced from an annual to a biennial requirement.

[6] Work on the locational value of DERs is especially active in New York, California, Hawaii and Texas (ERCOT).

II. Customer Programs

1) Customer Trends

a) OPUC Staff Questions

Under the category titled "Customer Engagement and Services", Staff asked a number of questions regarding how PGE monitors customer trends and customer voices and what opportunity there is for utilizing smart grid initiatives to address customer trends.[7]

b) PGE's Response

PGE focuses most of its customer research on operational topics, such as customer satisfaction and customer experience. PGE uses this information to inform and improve the services and experiences it delivers. PGE conducts this research on a regular schedule, from quarterly to annually, depending on the customer segment that is targeted. PGE's customer satisfaction research generally targets three core customer segments: Residential customers, Business customers, and Key (actively managed) customers. In addition, PGE conducts some interaction-specific research to assess how well the Company serves customers through particular channels (e.g., through PGE's website or call center).

PGE devotes relatively few market research resources to monitoring customer 'trends' – which PGE interprets to mean broad indications of the attitudes, beliefs, values, opinions, or future desires of its customers. Instead, PGE chooses to focus its limited research resources on conducting ad-hoc, custom research projects to provide market insight for specific product- or service-development opportunities (e.g., transportation electrification survey and focus groups for SB1547 program planning). Themes and insights gathered from these projects are utilized in designing customer smart grid programs (i.e. Demand Response, EVs, etc.), outreach and education, and program implementation.

While PGE collects some unstructured data (e.g., customer comments) from a variety of sources it is not analyzed in any systematic way at this time. Presently, this customer feedback is used anecdotally – much like the other qualitative research PGE conducts. While not representative of PGE's customers, it nonetheless can help add context and depth to PGE's understanding.

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[7] Staff's Comments at p. 6.

2) Pricing Pilot/Flex (Order No. 15-314 Requirement #2)[8]

a) OPUC Staff Questions

What are PGE's contingency plans if participation goals are not on track? Will results be "experimentally sound" if participation levels are not met?

b) PGE's Response

The pilot tests several time-of-use rates, peak time rebates, and behavioral demand response program options. Each of these program options has specific recruitment targets. Program options that fall significantly below recruitment targets will not produce statistically quantitative significant results for evaluating program performance.

PGE will continue to recruit for all program options for which participation levels have not been met. PGE has utilized data from initial outreach efforts to adapt the outreach strategies, timelines, and messaging to optimize customer enrollment. The modified campaign is performing above expectations. It is important to acknowledge that because the pilot design pre-assigns prospective participants to certain rate designs (for the purposes of developing a random sample), PGE is not able mass market any one design.

To continue to drive enrollment, PGE has increased the size of the recruitment pool, lengthened the recruitment periods, and allowed for more outbound customer touchpoints. Before this upcoming winter, PGE presently expects to recruit the majority of participants needed to achieve statistically significant sample groups. PGE anticipates program recruitment targets will be realized before summer 2017.

If program targets are not met, PGE risks test groups being too small to get statistically significant results. To reduce this impact, several program test groups have been prioritized to ensure that PGE does realize some statistically significant test groups. Alternatively, some of the tested program options can be analyzed by pooling participants across program options together to deliver statistically quantitative significant results.

[8] Staff's Comments at p. 3.

c) OPUC Staff Questions

How has the relationship with Nest been? Has the Company experienced any operational or data exchange issues?

d) PGE's Response

The relationship with Nest is positive. PGE and Nest have on-going meetings to exchange ideas, information, and plans about the program, marketing, and evaluation.

PGE has not encountered any significant data exchange issues with Nest, however PGE is working with Nest to expand their data transfer capabilities to PGE's pilot evaluation contractor.

PGE is the first utility to run a summer and winter program with Nest. The Nest operating platform needed adjustments to function within the new specifications. Similarly, Nest needed to adapt to allow PGE customers to enroll continuously into the program without a specific enrollment season.

e) OPUC Staff Questions

Why have no Flex pricing events been called?

f) PGE's Response

PGE did not encounter weather conditions that would warrant the calling of a Flex pricing event in June, 2016. Since then PGE dispatched Flex pricing events on July 27, 2016 and July 29, 2016.

3) Energy Tracker (Order No. 15-314 Requirement #3)[9]

a) OPUC Staff Questions

How has the Company continued to achieve growth in the Energy Tracker program? What lessons can be learned from engagement strategies and execution?

b) PGE's Response

To foster growth, PGE has promoted Energy Tracker through the following: email campaigns, bill inserts, newsletter circulations, street fairs and community events, as well as Energy Monitoring classes held by PGE.

[9] Staff's Comments at p. 4.

Sending extreme weather related emails that urge customers to use Energy Tracker to address their usage has seen positive results. Also our contact support center has had positive results connecting with customers and empowering them by introducing them To Energy Tracker. Through focus groups as well as other interactions, we regularly hear that customers appreciate the Energy Tracker tool.

c) OPUC Staff Questions

What are the company's plans to maintain growth?

d) PGE's Response

For commercial customers PGE is planning to provide customers with better and more specific energy efficiency tips.

4) Smart Water Heater Pilot

a) NWEC Comment

We (NWEC) believe(s) faster scale-up of this resource is feasible over next 3-5 years (due to entry of firms across supply chain). NWEC suggests further coordination by PGE with BPA, other utilities, and NEEA on smart water heaters to aid transmission congestion issues. This is also consistent with NWPCC efforts/goals.

b) PGE's Response

PGE concurs with NWEC and has already started to work with BPA on a weekly basis, NEEA on a bi-weekly basis, and PNNL on a monthly basis to advance smart water heaters not only for PGE but for the region as a whole. Together with BPA's demand response/energy efficiency group PGE is leading a regional pilot with smart water heaters that now include six other regional utilities and two manufacturers of smart water heaters, namely AO Smith and General Electric/Haier.

III. AMI

a) ODOE Comment

ODOE would like to see a quantification of both the direct benefits associated with AMI Deployment (e.g., elimination of PGE's direct labor and fuel costs associated with truck rolls for manual meter reads) and any associated indirect benefits (e.g., benefits to grid operation, improved customer service, etc.).

b) PGE's Response

In accordance with Commission Order No. 08-245, PGE submitted two reports on operational savings derived from PGE's advanced metering infrastructure system (AMI). These reports were submitted on July 31, 2012 and November 2, 2012, and are provided as Attachments A and B to this response.

On July 27, 2007, PGE submitted a Scoping Plan (i.e., PGE Exhibit 103 in Docket No. UE 189), which was a very preliminary analysis of the informational benefits to be derived from AMI. The Scoping Plan has been provided as Attachment C to this response. Since then, PGE has not performed any subsequent analysis of the overall informational benefits to be derived from AMI. Instead, PGE has focused on implementing applicable pilots and/or programs and evaluating their costs and benefits on an individual basis.

c) OPUC Staff Questions

What functionality does PGE's current AMI lack that is available in up-to-the-date AMI given that PGE's AMI is approximately 7 yrs. old, specifically:

- Are there any customer DSM opportunities that are inaccessible become of this lacking functionality?
- Do components of SB 1547 and HB 2193, such as EV infrastructure, battery storage, and greater DR, face hurdles in integration in PGE's operations & planning because of PGE's available AMI functions?

d) PGE's Response

PGE is not aware of any major advances in AMI since 2010 that have resulted in widespread adoption of DR or other DSMs via the meter. All of today's DR programs at scale, primarily utilize 1-way communications broadcast utilizing communication devices installed by an electrician (not using AMI). PGE is aware that there are AMI pilots utilizing ZigBee chips to speak to specific appliances or in-home displays. However, the lack of major household loads that use ZigBee (or any embedded communication method), and the lack of a, single, standard communications protocol for in-home device communications, limits any modern approach to demand response at scale.

"Internet of Things" device manufacturers are leaning away from the meter as a platform for DR and leaning towards Wi-Fi instead. Most "smart" devices on the market today use Wi-Fi (e.g., Nest Thermostat) or have add-on adapters that use Wi-Fi, (e.g. the GE Geospring heat pump water heater). Our AMI vendor, Sensus, does offer a demand response device which could turn some appliances on or off, but it does not allow moderating controls of the devices. These devices would require additional software and potentially more communication infrastructure. Today PGE believes that Wi-Fi provides the best real time functionality, but availability is limited to very few devices that have actually been sold. PGE is focusing pilot efforts on utilizing these devices (e.g. Nest Rush Hour Rewards Pilot; Workplace Charging Demand Response demonstrations) and working with BPA and NEEA to promote a standard communication interface [ANSI/CTA-2045] on electric water heaters.

Although components of SB1547 and HB 2193 may create challenges in PGE's design efforts around metering or sub-metering certain devices (e.g. batteries or EV chargers), PGE's current AMI will not be a limiting factor in how PGE plans and operates future opt-in programs associated with these bills.

IV. Software

a) <u>OPUC Staff Questions</u>

Under the category titled "Customer Engagement and Services," Staff sought a comprehensive narrative regarding Customer Information Systems "CIS" and Meter Data Management Systems "MDMS" and their upgraded capabilities, including: progress to date, expected completion date with timeline, capabilities that will be available that are currently not, what types of services could be offered that have not already been discussed, and the nature and extent of how these systems will enable easier customer access to DSM and pricing programs.

b) <u>PGE's Response</u>

Progress to Date

PGE's CIS and MDMS replacement project (Customer Touchpoints) is completing the first of its three iterative design/build/test cycles (Cycle 1) in September 2016. In each of the three cycles, business processes are analyzed and defined, system components are built to support them, and the updated system is tested to make sure the new capabilities work as planned. Subsequent cycles take on increasingly more complex parts of the system until – after Cycle 3 – the new system is fully built and ready for end-to-end testing, user acceptance testing and deployment (see timeline below).

Cycle 1 focused on approximately 54 business process categories covering everything from customer basic start service and program enrollment to managing field operations and calculating bills. During Cycle 1, the project team:

- Implemented a base version of the Oracle Customer Care & Billing (CC&B) platform for use in business process design workshops.
- Designed a series of business processes to leverage the CC&B technology and converted those into functional and technical requirements.
- Configured multiple bundles of functionality to produce working operational features.
- Completed unit and assembly testing on functionality developed during Cycle 1.

Expected Completion Date & Timeline

Deployment of the new CIS, MDMS and associated Oracle applications (collectively termed Customer Care and Billing (CC&B henceforth) is scheduled for the end of March 2018.

The project timeline is as follows:

Customer Care and Billing Project Timeline

- Project Mobilization (Cycle 0) ....July 2015 – April 2016
- Cycle 1: Business Process Design/Base Solution Implementation..April 2016 – Sept. 2016
- Cycle 2: Complex Requirements & System Integrations ....Sept. 2016 – Feb. 2017
- Cycle 3: Exception Processing, Analytics, Reporting ....Feb. 2017 – June 2017
- End-to-End Testing/Defect Resolution[10] ....June 2017 – Dec. 2017
- Operational Readiness Testing ....Sept. 2017 -- Feb. 2018
- Training ....Sept. 2017 – Mar. 2018
- Full System Go-Live...Mar. 2018

Capabilities that will be available that currently are not

The new CC&B system allows for greater flexibility, increased automation and centralized data for reporting. This will help enable PGE to offer a wider range and flexibility of pricing options, products and services, and access to data. The new systems also allow new or existing programs to be more scalable for future customers by reducing the operational complexity and manual labor associated with operating these programs. They also enable marketers to tailor programs to align with specific customer segments and needs in a way that is more granular than today.

- Customer and program data currently housed in multiple locations will be consolidated into a single system. This enables centralized logging and lead tracking, and increased visibility into how customers are interacting with PGE. It also strengthens interactions with customers,

[10] Testing occurs throughout the project, including assembly testing during each Cycle. The length of time devoted to assembly testing, end-to-end testing, defect resolution and operational readiness testing is due to the complexity of the systems and the number of integrations necessary with other enterprise systems as well as systems external to PGE. The rigor with which the project is undertaking testing reduces overall project risk.

provides a better customer experience and, potentially, the development of more refined and targeted program offerings.

- Eligibility criteria can be embedded in the system for product offerings or campaigns. This will help Customer Service Representatives (CSRs) determine customer eligibility and promote relevant programs to customers who can most benefit from them. Program managers will be able to pull target lists directly from CC&B based on predefined criteria.
- Enrollment data will be centralized. Enrollment data from marketing campaigns is currently a manual and semi-automated effort, and the data feeds into several systems. In the future, enrollment data will be centralized in CC&B. The data will be accessible to users for analyzing, designing and managing campaigns.
- Customer interactions will be stored within CC&B. This provides increased visibility into customer response to program offerings allowing for more effective targeting. These capabilities will enable marketing managers to use the new system to track marketing activity and program adoption rates.
- Ad-hoc queries can be made in CC&B by a larger number of users. This includes program managers, program designers and business analysts, who will be able to rely less on special programming performed by IT resources, or fixed-content reports that don't adapt over time. The result will be an expedited ability to implement, manage and monitor the success of DSM and pricing programs.

PGE plans to improve the way it delivers and maintains DSM products for customers, including smart metering, demand response and pricing programs using functionality provided by CC&B.

- CSRs will be able to enroll new customers into programs at the time they sign up for service. As they enter a new customer's information, the system determines which programs a customer is eligible for and the CSR can conveniently enroll the customer into a specific PGE offering. For customers who choose to not enroll in a program offering, CSRs will be able to log the reason. Based on this additional information, program designers and managers can refine programs to better suit customer needs.

- Enrollment tracking will occur within CC&B. Currently, tracking enrollment is a manual process and the data is collected in multiple places. The new system will allow this data to accessible in one system, accessible to users in PGE's Customer Strategies & Business Development department.
- With CC&B, program managers and analysts can access the system to make modifications with less reliance on IT. Data models for products and programs currently are stored within Banner CIS. Modifications require IT support, which can extend timeframes for implementation. In some cases, PGE intends to expedite the process for product modifications and new program rollouts by enabling program managers to make modifications to CC&B's configuration, without changing the underlying application.
- Currently, most customer data, including correspondence, is collected for the main account holder, i.e., one key individual. CC&B allows other individuals (property managers, maintenance personnel, purchasing or accounting personnel, roommates, former payees, etc.) to be associated with an account. This gives the Company more options for targeting and marketing efforts, and provides a more complete view of the customer. CC&B also includes the capability to include non-electricity customers in the system. This allows product options and extensions to be included in the portfolio that were not practical to introduce previously.
- Program management will include more automated processes. For example, the system can automatically generate follow-up emails or letters, e.g., to customers serviced by third-party contractors or those who have recently enrolled in programs, or notifications of customer renewals or upcoming renewal deadlines can be sent to internal parties as well as customers.
- The Oracle MDM and CC&B systems will capture Demand Response event information for increased visibility into event details. Internal users will be able to use the applications, in conjunction with the Oracle Utility Analytics (OUA) module, to track history of a DR event,

the customers involved, date and program. Customers may be able obtain their DR data from PGE more readily, such as the amount saved per event.

- Easier to determine program eligibility. Program eligibility and billing determinants can be stored at the Service Agreement level so fewer rates are required and it is easier to determine which programs can be offered to a specific customer. This simplifies customer start-up and enrollment processes, and enables CSRs and KCMs to discuss relevant service options with the individual customer.

Types of services that could be offered that have not already been discussed

The implementation or expansion of residential and business DSM and pricing programs, some of which are in pilot stage, will be facilitated by new CC&B systems. The following programs and pilots have been identified as among those benefiting from the new technology.

- Utilization of data streams from third parties (i.e. Nest customer enrollment data).
- Automatic bill adjustments/credits (i.e. DR credits, peak time rebates, etc.), including bill credit calculation.
- Calculate customer energy charges based on a variety of TOU rates.
- Rush Hour Rewards Smart Thermostat Demand Response: the new system will accept vendor enrollment files indicating which customers have earned a rebate and a bill adjustment mechanism for participation (which is currently a manual process).
- On-bill monthly lease payments (for PGE leased equipment at customers' premise)
- Easily implemented & modified one-time fees, variable or fixed monthly fees, etc. which could be utilized for programs such as community solar, EV charging, etc.

Nature and extent of how these systems will enable easier customer access to DSM and pricing programs

As discussed above, CC&B's flexibility and configurability addresses many of the issues and barriers that exist today in design, marketing and managing DSM and pricing program. These include:

- Increased visibility for CSRs and customers into their electricity usage; program qualification, participation and results; and payment/credit status on DR, DSM incentive and rebate programs, etc.
- A suite of integrated modules that give users a single system for accessing customer data, account and service agreement information, billing and credit information, and many program specifics and enrollment options.
- Broader user access to the system, reporting tools and data that make the analysis, design, targeting and management of DSM, DR and renewable energy programs more efficient and effective, bringing those capabilities into the hands of the PGE departments that are consumers of that information.
- Automation of formerly manual or semi-automated processes that will enable PGE to cost-effectively offer more self-service options and customer-desired products and services made possible by the smart grid, including pricing programs that support peak time rebates, net metering and electric vehicles. Decreasing the amount of manual processing not only delivers cost savings for programs, it gives employees more time for higher-value work.

V. Metrics

1) **EV Metrics (Order No. 15-314 Requirements #3)**[11]

a) OPUC Staff Question

What is the methodology behind the ODOT EV data?

b) PGE's Response

PGE has obtained data from Portland State University's Transportation Research Center (TREC). The source for the data is from Oregon DMV, which provides the data to DEQ on a semi-annual basis. DEQ runs the DMV data through a VIN decoder. DEQ shares the output with TREC. DEQ only provides numbers of BEV, PHEV and Hybrids at the ZIP Code level. DEQ is currently not providing make and model data or other any identifying details such as street address or names on registrations. TREC uses this data to prepare reports on statewide EV numbers. Currently, TREC does not have a formal process with the DEQ or ongoing funding to do this reporting on a regular basis.

c) OPUC Staff Question

Will PGE continue with ODOT data in the future or is PGE planning an internal source to provide more accurate data?

d) PGE's Response

For the foreseeable future, PGE will continue to utilize ODOT data, however PGE is evaluating alternative data streams through the SB1547 Transportation Electrification planning process.

2) **Risk Metrics (Order No. 15-314 Requirement #3)**[12]

a) OPUC Staff Question

What are PGE's plans to begin capturing "system risk holding" and "system risk mitigated"? Have the methodologies been developed?

b) PGE's Response

[11] Staff's Comments at p. 4.
[12] Staff's Comments at p. 4.

PGE has developed a risk assessment methodology for in-kind replacement decisions for the vital assets in the transmission and distribution (T&D) system. This assessment methodology has been utilized to develop an initial T&D system risk register, or "system risk holding", and is being leveraged to inform a portion of PGE's T&D investments for 2017 and beyond. While PGE is able to monitor "system risk mitigated" metrics for simple, in-kind asset replacement decisions, development and maturity of the risk assessment methodology, tools, and associated metrics are still underway for more complex analysis scenarios. These complex scenarios include system reconfigurations to address asset and non-asset (e.g., tree, animal, weather initiated outage events) risks, introduction of distributed energy resources (DER), and system expansion to address new customer load. PGE is already capturing "system risk" metrics, however PGE is fine tuning its model to account for the complex scenarios listed above before including these metrics in PGE's Report.

3) **Metrics Best Practices**

a) ODOE Comment

ODOE would like to see PGE research and identify industry best practices with respect to these metrics.

b) PGE's Response

PGE has held three workshops with OPUC Staff and other stakeholders and one public meeting to discuss Smart Grid metrics reporting and best practices.[13]

These workshops have heavily influenced the direction of the Metrics Appendix of the 2015 and 2016 Smart Grid Reports. At PGE's March, 2015 public meeting, PGE identified a number of resources that influenced its thinking in the development of our Metrics appendix including resources from DOE, PNNL, KEMA, Gridwise Alliance, and Accenture:

- https://www.smartgrid.gov/sites/default/files/pdfs/methodological_approach_for_estimating_the_benefits_and_costs_of_sgdp.pdf
- http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-23423.pdf

[13] Workshops: 12/18/2014, 2/25/2015, and 2/9/2016; Public Meeting: 03/12/2015

- http://osgug.ucaiug.org/Shared%20Documents/KEMA%20Smart%20Grid%20Evaluation%20Metrics%20DRAFT.pdf
- https://www.smartgrid.gov/sites/default/files/pdfs/metrics_guidebook.pdf
- https://www.smartgrid.gov/sites/default/files/pdfs/sgdp_rdsi_metrics_benefits.pdf
- http://www.smartgridinformation.info/pdf/4890_doc_1.pdf
- http://www.sciencedirect.com/science/article/pii/S0301421509003395
- http://www.accenture.com/SiteCollectionDocuments/fr-fr/Accenture-Unlocking-Value-Metrics.pdf

Presentation material from this meeting is included as Attachment D.

VI. Cybersecurity

a) OPUC Staff Question

What regional and national policies, requirements, and best practices are currently in place or being developed in addition to those being developed by the NIST?

b) PGE's Response

PGE currently strives to comply with all laws and regulations that govern cybersecurity over PGE assets. PGE currently utilizes the NIST 800 series standards and is evaluating the recently released Cybersecurity Framework. PGE is not aware of regional or national policies governing cybersecurity. PGE regularly monitors and reviews standards developed by a number of bodies that help PGE guide its internal cybersecurity policies and requirements.

c) OPUC Staff Question

Does PGE plan to adhere to all voluntary practices? If not, why not?

d) PGE's Response

Unless a practice is mandated by law or regulation, it is voluntary. PGE does not intend to adhere to all voluntary standards and practices as that would be cost prohibitive and could negatively impact reliability of power systems. Instead, PGE evaluates the practices recommended in industry standards such as NIST for applicability, effectiveness, and risk mitigation at PGE to determine which practices to follow. These are selected and documented as PGE cybersecurity controls.

e) OPUC Staff Question

Is PGE enacting any Company-wide practices or policies that set it above industry standards?

f) PGE's Response

In general, PGE evaluates all practices defined in standards and selects the practices that reduce our risks, respond to threats or meet regulations as appropriate. Some of these practices are above industry standards such as CIP and others are not. A more detailed answer to this could be provided to Staff as part of PGE's annual cybersecurity update provided to OPUC.

VII. Research and Other Projects

a) OPUC Staff Question (Order No. 15-314 Requirement #5)[14]

Does PGE have a timeline for ongoing collaborative work with PNNL?

b) PGE's Response

PNNL will model doable use cases by the end of the year and begin optimization work in Q4 2016/Q1 2017.

c) OPUC Staff Question (Order No. 15-314 Requirement #9)[15]

Amongst a number of purposes, Staff views the Smart Grid Reports as a central hub for reporting any smart-grid related efforts occurring in other dockets. Staff requests that PGE continue this purpose as it pertains to non-wire alternatives by documenting updates that occur across smart grid activities, including those in the UM 1751, microgrid, Conservation Voltage Reduction (CVR), and demand response. Specific, pertinent details relating to these topics that otherwise would not be reported in their respective sections in the Smart Grid Report should be reported under the non-wire section in future reports.

d) PGE's Response

PGE recognizes the Smart Grid Report as a central hub for reporting smart-grid related efforts. However, PGE believe that pertinent details related to specific topics (i.e. CVR) would best be reported in their respective sections of the report. The 'non-wire' section in the Smart Grid Report refers to a specific research project in collaboration with PSU.

e) OPUC Staff Comment (Order No. 15-314 Requirement #9)

Staff would like PGE to further explain the purpose of the paper/report it plans to coordinate with PSU and explain generally what it will contain.

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[14] Staff's Comments at p. 4.
[15] Staff's Comments at p. 5.

f) <u>PGE's Response</u>

PSU's project proposal is provided in Attachment E. The project has not yet been funded.

VIII. Conclusion

PGE believes the 2016 Smart Grid Report filing has met the requirements established by previous Commission Orders[16] and requests the Commission to accept this report. PGE greatly appreciates the input and collaboration of Staff and other stakeholders on this report. PGE looks forward to continued collaboration around future reports and smart grid development in Oregon.

Dated this 26th day of August, 2016

Patrick G Hager for

Stefan Brown
Manager, Regulatory Affairs
Portland General Electric
121 SW Salmon Street, 1WTC0306
Portland, OR 97204
503.464.8937

[16] See Commission Order No. 12-158 established in Docket No. UM 1460 and Commission Order No. 15-314 established in Docket No. UM 1657.

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

July 31, 2012

Via Email
vikie.malkasian@state.or.us

Vikie Malkasian
Administrator
550 Capitol Street, N.E., Ste 215
PO Box 2148
Salem, OR 97308-2148

RE: **AMI Operational Savings Report**

Commission Order No. 08-245 (Docket No. UE 189) approved PGE's advanced metering infrastructure (AMI) program and adopted certain conditions as part of that approval (see Appendix A, pages 10-21). One condition requires that if PGE "does not file a general rate case within 12 months of the termination of the UE 189 tariffs, PGE will provide Staff and any interested party a report showing final capture of O&M savings so that the comparison of 'before' and 'after' states does not become too difficult."

On July 19, 2011, the OPUC Staff, the Citizens' Utility Board, and PGE agreed to change the time period of the AMI Operational Savings Report from the 2011 calendar year to two semi-annual reports: the first covering July 2011-December 2011, and the second covering January 2012-June 2012. Pursuant to this agreement and Order No. 08-245, PGE provides the attached AMI Operational Savings Report for the half-year ending December 31, 2011. (The spreadsheet and work papers are provided in electronic format only.)

If you have any questions or require further information, please call Alex Tooman at (503) 464-7623. Please direct all formal correspondence and requests to the following email address: pge.opuc.filings@pgn.com.

Sincerely,

Patrick G. Hager
Manager, Regulatory Affairs

PGH:jlt
cc: UE 189 Service List

PGE

AMI Operational Savings Report

(July 1, 2011 to December 31, 2011)

Introduction

Commission Order No. 08-245 (Docket No. UE 189) approved PGE's advanced metering infrastructure (AMI) program and adopted certain conditions as part of that approval (see Appendix A, pages 10-21). One condition requires that if PGE "does not file a general rate case within 12 months of the termination of the UE 189 tariffs, PGE will provide Staff and any interested party a report showing final capture of O&M savings so that the comparison of 'before' and 'after' states does not become too difficult." PGE did not file a general rate case in 2011, and thus provides this report.

If all aspects of AMI had been completed by December 31, 2010, as originally scheduled, calendar year 2011 would have been the first full year after completing AMI deployment. However, due to certain delays related to implementing IT process improvements, the AMI project close-out did not occur until June 30, 2011. Thus, many operational savings were not available until the second half of 2011.

On July 19, 2011, the OPUC Staff, the Citizens' Utility Board, and PGE (the Parties) agreed to change the time period of the AMI Operational Savings Report from the 2011 calendar year to two semi-annual reports: the first covering July 2011-December 2011 and the second covering January 2012-June 2012. For the purpose of comparison and savings calculation, the Parties agreed that calendar year 2007, escalated to 2011 for known cost increases, provides the appropriate baseline for establishing AMI project savings. Pursuant to this agreement and Order No. 08-245, PGE provides the following AMI Operational Savings Report for the half-year ending December 31, 2011.

Summary

Table 1, below, summarizes the net actual AMI Operational Benefits for the six-month period of July 2011 through December 2011:

Table 1, Summary of AMI Net Operational Benefits Jul-Dec 2011	
Category	**$**
Operational Benefits	
FTE reductions - straight time	4,220,273
Other labor/contractor reductions	109,878
Overtime reductions	239,142
Material and supplies	176,358
Fuel and maintenance	381,842
Late pay fees	861,135
Load forecast adjustment from UE 215 to reflect remote disconnects	333,689
Additional billings from lost revenue protection	856,777
Meter accuracy	780,737
Subtotal	**7,959,831**
Additional benefits	
Currently unavailable due to power price decrease	393,174
Outage management (i.e., pinging the meter)	203,781
Business Energy Tax Credits (BETCs)	193,770
UE 215 stipulated benefit	219,058
Gross AMI Benefits	**8,969,615**
Other Incremental Costs	
Non-Labor IT costs	(153,404)
Non-Labor communication costs	(111,257)
Non-Labor network data operations	-
Net AMI Benefits (for six months, July-Dec 2011)	**8,704,954**
Annualized AMI Benefits (based on the July-Dec 2011 period)	**17,409,908**
Projected Benefits – 2012	
Forecasted benefits – additional FTE reductions in 2012	1,391,685
Projected Annualized AMI Benefits 2012	**18,801,593**

Operational Benefits

FTE Reductions – Straight Time

Overall, PGE realized approximately 113.2 FTE reductions directly related to AMI deployment by 2011. By taking the average salary for each department and multiplying by their respective FTE reductions or additions, a savings of approximately $2.6 million in straight time labor was calculated. With the addition of labor loadings, FTE reductions accounted for approximately $4.2 million in operational benefits between July and December 2011.

Other Labor/Contractors

In PGE's Billing Department, commitments were made to reduce straight-time Labor FTEs (incorporated in above FTE reductions) as well as contractors. Between the 2007 baseline year and 2011, the Billing Department realized approximately 4.5 contractor reductions directly related to AMI deployment. These reductions accounted for approximately $0.110 million in operational benefits between July and December 2011.

Overtime

From the reductions in meter readers, there has been a corresponding reduction in overtime costs associated with meter reading. By comparing baseline 2007 overtime costs to 2011, PGE calculated that overtime reductions accounted for approximately $0.239 million in operational benefits between July and December 2011.

Materials and Supplies

From the reductions in meter readers, there has been a corresponding reduction in materials and supplies cost in the Meter Reading Department. By comparing baseline 2007 materials and supplies costs to 2011, PGE calculated that materials and supplies costs accounted for approximately $0.176 million in operational benefits between July and December 2011.

Fuel and Maintenance

With AMI fully deployed, there has been a corresponding reduction in fuel and automotive costs associated with meter reading. By escalating the baseline 2007 vehicle fuel and maintenance costs the benefits for fuel and maintenance reductions is determined. For the first six months AMI was fully deployed, reductions in fuel and maintenance costs accounted for approximately $0.382 million in operational benefits.

Late Pay Fees

One of the significant qualitative benefits of AMI is the ability for customers to select their preferred billing cycle, so that their bill due date is more convenient. With the provision of this benefit, the Oregon administrative rules allow PGE to advance by approximately 30 days the date when customers are obligated to pay a late fee on past-due bills. By comparing the baseline 2007 Late Payment Fees to 2011, we determined that Late Pay Fees accounted for approximately $0.861 million in operational benefits between July and December 2011.

Load Forecast Adjustment

In Docket No. UE 215, PGE's 2011 general rate case, we adjusted the residential load forecast by (20,411) MWhs to reflect the reduction in energy use that PGE would achieve from its remote disconnect meters. Because the expected reduction in arrearages has been obscured by the continued weakness in the Oregon economy, we cannot quantitatively establish this benefit from 2011 data. PGE has nevertheless maintained the load reduction to provide this benefit to customers. In UE 189, this benefit was estimated to be $1.4 million with avoided energy costs priced at approximately $66/MWh. In UE 215, when we applied the load reduction, energy costs had declined to approximately $51/MWh, so that of the $1.4 million energy-related benefit, $0.3 million were based on "power prices ... beyond PGE's control, we note this aspect of energy-related benefits as being temporarily unavailable but in the future, it is fully achievable." (See PGE Exhibit 300, page 17.) In 2011, energy prices have declined further to approximately $30/MWh. Consequently, the load reduction benefit is $0.334 million between July and December 2011 and the temporarily unavailable component of this energy-related benefit is $0.393 million for half year period.

Additional Billings from Lost Revenue Protection

With AMI, PGE's Energy Recovery Department has been able to use newly acquired interval data to increase their success in the identification of energy theft and unaccounted for energy losses (i.e., lost revenue protection or LRP). By comparing the baseline 2007 "lost MWh avoided" to 2011, PGE identified an increase of approximately 8,605 MWh of energy loses that were avoided due to AMI. This accounts for approximately $0.857 million in energy-related savings between July and December 2011.

Meter Accuracy

In conjunction with AMI deployment, PGE performed a study to estimate the improvement in meter accuracy between old mechanical meters and new solid state meters. The purpose of the study was to evaluate the new meters' ability to read lower levels of consumption and to correct for older mechanical meters running slower over time. From the study, PGE calculated an operational benefit of approximately $0.781 million.

Additional Benefits

Currently Unavailable due to Power Price Decrease

As noted above, the decline in power prices has increased the amount of currently unavailable energy-related benefits associated with the UE 215 load forecast adjustment. For the July through December 2011 period, this totals $0.393 million.

Outage Management

One of the benefits of AMI is the ability for PGE's repair and line dispatchers to "ping" the meters. Pinging the meter allows PGE to determine whether or not a meter has power without the need for a repair or line dispatcher to dispatch a crew. By comparing the average non-dispatch cost savings from 2007-2010 to the non-dispatch cost savings in 2011, we determined that pinging the meter accounted for approximately $0.204 million in operational benefits between July and December 2011.

Business Energy Tax Credits (BETCs)

In UE 215, PGE's revenue requirement reflected $1.0 million in state tax credits for BETC's associated with AMI. Based on the Oregon Dept. of Energy's preliminary approval, the BETCs were expected to total $3.5 million and be available over five years as follows:

2011	$1,000,000
2012	$1,000,000
2013	$500,000
2014	$500,000
2015	$500,000

Because PGE did not receive final approval of the BETCs until 2012, customers will receive the $1.0 million tax credit benefit for at least three years and until PGE's next rate case goes into effect. By calculating the levelized, net present value of the BETC revenue requirement, we identify approximately $0.194 million in operational benefits between July and December 2011.

UE 125 Stipulated Benefit

In UE 215, PGE stipulated to provide customers with an additional $1.7 million reduction to O&M costs (see Commission Order 10-478, Appendix A, page 3). PGE customers will therefore receive this benefit until January 1, 2014, which is the earliest a new general rate case could go into effect. By calculating the levelized, net present value of the O&M reduction revenue requirement, we identify approximately $0.219 million in operational benefits between July and December 2011.

Other Incremental Costs

Non-Labor IT Costs

The incremental Non-Labor IT costs reflect an increase in network and server infrastructure, annual Oracle support and maintenance licensing, and storage to cover the availability requirements for Meter Data Consolidator (MDC). The incremental Non-Labor IT costs between July and December 2011 are approximately $0.153 million.

Non-Labor Communication Costs

The incremental Non-Labor Communication costs reflect the regulatory requirement that PGE perform outbound calls to customers that PGE remotely disconnects. PGE contracts with a third party vendor to perform outbound calls to meet the regulatory requirement. The incremental Non-Labor Communication costs between July and December 2011 were approximately $0.111 million.

Non-Labor Network Data Operations

The incremental costs in Non-Labor Network Data Operations that reflect the annual support payments for Tower Gateway Basestation (TGB) maintenance, Regional Network Interface (RNI) software, and Radio Frequency licensing are zero because they are covered by credits received from PGE's meter vendor.

Conclusion

In UE 189, PGE estimated that the AMI operational benefits would be approximately $18.2 million in 2011 (the final UE 189 estimate was filed in November 2007). After six months (July 2011 to December 2011) of AMI being fully deployed, PGE has accounted for approximately $8.7 million in actual operational benefits. On an annualized basis, this equals $17.4 million, which is $0.8 million less than the estimate developed in 2007. Looking forward, however, PGE has achieved additional AMI-related reductions of 8 FTEs by June 30, 2012 and we expect to reduce an additional 7 FTEs by year-end 2012. At fully-loaded, average wages these FTEs are expected to produce an additional $1.4 million benefit, which would raise the annualized benefit total to $18.8 million.

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CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the foregoing **AMI OPERATIONAL SAVINGS REPORT: JULY 2011 -- DECEMBER 2011** to be served by electronic mail to those parties whose email addresses appear on the attached service list, and by First Class US Mail, postage prepaid and properly addressed, to those parties on the attached service list who have not waived paper service for OPUC Docket No. UE 189.

DATED at Portland, Oregon, this 31st day of July, 2012.

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November 2, 2012

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RE: **AMI Operational Savings Report**

Commission Order No. 08-245 (Docket No. UE 189) approved PGE's advanced metering infrastructure (AMI) program and adopted certain conditions as part of that approval (see Appendix A, pages 10-21). One condition requires that if PGE "does not file a general rate case within 12 months of the termination of the UE 189 tariffs, PGE will provide Staff and any interested party a report showing final capture of O&M savings so that the comparison of 'before' and 'after' states does not become too difficult."

On July 19, 2011, the OPUC Staff, the Citizens' Utility Board, and PGE agreed to change the time period of the AMI Operational Savings Report from the 2011 calendar year to two semi-annual reports: the first covering July 2011-December 2011, and the second covering January 2012-June 2012. Pursuant to this agreement and Order No. 08-245, PGE provides the attached AMI Operational Savings Report for the half-year ending June 30, 2012. (The spreadsheet and work papers are provided in electronic format only.)

If you have any questions or require further information, please call Alex Tooman at (503) 464-7623. Please direct all formal correspondence and requests to the following email address: pge.opuc.filings@pgn.com.

Sincerely,

Patrick G. Hager
Manager, Regulatory Affairs

PGH:jlt
cc: UE 189 Service List

PGE

AMI Operational Savings Report

(January 1, 2012 to June 30, 2012)

Introduction

Commission Order No. 08-245 (Docket No. UE 189) approved PGE's advanced metering infrastructure (AMI) program and adopted certain conditions as part of that approval (see Appendix A, pages 10-21). One condition requires that if PGE "does not file a general rate case within 12 months of the termination of the UE 189 tariffs, PGE will provide Staff and any interested party a report showing final capture of O&M savings so that the comparison of 'before' and 'after' states does not become too difficult." PGE did not file a general rate case in 2011, and thus provides this report.

If all aspects of AMI had been completed by December 31, 2010, as originally scheduled, calendar year 2011 would have been the first full year after completing AMI deployment. However, due to certain delays related to implementing IT process improvements, the AMI project close-out did not occur until June 30, 2011. Thus, many operational savings were not available until the second half of 2011.

On July 19, 2011, the OPUC Staff, the Citizens' Utility Board, and PGE (the Parties) agreed to change the time period of the AMI Operational Savings Report from the 2011 calendar year to two semi-annual reports: the first covering July 2011-December 2011 and the second covering January 2012-June 2012. For the purpose of comparison and savings calculation, the Parties agreed that calendar year 2007, escalated to 2011 for known cost increases, provides the appropriate baseline for establishing AMI project savings.

On July 31, 2012, PGE provided its first semi-annual report, covering July 2011-December 2011. After those six months, PGE accounted for approximately $8.7 million in actual operational benefits. On an annualized basis, that equaled $17.4 million.

Pursuant to PGE's agreement with Parties and Order No. 08-245, PGE provides the second semi-annual AMI Operational Savings Report for the half-year ending June 30, 2012.

Summary

Table 1, below, summarizes the net actual AMI Operational Benefits for the six-month period of January 2012 through June 2012:

Table 1, Summary of AMI Net Operational Benefits Jan-Jun 2012	
Category	**$**
Operational Benefits	
FTE reductions - straight time	5,068,904
Other labor/contractor reductions	100,427
Overtime reductions	203,337
Material and supplies	275,836
Fuel and maintenance	391,596
Late pay fees	1,115,724
Load forecast adjustment from UE 215 to reflect remote disconnects	309,144
Additional billings from lost revenue protection	473,771
Meter accuracy	780,737
Subtotal	8,719,475
Additional benefits	
Currently unavailable due to power price decrease	417,720
Outage management (i.e., pinging the meter)	205,531
Business Energy Tax Credits (BETCs)	193,770
UE 215 stipulated benefit	219,058
Gross AMI Benefits	9,755,554
Other Incremental Costs	
Non-Labor IT costs	(156,161)
Non-Labor communication costs	(119,082)
Non-Labor network data operations	-
Net AMI Benefits (for six months, Jan - Jun 2012)	**9,480,311**
Annualized AMI Benefits (based on the Jan - Jun 2012 period)	**18,960,622**
Projected Benefits – 2012	
Forecasted benefits – additional FTE reductions in 2012	398,215
Projected Annualized AMI Benefits 2012	**19,358,837**

Operational Benefits

FTE Reductions – Straight Time

Overall, PGE realized approximately 122 FTE reductions directly related to AMI deployment by end of June 2012. By taking the average salary for each department and multiplying by their respective FTE reductions or additions, a savings of approximately $3.0 million in straight time labor was calculated. With the addition of labor loadings, FTE reductions accounted for approximately $5.0 million in operational benefits between January and June 2012.

Other Labor/Contractors

In PGE's Billing Department, commitments were made to reduce straight-time Labor FTEs (incorporated in above FTE reductions) as well as contractors. Between the 2007 baseline year and 2012, the Billing Department realized approximately 4.5 contractor reductions directly related to AMI deployment. These reductions accounted for approximately $0.100 million in operational benefits between January and June 2012.

Overtime

From the reductions in meter readers, there has been a corresponding reduction in overtime costs associated with meter reading. By comparing baseline 2007 overtime costs to 2012, PGE calculated that overtime reductions accounted for approximately $0.203 million in operational benefits between January and June 2012.

Materials and Supplies

From the reductions in meter readers, there has been a corresponding reduction in materials and supplies cost in the Meter Reading Department. By comparing baseline 2007 materials and supplies costs to 2012, PGE calculated that materials and supplies costs accounted for approximately $0.276 million in operational benefits between January and June 2012.

Fuel and Maintenance

With AMI fully deployed, there has been a corresponding reduction in fuel and automotive costs associated with meter reading. By escalating the baseline 2007 vehicle fuel and maintenance costs the benefits for fuel and maintenance reductions is determined. For the six-month time period of January 2012 through June 2012, reductions in fuel and maintenance costs accounted for approximately $0.392 million in operational benefits.

Late Pay Fees

One of the significant qualitative benefits of AMI is the ability for customers to select their preferred billing cycle, so that their bill due date is more convenient. With the provision of this benefit, the Oregon administrative rules allow PGE to advance by approximately 30 days the date when customers are obligated to pay a late fee on past-due bills. By comparing the baseline 2007 Late Payment Fees to 2012, we determined that Late Pay Fees accounted for approximately $1.1 million in operational benefits between January and June 2012.

Load Forecast Adjustment

In Docket No. UE 215, PGE's 2011 general rate case, we adjusted the residential load forecast by (20,411) MWhs to reflect the reduction in energy use that PGE would achieve from its remote disconnect meters. Because the expected reduction in arrearages has been obscured by the continued weakness in the Oregon economy, we cannot quantitatively establish this benefit from 2012 data. PGE has nevertheless maintained the load reduction to provide this benefit to customers. In UE 189, this benefit was estimated to be $1.4 million with avoided energy costs priced at approximately $66/MWh. In UE 215, when we applied the load reduction, energy costs had declined to approximately $51/MWh, so that of the $1.4 million energy-related benefit, $0.3 million were based on "power prices… beyond PGE's control, we note this aspect of energy-related benefits as being temporarily unavailable but in the future, it is fully achievable." (See PGE Exhibit 300, page 17.) In 2012, energy prices have declined further to approximately $27.96/MWh. Consequently, the load reduction benefit is $0.309 million between January and June 2012 and the temporarily unavailable component of this energy-related benefit is $0.418 million for half year period.

Additional Billings from Lost Revenue Protection

With AMI, PGE's Energy Recovery Department has been able to use newly acquired interval data to increase their success in the identification of energy theft and unaccounted for energy losses (i.e., lost revenue protection or LRP). By comparing the baseline 2007 "lost MWh avoided" to 2012, PGE identified an increase of approximately 9,636 MWh of energy loses that were avoided due to AMI. This accounts for approximately $0.474 million in energy-related savings between January and June 2012.

Meter Accuracy

In conjunction with AMI deployment, PGE performed a study to estimate the improvement in meter accuracy between old mechanical meters and new solid state meters. The purpose of the study was to evaluate the new meters' ability to read lower levels of consumption and to correct for older mechanical meters running slower over time. From the study, PGE calculated an operational benefit of approximately $0.781 million for the half-year period.

Additional Benefits

Currently Unavailable due to Power Price Decrease

As noted above, the decline in power prices has increased the amount of currently unavailable energy-related benefits associated with the UE 215 load forecast adjustment. For the January through June 2012 period, this totals $0.418 million.

Outage Management

One of the benefits of AMI is the ability for PGE's repair and line dispatchers to "ping" the meters. Pinging the meter allows PGE to determine whether or not a meter has power without the need for a repair or line dispatcher to dispatch a crew. By comparing the average non-dispatch cost savings from 2007-2010 to the non-dispatch cost savings in 2012, we determined that pinging the meter accounted for approximately $0.206 million in operational benefits between January and June 2012.

Business Energy Tax Credits (BETCs)

In UE 215, PGE's revenue requirement reflected $1.0 million in state tax credits for BETC's associated with AMI. Based on the Oregon Dept. of Energy's preliminary approval, the BETCs were expected to total $3.5 million and be available over five years as follows:

2011	$1,000,000
2012	$1,000,000
2013	$500,000
2014	$500,000
2015	$500,000

Because PGE did not receive final approval of the BETCs until 2012, customers will receive the $1.0 million tax credit benefit for at least three years and until PGE's next rate case goes into effect. By calculating the levelized, net present value of the BETC revenue requirement, we identify approximately $0.194 million in operational benefits between January and June 2012.

UE 215 Stipulated Benefit

In UE 215, PGE stipulated to provide customers with an additional $1.7 million reduction to O&M costs (see Commission Order 10-478, Appendix A, page 3). PGE customers will therefore receive this benefit until January 1, 2014, which is the earliest a new general rate case could go into effect. By calculating the levelized, net present value of the O&M reduction revenue requirement, we identify approximately $0.219 million in operational benefits between January and June 2012.

Other Incremental Costs

Non-Labor IT Costs

The incremental Non-Labor IT costs reflect an increase in network and server infrastructure, annual Oracle support and maintenance licensing, and storage to cover the availability requirements for Meter Data Consolidator (MDC). The incremental Non-Labor IT costs between January and June 2012 are approximately $0.156 million.

Non-Labor Communication Costs

The incremental Non-Labor Communication costs reflect the regulatory requirement that PGE perform outbound calls to customers that PGE remotely disconnects. PGE contracts with a third party vendor to perform outbound calls to meet the regulatory requirement. The incremental Non-Labor Communication costs between January and June 2012 were approximately $0.119 million.

Non-Labor Network Data Operations

The incremental costs in Non-Labor Network Data Operations that reflect the annual support payments for Tower Gateway Basestation (TGB) maintenance, Regional Network Interface (RNI) software, and Radio Frequency licensing are zero because they are covered by credits received from PGE's meter vendor.

Conclusion

In UE 189, PGE estimated that the AMI operational benefits would be approximately $18.2 million in 2011 and $18.9 million in 2012 (the final UE 189 estimate was filed in November 2007). During the six-month time period (January 2012 to June 2012) with AMI fully deployed, PGE has accounted for approximately $9.5 million in actual operational benefits. On an annualized basis, this equals $19.0 million. Looking forward, PGE expects to reduce an additional 4 FTEs by year-end 2012. At fully-loaded, average wages these FTEs are expected to produce an additional $0.4 million benefit, which would raise the annualized benefit total to $19.4 million.

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CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the foregoing **AMI OPERATIONAL SAVINGS REPORT: JANUARY – JUNE 2012** to be served by electronic mail to those parties whose email addresses appear on the attached service list, and by First Class US Mail, postage prepaid and properly addressed, to those parties on the attached service list who have not waived paper service for OPUC Docket No. UE 189.

DATED at Portland, Oregon, this 2nd day of November, 2012.

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Draft PGE Scoping Plan for AMI Benefits

I. Introduction

In PGE's most recent general rate case, OPUC Docket No. UE 180 (see PGE Exhibits 800, 2300, and 3000), PGE submitted a proposal for an advanced metering infrastructure (AMI) system. As we explained in the March 2006 filing that initiated that docket: "PGE believes now is the appropriate time to launch an AMI project because the technology is mature and a number of parties have signaled their interest in moving forward with future methods of grid management and demand response. We cannot begin to achieve these goals without AMI." PGE Exhibit 800 at 3. These reasons are even more compelling now. Since March 2006, initial results from our current Integrated Resource Planning (IRP) process indicate that PGE will need to acquire approximately 900 MW of capacity by 2012. Demand-side resource can and should play a significant role in filling this need. Demand-side programs not only help ease pressure on PGE's electric delivery system during peak load times and reduce the risk of interruptions during extreme peaks but, importantly, participating customers reduce their electric bills and save money. No other resource can save customers money as we deploy it. PGE is very interested in demand-side benefits and we are confident that the AMI system we propose will support them. We do not expect implementing demand-side programs to require complicated connections with the information platform because, from 2000 through 2003, PGE had already developed much of the IT software and system integration needed to operate a fully functioning AMI system.

As we began this project in 2005, we initially focused on the operational effects and benefits of changing how we meter customers' usage. We needed to manage the change well, and sound business practices required that we identify and capture what benefits we could as we made the necessary process changes. Pursuant to Staff's requests (in Staff Exhibit 700), we have started and/or completed implementation plans for those changes and benefits that stem from the change in technology. With this document, we add to it our scoping plans for achieving the customer- and system-related benefits that moving to metering grounded in two-way, real-time communication – rather than a monthly manual read – will enable. These fall into the categories of:

- Demand response programs.
- Information-driven energy savings.
- Improved distribution asset utilization.
- Improved outage management.

In 2007, we will develop implementation plans for these benefit categories.

Using the current system cost estimate of approximately $132.2 million, we anticipate $18.2 million in annual cost savings from operational benefits in 2011, after the system is fully deployed. These costs and benefits produce a net present value benefit of approximately $34 million over 20 years of system operation. With the benefits identified in this scoping plan, we estimate that the net present value benefit of deploying AMI now could increase to between $37 million to $80 million (see Attachment 1) depending on customer acceptance of demand-response initiatives and various other necessary assumptions.

II. Regulatory Status

Based on comments from the OPUC Staff and other parties, PGE agreed to remove AMI from UE 180 with the understanding that we would resubmit the proposal in a separate, non-rate case proceeding. This filing will encompass the accelerated depreciation of non-AMI meters and other NMR infrastructure that is no longer needed by the new system, plus the revenue requirement of the new AMI system less O&M savings throughout the deployment period.

To support this application, PGE agreed to submit the following documentation:

- A detailed implementation plan for the O&M benefits that PGE reasonably expects to achieve as we implement this technology change.
- A scoping plan for customer- and system-related benefits not covered in PGE's original financial analysis. Our proposed AMI system enables or supports these benefits , but most require additional costs or investment .

PGE is submitting the detailed implementation plan for primary benefits in conformance with the description provided in UE 180, Staff Exhibit 700. The scoping plan below includes the following information:

- The benefit categories that PGE will pursue based upon highest perceived benefit versus cost.
- A timetable for implementation plans.
- A range of potential benefits for the specified programs.

During 2007, PGE will develop implementation plans for the specified benefit categories of this scoping plan.

III. Customer- and System-Related Benefits

In accordance with PGE Exhibit 3000 (OPUC Docket UE 180), PGE submits this scoping plan to support its proposal for an AMI system. This scoping plan addresses the following broadly defined AMI benefit categories:

- Demand response initiatives
- Energy savings prompted by the availability of hourly usage data
- Improved distribution planning
- Improved outage management

Estimating the net benefits of these initiatives is more challenging than with the operational changes because most require additional investment or cost and some entail customer acceptance as a key variable. Where possible, we drew on industry standards and experience, but this is limited and requires that we consider differences among utilities in general. The accompanying spreadsheet documents the calculations for the more complicated estimates. We have provided ranges estimates because, as noted below, typically the most sensitive variables that determine the benefit value depend on either data not yet collected at PGE or on customer acceptance of new programs. Also provided below are the basic assumptions PGE used to estimate the net benefits for specific sub-category initiatives. These subcategories will be the focus for subsequent implementation plans.

Demand Response

PGE has a strong interest in demand response. A successful demand response program would further the company objectives of reducing generation supply costs and increase options for customers to control their monthly electricity bills. Because PGE needs to acquire, approximately 900 MW of capacity, as identified during IRP planning, we fully recognize demand response as a potential means to supply some of this peak capacity. In addition, AMI-supported demand response programs would be an invaluable resource during the next possible "energy crisis." Many regulators and utilities undoubtedly wished that AMI systems had been in place during the energy crisis of 2001-2002. While a subsequent energy crisis is currently unforeseen and would undoubtedly occur for different reasons, the possibility exists and could occur both rapidly and unexpectedly. If so, AMI systems, and demand response programs in particular, could either help mitigate the effects or be wished for yet again.

Outside of PGE there is a considerable interest in demand response from federal departments and many state regulators. However, as discussed in most regulatory and industry trade meetings on this subject, there is considerable uncertainty in the possible outcomes from program implementation. Typical topics for debate include:

- What is the likely interest among customers?
- How do we encourage high levels of participation?
- What amount of demand shift will customers provide?
- What is the best way to design rates?
- How should we value the benefits of the demand that is shifted?

What are no longer discussed are the requirements for an AMI system to support these programs. PGE's proposed AMI system will provide robust support for future program design.

PGE has been fully engaged in a number of these regulatory and industry forums, in some cases providing leadership for defining the necessary changes. Two overarching conclusions can be drawn from these meetings and these pertain to PGE also.

1. For demand response to be successful, the industry needs to gain experience in implementing, promoting, operating, and evaluating these programs.
2. To participate in a meaningful way, most customers will need major appliances that respond automatically and effectively by receiving utility control and/or price signals directly.

Based on these conclusions, PGE's near term actions will be to develop implementation plans to address the two needs. The first effort will be a plan for a demand response market pilot, and the second, a plan for a market transformation initiative based on the lessons learned from PGE's participation in the NW Grid-Friendly Appliance (GFA) project. While these plans look feasible, cost effectiveness depends – as is always the case – on assumptions that future conditions may cause to change.

Demand Response Market Pilot

At present, we plan an Opt-In, Critical Peak Pricing (CPP) Tariff Pilot for 2009 implementation, targeted at residential customers, with one-time development costs of approximately $1 million in 2008 and 2009. After launching in 2009, our effort would be to reach the maximum participation rate by 2013, with a total of twenty critical-peak price events during the winter and summer. By 2013, we would evaluate and engage in any necessary program re-design to maintain the acceptance rate.

Attachment 2 to this document provides a simple model that includes most of the costs of the program. The model is simple so as to emphasize the sensitivity to three variables that correspond to the chief uncertainties: the number of customers that participate, the average kW load shift per customer, and the value of capacity.

To explore the range of possible benefits, we created a nominal scenario, a low scenario and a high scenario. The range of net present values for the three scenarios varies between a negative value and $27 million dollars. The duration of the program is coincident with the life of the AMI system. Note that $27 million occurs in the high scenario with an assumption of only 10% market penetration. We used this assumption because few opt-in programs at PGE have participation as high as 10%. Changes in societal energy interests, however, could drive a much higher acceptance rate and the benefits would increase accordingly. The following variables represent the primary assumptions used in Attachment 2:

Customer Participation
The single biggest uncertainty is customer participation rate. In the nominal case, we assume participation reaches 5% (about 40,000 customers.) In the low case we assume 1.5% acceptance and 10% in the high case. The specific elements of the rate design (and its associated terms), customer education efforts, and how effectively the offer is promoted will likely significantly affect program acceptance. A break-even result requires the fairly large participation of the Low Scenario because of the one-time startup cost of approximately $1 million

Load Shift
The nominal average value of 0.5 KW shifted per customer is based on PGE's Analysis of the Load Impacts and Economic Benefits of the Residential TOU Rate Option section on CPP. Because this estimate is not based on experience in PGE's service territory, actual results could vary considerably. The Low Scenario assumes 75% of this value and the High Scenario 140%.

Avoided Capacity Cost
The primary benefit driver is the cost of avoided capacity. Again, with almost no industry experience with CPP programs the appropriate value to associate with capacity is difficult to estimate. One alternative is the annual cost associated with a simple cycle combustion turbine (CT). In PGE's IRP, this value is more than $70/kW per year. We believe this avoided cost may

be high, however, for two reasons. First, at least in the recent past, PGE has found capacity resources that cost less than this. Second, there are no restrictions on how many hours a CT provides capacity and a CT provides reactive current support to the transmission grid during peak periods. Gauging from this avoided cost, we used a value of $29 per KW-year in the Low Scenario because this is what we have incurred, to date, to implement resources for PGE's distributed generation program. In the Nominal Scenario we assume a value of $36 per KW-year and $58 in the High Scenario.[1]

Appliance Market Transformation[2]

The residential sector accounts for approximately 25% of PGE's winter system peak demand, from a combination of water/space heating, cooking, refrigeration and lights. Hourly price signals sent to customers might motivate a substantial shifting of this load to less expensive off-peak hours without significant inconvenience to customers, particularly if the decision how and when to participate could be made just once in appliance set-up. Three market barriers presently exist. First, customers are frequently not at home to manage the load when the price signal is sent. Second, the cost to operate individual appliances (much less the knowledge and the ability to change how the appliance operates) is not well understood by customers. Third, electricity is a low involvement product; most consumers of electricity rarely think about it and tend to take it for granted. The solution to this problem is to have appliance manufacturers modify their appliances to (1) "hear" price and/or control signals from the utility, and (2) include a simple control at the appliance so the customer can make a one-time decision about how much of the appliance function they are willing to give up when the price of electricity is high. Having put those elements into place, the actual load shifting would be an automated function triggered by utility price signals. This is the "smart appliance" concept.

Our plan is to define a technology trial for either water heaters or thermostats whereby a consortium consisting of PGE, our AMI vendor, an appliance or thermostat manufacturer, and other interested parties[3] develop a project to create a 10 MW demand response resource by decreasing the installed cost per kW through an appliance market-transformation approach. As suggested above, the components of a smart appliance demand response system include (a) a communications-ready appliance, (b) a communications device[4], and (c) a communications method between the customer (or appliance) and the utility (e.g., AMI network).

In the end state of appliance market transformation, the incremental cost to develop a communication-ready appliance is expected to be about $2 to $5 per appliance.[5] When sufficient

[1] These avoided cost values are for illustrative purposes and not intended to be indicative of PGE's avoided cost under the Public Utility Regulatory Policies Act.
[2] While the examples that follow focus on price responsive programs, PGE intends to review direct load control opportunities in our implementation plan for demand response as well. Direct load control will also be addressed in PGE's IRP.
[3] E.g. Pacific Northwest National Lab, Bonneville Power Administration, Oregon Department of Energy (ODOE), Northwest Power Planning Council, US DOE, etc.
[4] This would be an after-market, low-cost communication device that would pass price and/or load control signals after plugging the device into the appliance, much like inserting a WiFi device into a computer USB socket.
[5] For the technology trial described here, the estimated cost to get these appliances into the home is almost $100 per water heater. This is because no communication-ready standard for appliances exists today. In addition to a higher appliance cost, marketing costs must be incurred to get the appliances into the home.

numbers of such appliances exist, the utility can implement a very cost-effective program simply by mailing communication devices to those customers who choose to participate. Also in the end state, we estimate the communication device to cost between $0 and $20 depending on what communication resources already exist in the home. (At the lower volume of the demonstration, a $40 cost is expected.)

The main objectives of the technology trial are to:

- Prove the concept of a communication-ready appliance to further the goal of a national standard in this area
- Demonstrate a program where control implementation is achieved by providing only communication devices after sufficient appliances are available to warrant the launch of the program.
- Create a technology-assisted, 10 MW demand response capability.
- Demonstrate that the installed cost per controllable kW is greatly reduced through market transformation.

The milestones in this project are to:

- Make available from the usual retail sources new, communication-ready thermostats or water heaters for use in new construction and replacement applications.
- Promote the selection of these appliances through standard program techniques.
- Promote and install a communication device (one most likely compatible with the AMI system) to allow the customer to capture automated-control benefits and reduce their energy costs under a time-of-use (TOU) or critical peak pricing (CPP) tariff. This will occur in the second or third year of marketing the program,

PGE's specific implementation plan for this initiative, which we will submit in 2007, will describe the following actions:

- Detail the costs, benefits, and timeline to implement the project outlined above.
- Explore membership interest in a consortium to demonstrate the smart appliance concept.
- Form the consortium if possible; otherwise, state barriers to formation.

Example Benefit/Cost Analysis[6]

We assume on-peak contribution of water heaters to be 0.85kW. To create a 10 MW resource, PGE customers must purchase approximately 15,000 "smart appliance" water heaters. We also assume 5,000 water heaters are sold in each of three (3) years—3,500 in the replacement market and 1,500 in new construction. An appliance manufacturer will need to contribute non-recurring engineering cost to the project. PGE will pay for incremental hardware cost at the appliance for an estimated $15 per water heater. PGE's marketing cost per water heater is estimated to be $60. In the second or third year, PGE would promote a direct load control and/or a TOU program to the customers owning these water heaters. To achieve an 80% participation rate, PGE might guarantee an annual bill savings to each customer. This amount, however, should have a near

[6] This example is for a communication-ready water heater; a thermostat trial would have very different results.

zero fulfillment cost, due to energy usage shifted away from on-peak. We estimate the customer-installable communication device to be approximately $40 apiece and other one-time program costs to be approximately $250,000. Consequently, we estimate the total installed capital cost to be approximately $1.6[7] million for a 10 MW resource or approximately $160/kW.

Without regard to the considerable societal benefits in this demonstration, PGE's annual net benefit on this 10 MW resource, compared to a supply side resource for capacity, varies between zero and $460,000 depending on the actual implementation costs and avoided capacity cost assumed. The details of this calculation are shown in Attached 2.

Information-Driven Energy Savings

PGE plans to conduct primary research on how to provide customers useful information from interval data. We also intend to develop an information tool based on the results of this research. We also expect this tool to support Customer Service Representatives (CSRs) in their work on behalf of customers.

PGE's hypothesis is that the information tool will reveal energy-reducing strategies that the customer finds valuable to implement. For example, the tool will determine the cost of running a "spare" refrigerator, or determine the bill reduction from reducing the thermostat setting by a few degrees. The tool might lead the customer to discover unnecessary, but always-on devices. These types of strategies could reduce total energy use by 1% to 10% annually. In a program aimed at getting 500 customers per week to use the tool, if 40% of the customers implement an average, 4-year sustained annual usage reduction of 2.5% (or about 250 kWh per year), then the typical year benefit after four (4) years would be about $500,000[8] per year. PGE estimates utility costs, including depreciation of the development and recurring annual costs to be approximately $110,000. Uncertainty exists with all variables implying a wide range in the benefit outcome. Sensitivity in the summary Table 1 is based on customer participation varying from -50% to +100%.

The main objectives of the project, by phase, will be:
Phase 1:

- Conduct primary research, develop concepts for information tool, and create requirements.
- Select a vendor suitable for PGE's objectives.
- Create the initial infrastructure to link meter information, an analysis engine, and a web interface for customers and CSRs.
- Focus on aiding the high-bill complaint process.
- Begin interval data collection for the initial customers that will test the Phase 2 information tool.

Phase 2:

[7] $1,600,000 = 15,000*(($60+$15) 0.8*$40)
[8] Based on an avoid energy cost of $50/MWh. 500,000 = $50/MWh * 4* (500 Customers/wk * 40% * 50 wk/yr * 250 kWh saved annual per customer)/1000. See Attachment 2 for calculation details.

- Develop a tool to help customers understand the cost drivers of daily appliance usage and their own behavioral choices.
- The tool will create semi-customized recommendations to save energy.
- Track energy use for customers that use the tool.
- Conduct an evaluation to determine if the information tool makes a sustained and quantifiable impact on the customer's energy use.

The milestones in this project are:
- Second quarter 2007 – Complete research and sign contract with vendor.
- Fourth quarter 2007 – Launch initial application for high-bill complaint process.
- Fourth quarter 2007 – Begin interval data collection for target group of 20,000 customers.
- Second quarter 2008 – Develop and test-launch interval-data dependent information tool.
- Third quarter 2008 – Test tool with customers and make improvements to usability.
- Fourth quarter 2008 – Launch information tool to target customers, with at least 8 months of interval data history. Promote tool sufficiently to get 1,000 participants in first 3 months.
- Third quarter 2009 – Conduct statistical analysis to determine impact of information tool on energy use.
- Fourth quarter 2009 – Make information tool available to all PGE customers.

Improved Distribution Asset Utilization

The underlying assumption in the topics discussed below is that the availability of hourly interval data at every point of delivery will allow PGE to compile a detailed load profile on each component of our distribution infrastructure (e.g., every tap line, service transformer, feeder segment between switches) with the objective of improving asset management and overall system efficiencies. Not included in these estimates is the cost to acquire an analysis tool, sufficiently powerful, to analyze the data.

<u>Avoided Service Transformer Failures</u>

PGE has approximately 300 service transformer failures per year, many of which result from overloading. PGE uses a regression tool to identify overloaded transformers based on estimated monthly kWh usage. The ability to collect interval data on 100% of PGE's service delivery points allows a new model to be developed based on actual hourly loadings which would enable PGE to identify transformers that are overloaded beyond normal tolerances on a more accurate and timely basis.

A new regression model could yield, for each service transformer, an estimate of peak loading (percent of nominal rating) as a function of the ambient temperature at the transformer. We estimate that a new tool might make it possible to eliminate as many as 30% of the failures (i.e., 90 transformers per year) before they occur. This would be especially useful given the increasing amount of home air–conditioning load being added by residential customers. With better data, transformers that are overloaded could be identified and replaced with new or higher-voltage transformers before they fail. This enables PGE not only to re-use the transformer at another location but also to be more efficient in planning and scheduling replacements.

To determine a potential benefit, we assume that the current cost to replace a failed service transformer is $500 plus a 3-man crew working two hours at an average cost of $315/hour (including overtime). This results in a cost of $1,130 per transformer. With a planned replacement, no overtime is required and several transformers can be exchanged per trip. Instead of a two-hour emergency replacement, the planned replacement is assumed to be a 1-hour event at an average cost of $270/hour instead of $315/hour. This results in an average savings of $860 per replaced transformer, or typical annual net savings of approximately $77,000 (90 * $860).

In addition, if we assume a reduced customer outage time of 3 hours, an average of four customers affected per transformer, and a $15/hour avoided societal cost per customer during the outage, the societal benefit is about $16,000 per year (90 replacements x 4 customers x 3 hours x $15/hour). Uncertainty in the 30% pre-identification rate puts total net benefit in the range of $40,000 to $200,000.

<u>Delayed Feeder Conductor Work</u>

PGE currently plans approximately $1 million of feeder conductor work per year. These are performed to resolve overloading conditions on sections of the affected feeder.

Assume that PGE defers one-third of its annual work to upgrade feeder conductors, an amount of $333,000, for three years because improved loading data were available from AMI. This is based on an engineering estimate. The estimated reduction in revenue requirement (using a 0.13 multiplier) on deferred hardware costs is approximately $43,000 per year. The additional engineering cost of collecting AMI data by conductor segment could be approximately $25,000 per year. Based on these assumptions, a net benefit can be achieved by year three and for ongoing years of approximately $100,000 per year (see table below).

Benefits	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Year 1 Work Deferred	$43,000	$43,000	$43,000	---	---
Year 2 Work Deferred	---	$43,000	$43,000	$43,000	
Year 3 Work Deferred	---	---	$43,000	$43,000	$43,000
Year 4 Work Deferred	---	---	---	$43,000	$43,000
Year 5 Work Deferred	---	---	---	---	$43,000
Engineering Cost	($25,000)	($25,000)	($25,000)	($25,000)	($25,000)
Net Benefit	**$18,000**	**$61,000**	**$104,000**	**$104,000**	**$104,000**

The net benefit is very sensitive to the percent of work that can be deferred each year. The range of typical net benefits would be about $40,000 to $160,000.

Improved Outage Management

Avoided Trouble Calls

PGE estimates that for 10% of trouble calls[9] from customers reporting that their power is out, it is subsequently discovered that no PGE outage occurred. These trouble calls could be avoided using the query function in the AMI meter which can determine whether or not power is being delivered to the meter (i.e., customer premise).

To estimate the range of benefits, we assume the cost of a truck and full time employee (FTE) to be approximately $90/hour. If improved outage management capabilities from AMI save one hour at $90 for 10% of PGE's 2,500 outage calls per year, we would save approximately $22,500 per year. The costs to implement the power status check at the meter include training for the 200 employees who respond to customers and automating the assisted look-up functionality in the affected systems. This could require approximately $10,000 to $20,000 in incremental costs. The primary uncertainty variable in our assumptions is the number of avoided truck dispatches. A range of minus 50 percent or plus 30 percent implies a net benefit range of $10,000 to $30,000 per year.

Faster One-Premise Outage Response

With isolated outages involving only one premise, the time between outage occurrence and notification at PGE is currently expected to be longer than for outages affecting multiple customers. This expectation is based on the likelihood of people being away from their homes during work hours and returning to find that their home is without power. For customers, the effects of the longer outage could have consequences; for example, spoiled food, lower productivity in a too cold or too warm house, etc. With the proposed AMI system, Operators can identify instances of isolated outages and create a service order to initiate repairs without having to rely solely on notification from the customer.

Annually, approximately 3,000 outages occur that affect only one customer. If we assume that 25% occur when the customer is not at home and that the average incremental cost impact to these customers is at least $15 per outage, the resulting societal benefit would be approximately $12,000 per year, plus or minus 50%. PGE, however, does not yet have an estimate for the cost to integrate AMI with the Outage Management System (OMS). Another consideration is that PGE would have to verify the reliability of the AMI outage data because undetected outages and false positive reports would affect the benefit estimate.

Improved Storm Management

This benefit would avoid the costs to address customers who remain without power after a line crew restores power on their tap line, because the AMI system can detect any remaining, isolated customer outages before the crew leaves the area. Restoring the customer service without having to return later saves approximately one hour for a three-man, two-truck crew.

[9] Based on random sample of 2005 Outage Management System (OMS) data.

Assumptions made include the following:

1. One Level 2 outage (affecting 25,000 customers) every year.
2. A Level 3 outage (affecting 100,000 customers) every 5th year.
3. An average of 50 customers restored per crew repair.
4. 10% of repairs leave a customer still out of service.
5. The cost is $315/hour for crew and truck cost[10].

These assumptions imply an average savings of approximately 90[11] crew hours per year, or a cost savings during the storm of approximately $30,000 per year (90 hours x $315/hour). For societal benefits, we assume the customers experiencing the undiscovered outages have five additional hours of outage time. This means approximately 360 customer outage hours could be saved. With an average societal outage cost of $15/hour per customer the societal savings is another $7,000 per year.

The key uncertainties in this analysis are the average number of isolated outages detected by the AMI system in a Level 2 or Level 3 outage, the avoided crew hours from not having to return to the site, and the average extended duration of the outage for the customer. Varying the key variables by minus 50% or plus 50% results in a large range of benefits of $0 to $75,000 per year.

There are unknown costs for information system modifications to: (1) automate meter status checks by distribution element, e.g., by fuse, switch, and (2) improve the quality of electrical connectivity records to ensure accurate analysis. To calculate net benefits, $100,000 in development work is assumed recovered with a 0.20 revenue requirement factor[12].

<u>Faster Fault Location Identification</u>

About half of PGE's SAIDI[13] (System Average Interruption Duration Index) duration is the result of faults that occur when a substation feeder breaker locks open on a downstream fault. Finding the downstream fault, especially on long rural feeders, is a time-consuming process.

A business partner of our AMI vendor is currently developing a fault detection device that would communicate through PGE's proposed AMI system and help pinpoint the location of faults. If PGE places an average of fifteen (15) fault detectors at strategic locations on our longest 450 feeders (covering about 95% of all customers), then the amount of time required to determine the location of a fault should be reduced considerably. The installed cost of a fault detection device is about $250 to $350 per telemetry point (including a system to report the fault data to the

[10] For a general outage, we assume our personnel costs based on 50% straight time and 50% overtime. Distribution line workers cost an average of $90/hour for straight time and $120/hour for overtime (including vehicle, equipment and payroll loadings), for an average of $105 per person per hour. Thus, a three-person crew costs an average of $315/hour when responding to a general outage.

[11] Based on the first 4 assumptions 90 = (25,000 + 100,000/5)/50 * 10%.

[12] A multiplier to calculate estimated typical year revenue requirements. We use a multiplier of 0.2 for software and 0.13 for hardware.

[13] SAIDI is the average annual outage duration for each customer, calculated as the sum of all customer interruption durations during a year divided by number of customers served. PGE's 2005 SAIDI was 86 minutes (1.43 hours).

dispatchers); thus, the installed cost of 15 such devices on each of 450 feeders would be $1.7 to $2.3 million. This implies an annual cost of about $260,000 (0.13* $2.0 million).

PGE has about 250 open breaker events per year and we typically assign a three-person crew to locate the fault. We assume the current outage duration is 60 minutes per incident and the average reduction in outage time would be 20 minutes. We further assume fault detectors will aid detection on 80% of these events. Based on average crew costs of $315/hour, PGE would save about $21,000 per year (-0.333 hours x 200 feeders x $315/hour). In addition, these 200 events affect, on average, about 2,000 customers each; thus, PGE could reduce overall customer outage time by about 130,000 hours per year (200 events x 2000 customers x -0.33 hours per customer). Assuming an average societal loss of $15.00 per customer per hour, this saves about $2 million per year. Including the societal savings, there is a one-year payback. The main uncertainty rests with the actual reduction in the time to locate the fault. With a range of 10 to 30 minutes in outage reduction time, the typical year net benefit is $0.8 to 2.7 million.

<u>Reduced Contact Center Cost</u>

Overtime costs at PGE's Contact Center during major storms runs as high as $3,500/hour. Over a typical three-day event, overtime costs can total as much as $50,000. As customers begin to understand and trust the capability of the AMI system to detect outages and facilitate faster restoration of service, in-bound call volumes might go down -- as might the need for CSRs to call-back customers to verify restoration.

An average annual benefit of $10,000 per year is estimated based on the assumption that improved outage management and reporting will reduce the incidence of customer calls and re-calls by 20%. However, these benefits must be judged against unknown information system costs to facilitate the needs of customers and CSRs. The implementation plan for this initiative is to better quantify the benefit and to identify specific scenarios where benefits could be realized. After generating a list of the information and/or resources that customers and CSRs need to aid their outage-related inquiries/needs, a gross estimate for the information system support cost will be made.

IV. Timetable

The table below shows, for each of the initiatives discussed above, net annual benefits, societal benefits, net present value AMI benefits, and the due date for the initiative's implementation plan. The plans will recommend either a test demonstration to validate key benefit/cost assumptions (of a program-level implementation), or an actual program implementation.

One objective in creating the implementation plans will be to improve our estimates of the costs and benefits based on additional research. Actions to be completed in producing each implementation plan include:

- Complete research regarding cost and benefits including, where appropriate, examining other utility programs.

- Outline the specific process changes required to implement a full program, and also the simplified set for the demonstration, if warranted.
- Identify the key assumptions that need to be validated in a demonstration (if one is proposed) to justify moving forward with a full program implementation.
- Produce a benefit/cost analysis for the demonstration, and also for the full program assuming the key demonstration hypotheses hold true.
- Explain risks associated with implementation if any.
- Provide a timeline for completion of major milestones if the initiative were to move forward.
- Present the economic analysis for the initiative, timeline, and a recommendation to proceed, or not, to OPUC by the due date below.

If terms, mutually agreeable to PGE and OPUC, are reached regarding implementation, then PGE will provide within four months, any additional details required to effect a planned implementation.

Table 1 Estimated Range of Net Benefits

Initiative Category	Net Benefits[14] (thousands)	Societal Benefits[15] (thousands)	NPV AMI (millions)	Plan Due Date
Demand Response Market Pilot	$0-2,300	[16]	$0 - 27	Sept 2007
Appliance Market Transformation	$0-500	[17]	$0 - 5	Aug 2007
Info-Driven Energy Savings	$150 - 800		$2 - 9	July 2007
Avoided transformer failure	$30-170	$10-30	$0.4 – 2	June 2007
Deferred Feeder Conductor Work	$40-160		$0.4 – 1.6	Sept 2007
Improved Outage Management	- - Typical Year Benefits - -			
-Avoided Trouble Calls	$10-30		$0.1 – 0.3	Sept 2007
-Faster One-Premise Response	-	$10-20	$0.1 – 0.2	June 2007
-Improved Storm Management	$0-75	$60-200	$0 – 0.8	Sept 2007
-Expedite Fault Location	($240) [18]	$1,000-3,000	$9 - 30	Sept 2007
-Reduced Contact Center Cost	$10		~ $0.1	June 2007

[14] These estimates are assumption-driven with large uncertainty around the number of customers that will actually participate. Some of the scenarios produce negative net benefits.

[15] Dollar amounts listed are based on an average cost to customer during an outage of $15/hour for lost productivity and/or specific losses, e.g. food spoilage.

[16] The benefit would be reduced if the customer incurs incremental costs to purchase controls, e.g., water heater timer, programmable thermostat, etc. to moderate the personal attention required.

[17] If this demonstration were to influence the adoption of a national appliance standard, PGE believes the long term societal benefit would exceed the entire cost of the AMI system multiple times.

[18] Most costs are recovered from the assumed societal benefit; utility benefit alone does not justify installation.

Attachment 1

Summary NPV

Attachment 2

Analysis of Demand Response Benefits

Update: Smart Grid Metrics

Follow up to 2014 Smart Grid Report

March 12, 2015

Presenters:
Elizabeth Paul, Director of Business Model & Program Development
Rob Weik, Supervisor, Strategic Asset Management
Darren Murtaugh, Manager, Transmission & Distribution Planning

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Purpose of Today's Discussion

Follow up on information requested at PGE's 2014 Smart Grid Report presentation to the OPUC:

- Share PGE's proposed Smart Grid metrics
- Review the results of PGE's Conservation Voltage Reduction pilot

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OPUC's Recommended Metric Topic Areas

- Improved Power Reliability & Safety
- Improved System Visibility
- Fewer & Shorter Outages
- Faster Outage/Fault Identification
- Quicker, More Efficient Customer Service
- Extend Life of Assets And Minimize Asset Downtime or Death
- New Customer Services
- Integration With Demand Response & Distribution Generation Resources

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Recommendation: Consolidate Categories

- Improved Power Reliability & Safety
- Improved System Visibility
- Fewer & Shorter Outages
- Faster Outage/Fault Identification
- Quicker, More Efficient Customer Service
- Extend Life of Assets And Minimize Asset Downtime or Death
- New Customer Services
- Integration With Demand Response (DR) & Distribution Generation Resources (DGR)

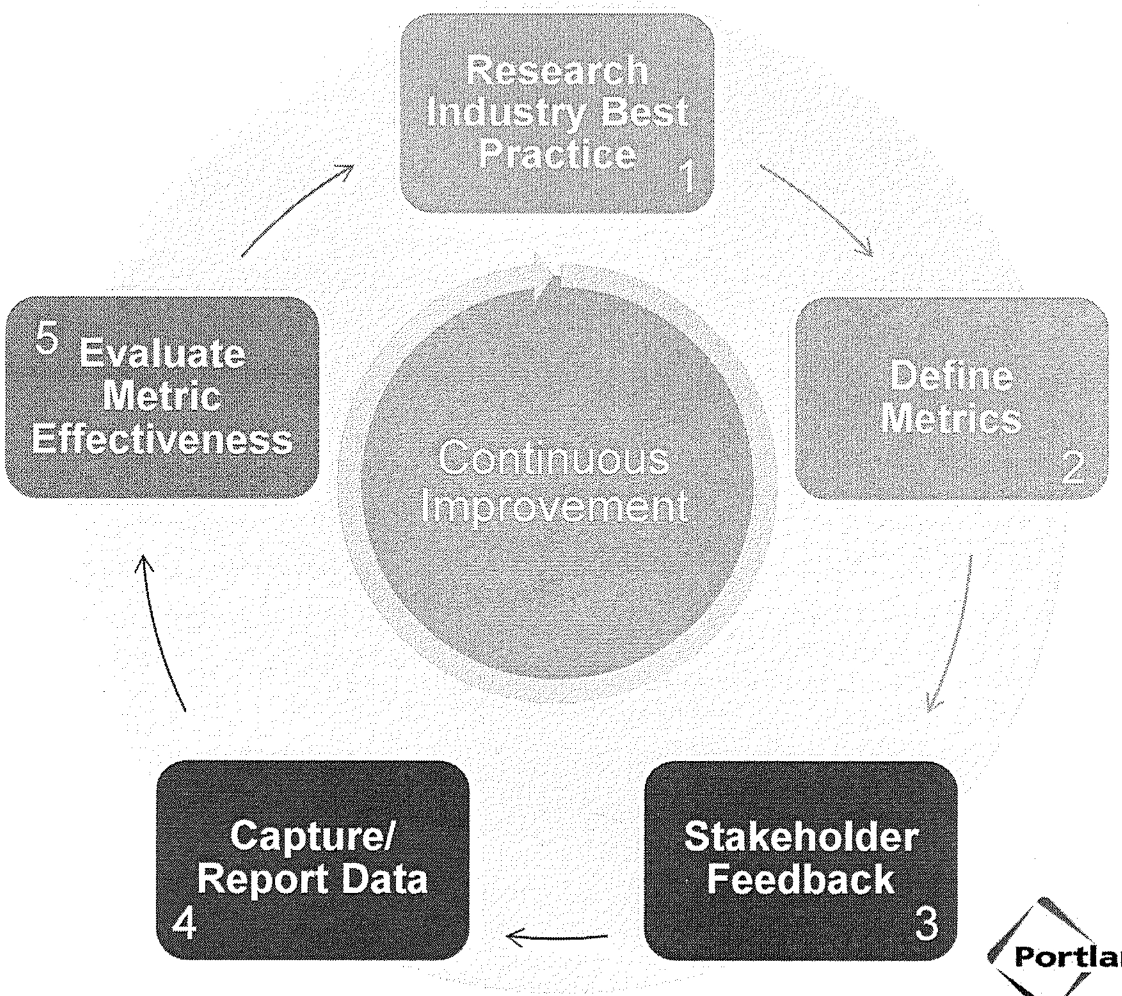
Improved System Visibility

- Reliability
- Asset Optimization
- Customer Engagement

Safety

Iterative Approach Needed

Metrics are not static and may evolve over time



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System Visibility & Safety

Improved System Visibility

- Reliability
- Asset Optimization
- Customer Engagement

Safety

Illustrate how Smart Grid investments:

- Improved system visibility, and
- Safety

Recommended Metrics: Reliability

Illustrate how Smart Grid investments:

- Improved delivery of electricity to customers, and
- Limited or reduced time of interruptions

Reliability Metrics

Existing Metrics	• SAIDI, SAIFI, CAIDI, MAIFI • % of substations equipped with SCADA • % of critical transformers with dissolved gas analyzers • Distribution Feeder or Equipment Overloads
Proposed Metrics	Near-term • Customer/transformers experiencing multiple interruptions (CEMI) • Customers/transformers experiencing long interruption durations (CELID) Long-term • Average Service Availability Index (ASAI)
Rationale	• More granularity (down to end-use customer-level) • Traditional metrics are system-level • Will supplement existing metrics • More agile to help address customer concerns • Increased visibility – more actionable information

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Recommended Metrics: Asset Optimization

Illustrate how Smart Grid investments:

- Optimized value of Company assets and equipment

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Asset Optimization Metrics

Existing Metrics	• Equipment loading • N-1 availability (redundancy)

Proposed Metrics	• Efficiencies realized through conservation voltage reduction
	• Risk holding and mitigation
	  • Risk values derived from economic model
	  • Risk = Likelihood of failure x consequence of failure
	  • Metric utilized to optimize addition, replacement, and maintenance investments decisions for transmission and distribution assets

Rationale	• Visibility and asset failure prediction.
	• Reduced energy demand.
	• Optimize lifecycle, function and replacement of assets.
	  • Assets can become more costly/dangerous to maintain than replace.
	  • Smart Grid upgrades may accelerate replacement of obsolete assets.
	• Accelerated retirement of targeted assets, in a planned and deliberate manner, can enable reactive asset strategies for other assets.

Recommended Metrics

Improved System Visibility

Reliability

Asset Optimization

Customer Engagement

Safety

Illustrate how Smart Grid investments:

- Added customer value, and
- Increased customer engagement in managing their energy usage

Customer Engagement Metrics

Existing Metrics	• Customer participation levels
	  • # customers utilizing energy information services
	  • # customers on TOU rates
	  • # customers participating in demand response & DSG
	  • Available capacity (MW) and location of DR participants
	  • Available capacity (MW) and location of DSG participants
	  • Capacity (MW) and location of customer-owned renewable resources
	• Number of new programs/services being offered

Proposed Metrics	• Adoption by segment of selected programs
Rationale	Increased visibility: 1. Insight into which customer classes have access to various types of Smart Grid programs 2. Insight into which types of customers are participating in available programs Will inform new initiative development & program design

Proposed Output: Annual Smart Grid Report

Performance Appendix for Smart Grid Annual Report:

Appendix A: Smart Grid Performance Metrics

Reliability				
Metric	**2012**	**2013**	**2014**	**3-yr Avg**
SAIDI	A	X	Y	Z
SAIFI	A	X	Y	Z
MAIFI	A	X	Y	Z
CAIDI	A	X	Y	Z
% Substations with SCADA	A	X	Y	Z
% Critical Transformers w/ DGA	A	X	Y	Z
ASAI	*Potential Future metric: Not yet capturing*			
CEMI	*Potential Future metric: Not yet capturing*			
CELID	*Potential Future metric: Not yet capturing*			

Asset Optimization				
Metric	2012	2013	2014	3-yr Avg
# of Transformers > 80% Loaded	A	X	Y	Z
# of Feeders > 80% Loaded or > 12 MVA	A	X	Y	Z
[illegible]	A			

Smart Grid Report Next Steps

Task	Tentative Date
Draft Report to External Stakeholders	04/10/2015
Workshop with External Stakeholders	04/15/2015
Comments from External Stakeholders Due	04/22/2015
Report Filing	06/01/2015

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Questions

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APPENDIX

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Resources

- https://www.smartgrid.gov/sites/default/files/pdfs/methodological_approach_for_estimating_the_benefits_and_costs_of_sgdp.pdf
- http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-23423.pdf
- http://oSmart Gridug.ucaiug.org/Shared%20Documents/KEMA%20Smart%20Grid%20Evaluation%20Metrics%20DRAFT.pdf
- https://www.smartgrid.gov/sites/default/files/pdfs/metrics_guidebook.pdf
- https://www.smartgrid.gov/sites/default/files/pdfs/Smart Griddp_rdsi_metrics_benefits.pdf
- http://www.smartgridinformation.info/pdf/4890_doc_1.pdf
- http://www.sciencedirect.com/science/article/pii/S0301421509003395
- http://www.accenture.com/SiteCollectionDocuments/fr-fr/Accenture-Unlocking-Value-Metrics.pdf

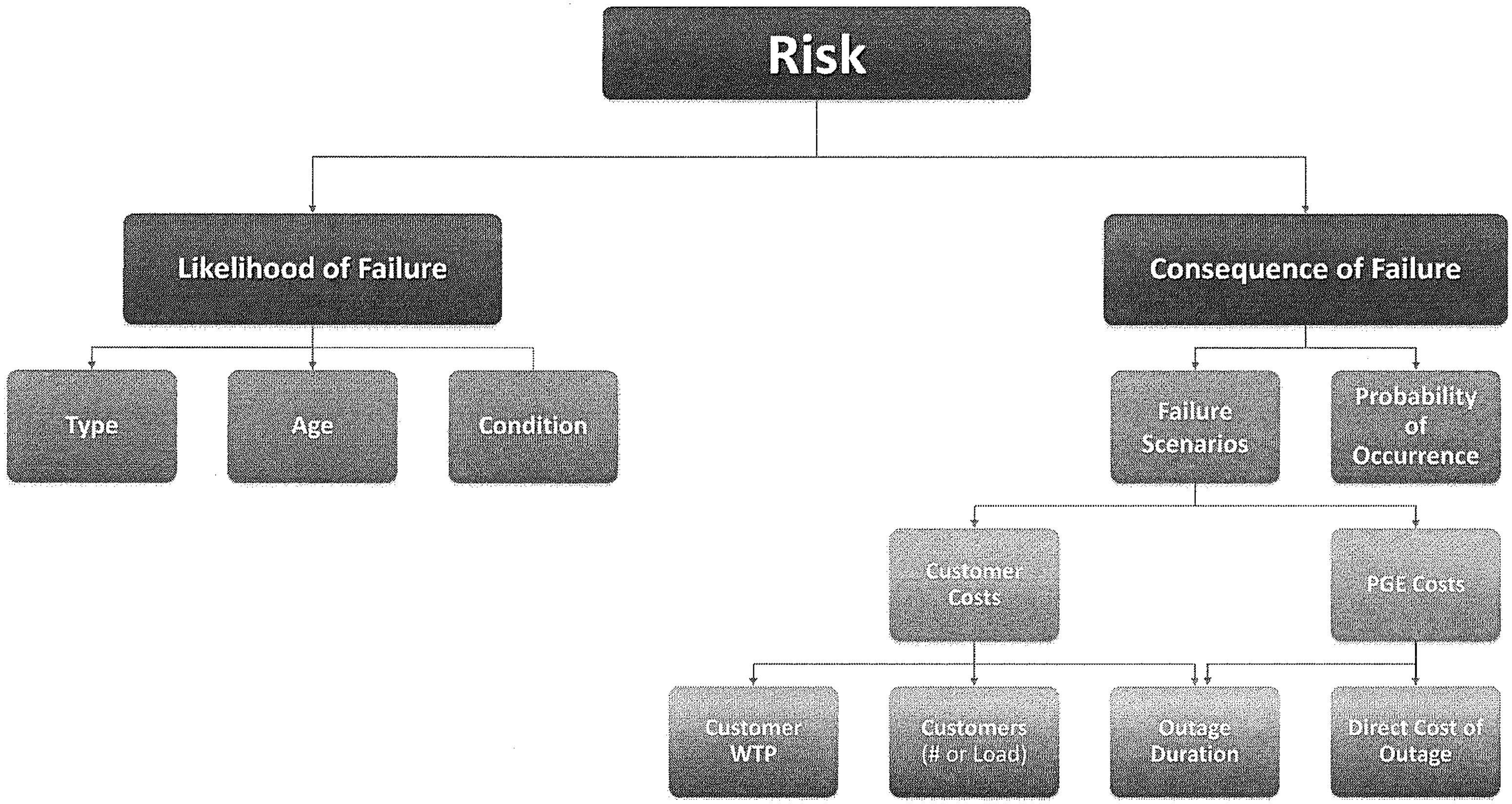
ASAI

$$ASAI = \frac{\sum N_i \times 8760 - \sum U_i N_i}{\sum N_i \times 8760}$$

$$ASAI = 1 - \frac{SAIDI}{8760}$$

i = a particular location
N_i = Total number of customers at location, *i*
U_i = Total outage time at location, *i* (in hours)

Strategic Asset Management (SAM) Risk Assessment Methodology



CEMI

IEEE Std 1782-2014
5.5.3

$$CEMI_n = \frac{\sum N_n}{N_T}$$

n = Number of Sustained Interruptions
N_n = Total Number of Customers that sustained more than *n* interruptions
N_T = Total Number of Customers

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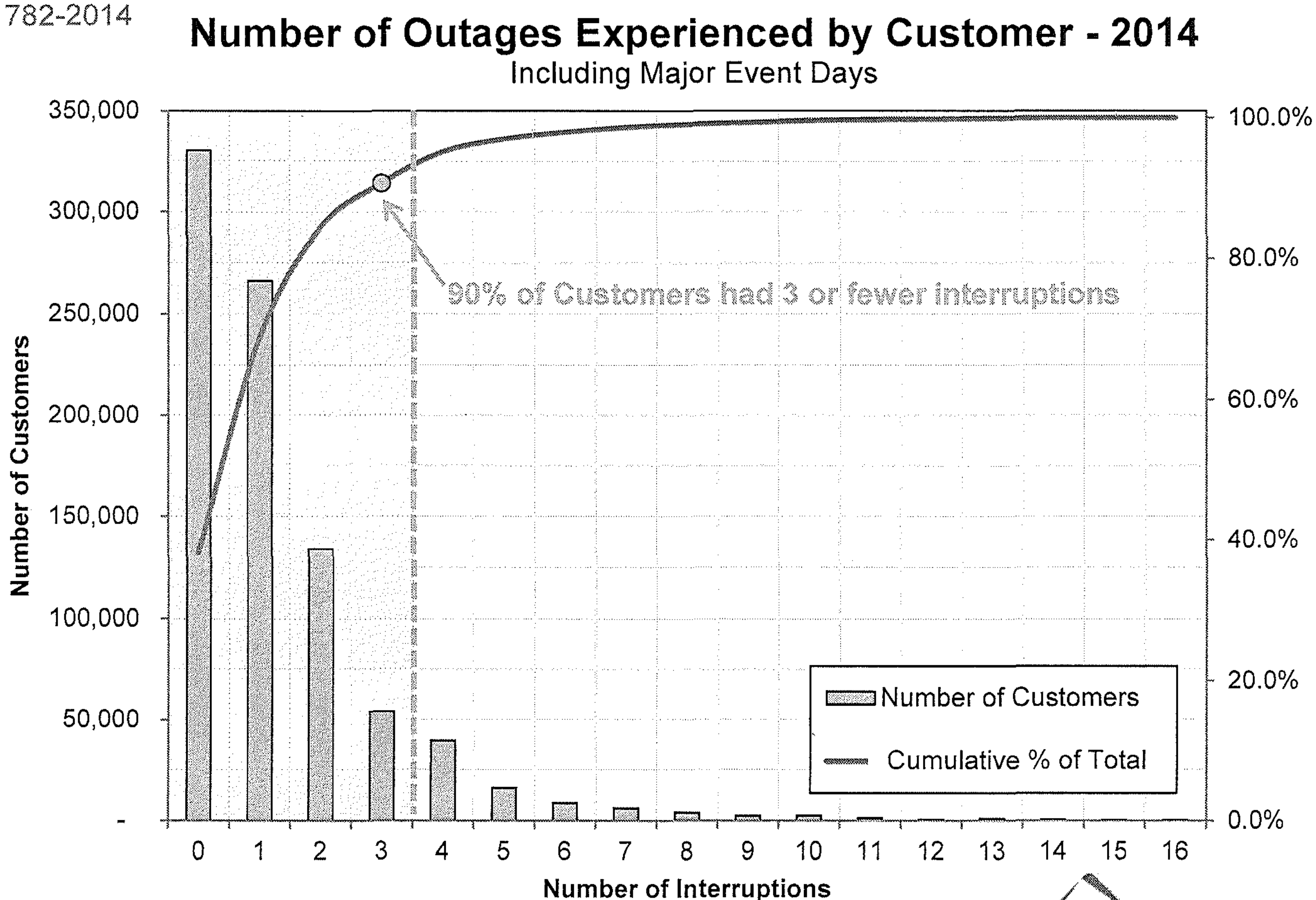
CEMI

IEEE Std 1782-2014
5.5.3



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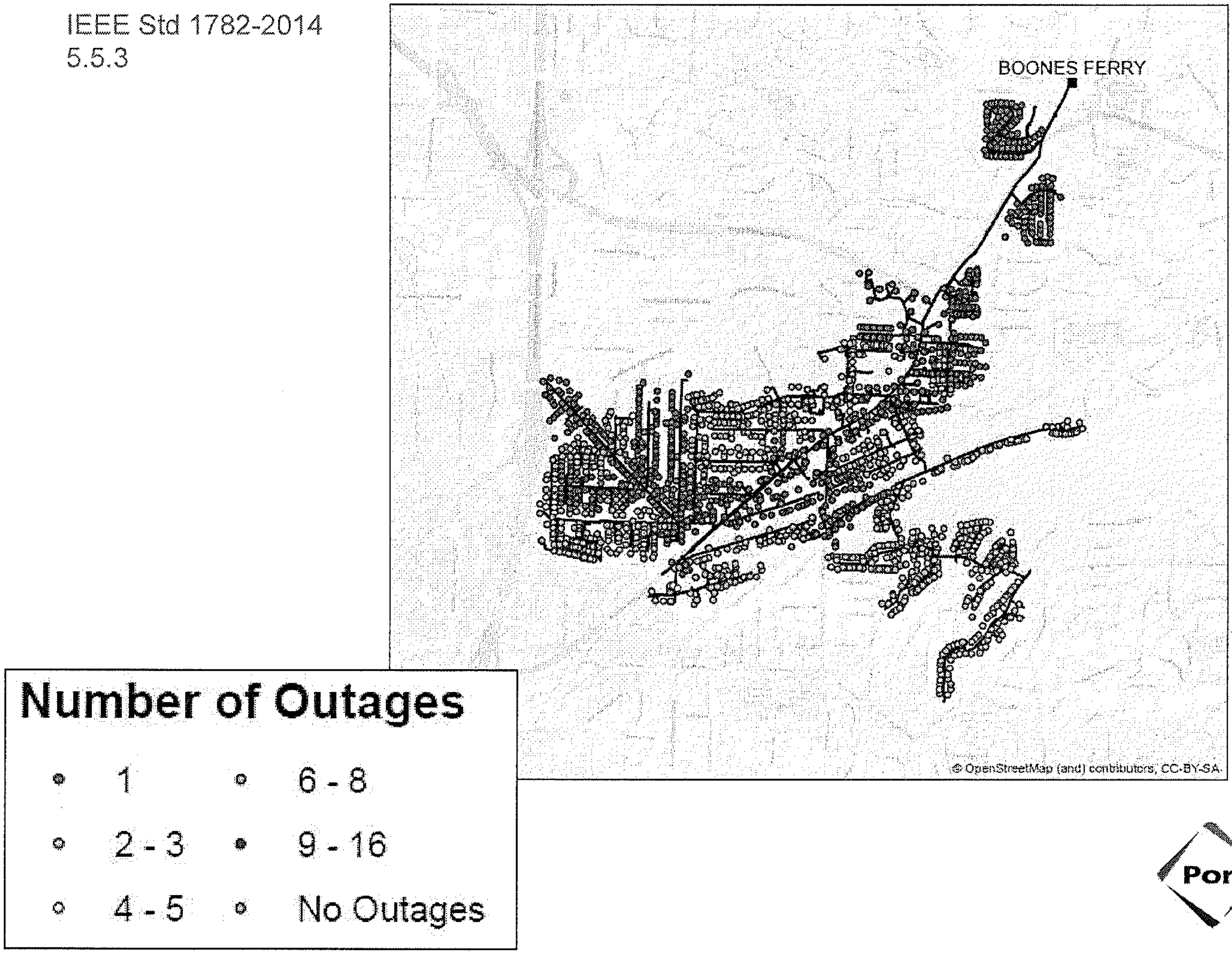
CEMI, Geoanalytics

IEEE Std 1782-2014
5.5.3



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CELID

IEEE Std 1782-2014
5.5.4

$$CELID_t = \frac{\sum N_t}{N_T}$$

t = Total annual duration hours

N_t = Total Number of Customers that sustained more than *t* hours of interruptions

N_T = Total Number of Customers

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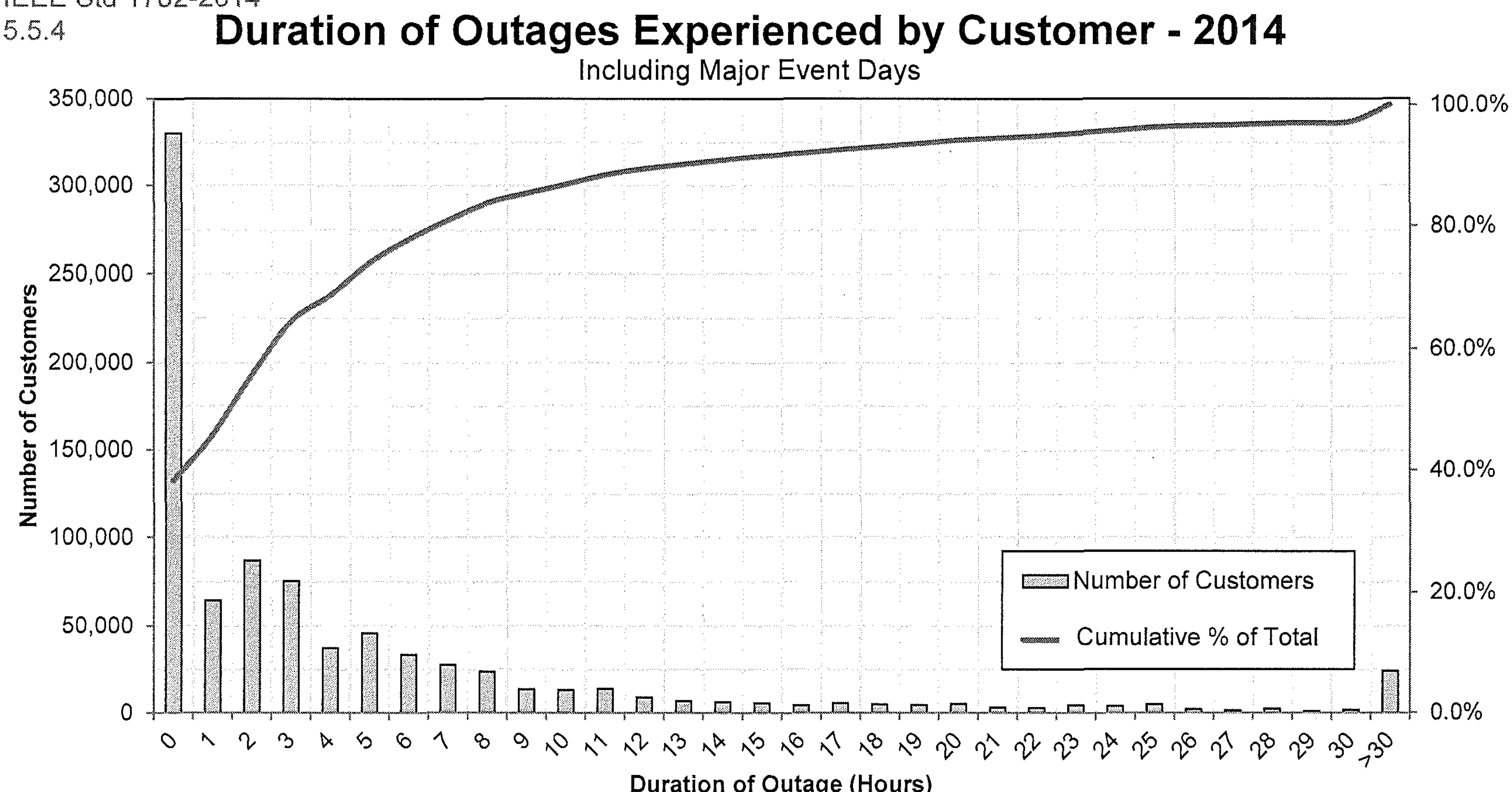
CELID

IEEE Std 1782-2014
5.5.4



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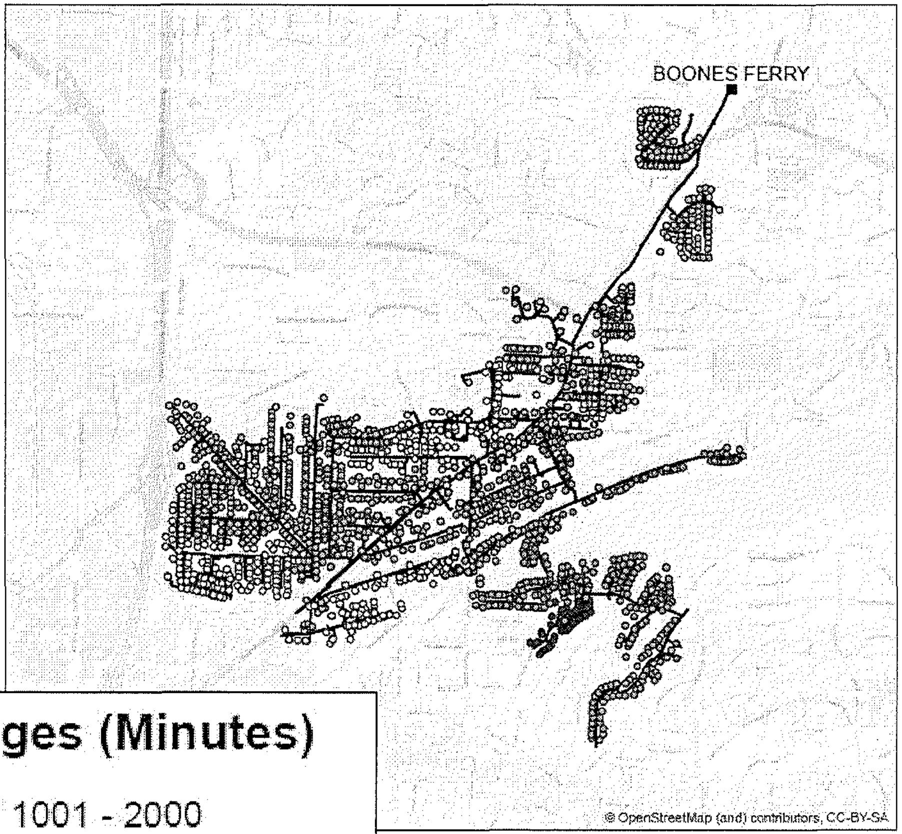
CELID, Geoanalytics

IEEE Std 1782-2014
5.5.4



Duration of Outages (Minutes)

- 6 - 120
- 121 - 360
- 361 - 1000
- 1001 - 2000
- > 2000
- No Outages

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Market Coverage

	Energy Information Services	Energy Efficiency	Demand Response	Pricing	Distributed Generation
Residential					
Commercial					
Industrial					

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Evolution of Smart Grid Projects

R&D → PILOT → IMPLEMENT

QUALITATIVE → **QUANTITATIVE**

10 Step Approach

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

Functions-benefits matrix

Benefits			Functions													
			Trans-mission		Distribution						Substation			Customer		E… Re…
			Flow Control	Wide Area Monitoring & Visualization	Adaptive Protection	Automated Feeder Switching	Automated Islanding and Reconnection	Automated Volt/VAR Control	Enhanced Fault Protection	Real-time Load Transfer	Diagnosis & Notification of Equipment Condition	Dynamic Capability Rating	Fault Current Limiting	Customer Electricity Use & Optimization	Real-time Load Measurement and	Distributed Generation
Economic	Improved Asset Utilization	Optimized Generator Operation		●												
		Deferred Generation Capacity Investments												●		●
		Reduced Ancillary Service Cost		●											●	●
		Reduced Congestion Cost	●	●								●				●
	T&D Capital Savings	Deferred Transmission Capacity Investments	●	●								●	●	●		●
		Deferred Distribution Capacity Investments								●		●		●	●	●
		Reduced Equipment Failures							●		●	●	●			
	T&D O&M Savings	Reduced Distribution Equipment Maintenance Cost									●					
		Reduced Distribution Operations Cost				●		●								
		Reduced Meter Reading Cost													●	
	Theft Reduction	Reduced Electricity Theft													●	
	Energy Efficiency	Reduced Electricity Losses						●		●				●	●	
	Electricity Cost Savings	Reduced Electricity Cost												●		
Reliability	Power Interruptions	Reduced Sustained Outages			●	●	●		●		●				●	●
		Reduced Major Outages		●			●								●	
		Reduced Restoration Cost			●	●			●		●					
	Power Quality	Reduced Momentary Outages							●	●						
		Reduced Sags and Swells							●							
Environmental	Air Emissions	Reduced CO_2 Emissions	●			●		●						●	●	●
		Reduced SOx, NOx and PM-10 Emissions	●			●		●						●	●	●
Security	Energy Security	Reduced Oil Usage (not monetized)				●					●				●	
		Reduced Wide scale Blackouts		●					●			●				

Source: "Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects," EPRI

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To: Wayne, Lei, Ph.D., Customer Strategies Business Development, Portland General Electric

From: Robert Bass, Ph.D., Associate Professor, Portland State University

Subject: R&D Proposal: Non-wires Transmission Solution Study

Date: August 11th, 2016

Several transmission corridors within the Pacific Northwest are currently, or soon will become, congested. Load growth on the western side of both Washington and Oregon, along with increased wind penetration on the eastern halves of those states, have exacerbated the problem. Of particular concern for Portland General Electric is the roughly seventy mile stretch of the I-5 corridor between Longview, Washington and Troutdale, Oregon. Due to the high urban density of the region, securing right-of-way through this corridor to increase transmission capacity may prove to be an insurmountable obstacle unless non-traditional solutions are adopted.

We proposed to conduct a systematic literature review (SLR) assessing the current state of development concerning energy storage as a transmission alternative. SLR is a systematic means for synthesizing research studies and technical reports within a specific discipline. A well-established practice in medicine, psychology and education, SLRs are increasingly being conducted within the fields of engineering and computer science as a means for summarizing the vast quantities of research being conducted in those disciplines. An SLR is formalized through a series of stages:

1. Identify Scope and Research Questions
2. Define Search Inclusion Criteria
3. Find and Catalogue Sources
4. Provide Critique and Analysis
5. Synthesize Findings

We propose to conduct an SLR and write a journal-quality review report of the technologies, policies and economics pertinent to a large-scale Battery energy storage systems (BESS) capable of providing a non-wires solution to transmission congestion. We estimate that a review can be completed by end of Q4, 2016. The review will also include input from regional stakeholders, particularly employees of PGE involved with T&D planning. We will also reach out to representatives at Bonneville Power Administration involved in transmission planning.

BESS located on either side of a transmission corridor could provide temporal regulation of power flow through the corridor. As an example, the I-5 corridor MVA limit is roughly 3000 MW. A transmission-level BESS solution capable of providing two hours of 10% peak shaving would require two BESS facilities, one on either end of the corridor, each having 600 MWh of energy storage capacity and 300 MW of power capacity. To our knowledge, no project of this scale has every been attempted. As such, many questions arise when proposing such a solution. Consideration of the congested I-5 corridor may then be projected to other potential congestion issues within the wider region of the Pacific Northwest.

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The review will consider the following, as pertaining to non-wires energy storage solutions to transmission congestion:

- Technological trends of battery energy storage systems, particularly economics and scalability to transmission-scale applications
- Review of state-of-the-art utility-scale energy storage projects
- Regulatory policy pertaining to energy storage mandates, transmission, energy markets, etc., as relevent to transmission-scale storage
- Impacts of current and projected renewable portfolio standards

The Power Engineering Group at Portland State University has extensive experience working on energy storage projects, often in partnership with Portland General Electric. Our work with energy storage focuses on utility-scale systems, including distributed residential energy storage systems, distribution-level systems, and harmonic impacts of electric vehicle charging. We also have experience designing distributed control architectures and optimization routines for energy storage systems. A summary of our storage-related projects follows:

1. **Distributed Residential Battery Energy Storage**
   PSU-ECE PGE 006 Designed, developed and deployed prototype Residential Battery Energy Storage System (ResBESS). ResBESS allow PGE to perform load shifting during periods when demand and supply become mismatched. Such energy reserves, distributed throughout PGE's balancing area, would allow PGE to integrate higher levels of renewable energy resources into its generation mix without adding additional peaking turbines or purchasing power from the energy imbalance market. We have deployed a proof-of-concept system at a PGE residential customer's home, which is being used to demonstrate the functionality and utility of a ResBESS unit.

2. **Distributed Residential Heat Pump Thermal Energy Storage**
   PSU-ECE PGE 012 Designed and developed a prototype thermal energy storage system that provides demand response using residential space conditioning. The system uses two heat pumps, one utility-owned pump that manages thermal energy from the exterior of the house and store it in a water tank, and one customer-owned pump that serves the heating or cooling needs of the home, to decouple energy consumption from energy production. The system provides space-conditioning while allowing the electric utility to shift energy consumption to times of lower wholesale cost. An optimization algorithm was developed to minimize cost in light of projected weather, electricity pricing and customer usage.

3. **SSPP Solar Integration**
   PSU-ECE PGE 016 Developed a method for determining the power and energy capacities of a BESS to mitigate the adverse impacts of high levels of PV generation within a distribution feeder. Used statistical methods to develop recommendations for appropriately sizing BESS. The method determines the amount of PV generation that could be installed on a distribution feeder with a minimal investment in BESS power and energy capacities.

4. **Impacts of EV Charging on Electric Power Distribution Systems**
   PSU-ECE PGE 005 Performed a study and developed modeling capabilities so show the impacts that electric vehicles, and the non-linear, time-variant loading profiles associated with

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their charging units, may have on power distribution networks. Developed a modeling tool within a VHDL-AMS simulation environment for analysing these effects. Collected data from EV charging stations on the Portland State University campus. Used these data to create harmonic profiles of the EV charging units, which were then used to develop generalized models for Level 2 and Level 3 EV chargers. Validated these models within a larger system context using the IEEE 13-bus distribution test feeder system.

5. **SSPP BESS Control Modeling**
PSU-ECE PGE 007 Developed an s-domain plant model based on frequency and step-response system identification test data from PGE's SSPP. Developed a smoothing algorithm within a programmable logic controller (PLC) as part of a hardware-in-the-loop simulation environment in order to learn about the challenges of implementing such a function within a PLC. The smoothing algorithm and a PI controller reside within the PLC. Together, these elements of the simulation environment model the feeder behavior and the BESS's ability to provide firming and shaping services in light of high penetration levels of PV within the feeder.