BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1657

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2015 Annual Smart Grid Report	STAFF'S COMMENTS

These comments are submitted in response to Portland General Electric's (PGE or Company) third annual Smart Grid Report.

In 2012, the Commission adopted a smart-grid reporting requirement for PacifiCorp, PGE, and Idaho Power Company to "ensure that utilities are systematically evaluating promising smart-grid technologies and applications, that the Commission is kept apprised of utilities' progress, and that stakeholders, Commission Staff, and the Commissioners have an opportunity to provide input into utility evaluations of smart-grid technologies and applications, as well as their plans for smart-grid investments."[1]

At a minimum, the utility's Smart Grid Report must include:

1. Smart-grid strategy, goals, and objectives.
2. Status of smart-grid investments the utility plans to take in the next five years and of projects already underway.
3. Smart grid opportunities and constraints.
4. Targeted evaluations of technologies and applications pursuant to Commission-approved stakeholder recommendations.
5. Related activities such as investment to addressed physical-and cyber-security, privacy, customer outreach and education, etc. [2]

[1] Order No. 12-158 at 1.
[2] Order No. 12-158 at 6 (The actual guidelines include more detail regarding each of these requirements).

The Smart Grid Guidelines specify that each utility's first report must include all smart-grid reporting elements identified in Order No. 12-158. Subsequent reports need only include incremental additions and updates of all elements in the first report and information that may be required by Commission in a previous order.[3]

Order No. 14-333 accepted PGE's 2014 Smart Grid Report, with the inclusion of the following recommendations:

1. In the first quarter of 2015, PGE should report to the Commission on the findings from the Company's Conservation Voltage Reduction (CVR) pilot program and the Company's next steps for expansion of the CVR program.

2. In the first quarter of 2015, PGE should provide the Commission: (1) an evaluation of the Company's Critical Peak Pricing (CPP) program; (2) any recommended changes; and (3) next steps for the program.

3. Before the next report, PGE should conduct workshops, including one with the Commissioners, to explore how best to measure and track benefits of Smart Grid investments such as:

    a. Improved power reliability and safety

    b. Improved system visibility

    c. Fewer and shorter outages

    d. Faster outage/fault identification

    e. Quicker, more efficient customer service

    f. Extend life of assets and minimize asset downtime or death

    g. New customer services

    h. Integration with demand response and distribution generation resources

    As part of the workshops, PGE should explore the development of metrics beyond the System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and others currently in use.

4. Before the next report, PGE should report to the Commission on the Company's evaluation of deployment of more synchrophasors in its system.

5. In the next report, PGE should provide information on PGE's Smart Heating, Ventilating, and Air Conditioning, and Smart Thermostats pilot, including what will be tested and how success will be measured.

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[3] Order No. 12-158 at page 4, UM 1460, May 8, 2012.

6. In the next report, PGE should share lessons learned from the Salem Smart Power Project and how results will be: (a) documented and shared; (b) built upon going forward; and (c) evaluated in terms of cost effectiveness.

7. PGE should document use of smart inverters in its service area and report on future initiatives.

8. In the next report, PGE should report on its evaluation of whether to actively promote voluntary residential and small commercial time of use pricing programs.

In these comments, Staff will analyze how PGE addressed the requirements for subsequent smart grid reports for incremental additions and updates of all elements in the first report and how PGE addressed the requirements set forth in Order No. 14-333. Staff reviewed PGE's 2015 Smart Grid Report that was submitted on May 28, 2015. Staff finds the report very broad in ongoing and planned efforts, which is encouraging and commendable, but lacking in depth in the descriptions and analyses of Company efforts. In some cases, Staff felt that PGE did not provide enough information to satisfy the clear and explicit requests of the Commission-adopted recommendations.

Below Staff comments on each PGE's response to the Commission recommendations adopted in Order No. 14-333 except number seven as well as on non-wire alternatives, customer outreach, continuous communication upgrades, behavioral pricing programs, the transmission and distribution (T&D) visualization, and the Company's Smart Grid Vision.[4]

Order No. 14-333 Requirements

Requirement #1: Report re: Conservation Voltage Reduction (CVR) Pilot Program and next steps.

Staff appreciates PGE's final pilot CVR report submitted in the UM 1657 Smart Grid docket on December 8, 2014. Staff found that it sufficiently and succinctly informed the Commission of the Company's recent and planned CVR efforts. The Company's preliminary results from the CVR pilot are promising and exciting: from implementation at two transformers, the Company calculated that energy savings were 2.3% and 1.4% for the "winter" and "summer" months, respectively, and that the benefit-cost ratio was 3.77.[5] From an initial screening of potential qualifying transformers, PGE estimates that implementation of CVR at 94 transformers currently equipped with necessary communication equipment could yield annual energy savings of approximately 142,934 MWh, or approximately 16 aMW. PGE states that additional screening may identify additional qualifying transformers.

Staff understands that, given the manual intervention required to successfully operate the CVR pilot project, PGE first must upgrade certain communication and analytics hardware and software to enable an automated, and therefore an expanded and more effective, CVR system.[6] However, in the order acknowledging PGE's 2013 Integrated Resource Plan (IRP), the Commission required the Company to

[4] Staff finds PGE satisfied Commission-adopted recommendation number 7 and has no comments on the topic at this time.
[5] The "winter" months were November through April and "summer" May through October;" present value of system benefits were $2,530,945 and present value of costs were $671,872.
[6] PGE 2015 Smart Grid Report, at page 64, UM 1657, May 28, 2015.

include a portfolio level analysis of CVR in its next IRP.[7] Thus, Staff anticipates PGE will include system-wide CVR implementation as an action item in their upcoming IRP, and will keep the Commission abreast of any updates to their CVR implementation timeline.

Requirement #2: Report re: Critical Peak Pricing (CPP) Program, recommended changes, and next steps.

Staff notes that the CPP report provided in the 2015 Smart Grid Report is identical to the one that PGE provided over a year ago in the UM 1427 CPP pilot docket.[8] Staff understands PGE's reasoning for reusing the report: it incidentally satisfies the Commission's recommendation regarding CPP in Order No. 14-333 and required no additional work from the Company. Staff finds PGE's CPP report is sufficient to meet the Commission recommendation in Order No. 14-333. The report reflects that the pilot produced valuable insight into customer participation and opinions as well as data indicating the performance of the program's load shaping during critical peak events in both summer and winter months. DNV GL, the third party hired to evaluate the pilot, produced a comprehensive report that included major findings such as:

- The pilot produced load reductions for both winter and summer: the average drop for a single-family home in the winter ranged between 0.2kW and 0.4kW, and were as high as 0.7kW. Due to a lack of hot days, summer drops could not be quantified, though DNV GL states that load impacts were substantial from visual inspection of load curves.[9]

- Access to pre-program data is crucial to determine customers' responsiveness to a new time-of-use (TOU) program as well as to establish a reliable baseline. Because participating customers' pre-program data was unavailable, DNV GL had to rely on usage patterns from "the average PGE customer" for comparison purposes.[10] This insufficient data comparison prevented DNV GL from determining whether the participants' consumption patterns were in response to the TOU rate, or if they happened to conform i.e., they were already existing.

- The main reason customers chose to participate was to save money.

- Of a total of 996 pilot participants, 444, or approximately 45 percent, dropped out; of those 45 percent, 131 participants, or approximately 43 percent, were dropped because of "eligibility changes," such as customer relocation and alternative bill payment plans.

- Of the customers that chose to drop out (the other 313), 38 percent chose to leave because their respective bills increased after joining the program. 29 percent dropped because they had difficulty reducing or shifting electric usage.

[7] See Order No. 14-415, Appendix A, Page 1 of 2, LC 56.
[8] PGE's Critical Peak Pricing Pilot Report, UM 1427, May 30, 2014.
[9] DNV GL claims that because of PGE's service territory's "very mild weather," and thus very few hot days, during the pilot's 2012 and 2013 operational years, "baselines could not be accurately calculated for these days, and thus there are no load impact estimates for most summer event days." (DNV GL's Critical Peak Pricing Pilot Report, May 15, 2014.)
[10] DNV GL, PGE Critical Peak Pricing Pilot Report, Attachment A, at page 19, May 15, 2014.

After reviewing DNV GL's recommendations for future program evaluation and implementation, Staff finds that though the 2011 CPP pilot successfully introduced customers and the Company to an initial CPP program, it failed to provide a strong foundation of reliable and accurate data and a robust customer experience essential for implementation of either a larger pilot or a full-scale program.

Staff is also troubled by PGE's decision to let efforts into advancing CPP in PGE's territory remain stagnate. Inaction towards any follow-up CPP programming or research after the conclusion of the UM 1427 pilot program seems contrary to both the spirit of Staff's recommendation found in Appendix A of Order No. 14-333, which influenced the Commission's adopted recommendation, as well as Order No. 12-583, specifically the goal to "enhance the ability to save energy and reduce peak demand."[11] Staff recognizes that PGE is pursuing other pricing programs pilots in the form of a critical peak rebate and modified TOU program.[12] However, Staff comments in UM 1708 in which these two pilots are seeking deferral indicate that PGE did not incorporate DNV GL's recommendations regarding crucial elements of successful pilot design. Staff initially did not find evidence of a reliable baseline, a true experimental design, the utilization of high resolution interval data, analysis of how financial savings impacts customer participation, and robust customer education and outreach.

DNV GL's recommendations for future implementation and evaluation provide PGE guidance and opportunities to refine components integral to both a successful and effective CPP program as well as other dynamic pricing programs. Staff would like to see PGE deploy pilots that are designed to be successful and formative so that customers may receive benefits of advancing policy and technology, the latter which ratepayers have financially supported in the form of advanced metering infrastructure (AMI) and the accompanying software. Enough research and development exists nationally now for PGE to draw on in order to provide successful pilots.[13] The Company's efforts in this CPP pilot as well as program development discussed in UM 1708 indicate to Staff that PGE needs to do more in order to enhance the ability of its customers to save energy as contemplated by Order No. 12-158 and to implement CPPs that are consistent with industry best practices.

Requirement #3: Smart Grid Metrics to measure and track benefits of Smart Grid Investments.

PGE's responsiveness to the Commission recommendation and the subsequent efforts in hosting stakeholder meetings as part of the process in developing these initial metrics are commendable. Establishing and subsequently tracking quantitative benchmarks are essential for continued and successful smart grid deployment and provide opportunities for all parties to monitor opportunities for new or corrective action. For example, room for improvement clearly exists in customer utilization of energy information services and customer participation in demand response and pricing programs.[14] Staff will make recommendations in the Staff Report in an effort to improve these metrics.

[11] Order No. 12-158, at page 3, UM 1460, May 8, 2012.
[12] PGE 2015 Smart Grid Report, Appendix 10, UM 1657, May 28, 2015.
[13] US Department of Energy's Interim Report on Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies, Table 14 at 58, June 2015.
[14] PGE 2015 Smart Grid Report, at page 51, UM 1657, May 28, 2015.

For those metrics that PGE states they are “not yet capturing,” Staff would like to see reasons why they were not available in this year’s smart grid report and when the Company expects them to be available. Staff is currently reviewing smart grid metrics used by other utilities in order to determine any best practices for the industry and hopes that PGE is doing the same to ensure currently feasible, complete data transparency.

The initial metrics are a solid start, but opportunities for additional qualitative and quantitative metrics exist. For example, Staff believes customer opinion and performance in pricing programs can be tracked annually to enable programmatic changes when necessary.

Requirement #4: Report re: evaluation and implementation of synchrophasors.

Staff notes that PGE did not submit a report on synchrophasor implementation prior to the filing of this year’s Smart Grid Report as requested in the Commission-adopted Recommendation in Order No. 14-333. PGE’s continued efforts investing in synchrophasors and the accompanying hardware and software support smart grid goals of both the Company and the Commission. Staff would like to know if PGE is participating in the Western Electricity Coordinating Council’s (WECC) Western Interconnection Synchrophasor Project and WECC’s Peak Reliability program. Staff would also like the Company to reconcile differing information found within the 2015 Smart Grid Report: on page 26, the Company states “synchrophasor technology is scheduled for two additional substations in 2015…,” while on page 78, the table under the subsection “Cost Estimate” indicates five substations are receiving technological upgrades.

Requirement #5: Information regarding Smart Thermostat Pilot, including what will be tested and how success will be measured.

The availability of a direct load control (DLC) pilot enables customers to save power and lower bills and allows PGE to provide more efficient, reliable power. Additionally, opportunities for customers to be more engaged with their power consumption engender a more receptive environment to smart grid initiatives. PGE’s Smart Thermostat Pilot is a DLC program that other utilities are currently exploring as an option for reducing peak demand and lowering costs to both the utility and the customer.[15] Though Staff is encouraged by PGE’s DLC thermostat pilot, concerns and reservations exist.

First, Staff found the quantity and quality of information regarding PGE’s Smart Thermostat Pilot in the 2015 Grid Report lacking. Staff finds that the information PGE provided doesn’t satisfy the depth of information the Commission was seeking in its adopted recommendation. Staff had to utilize information found in UM 1708 to fully answer the “what” and “how.” Though the 2015 Smart Grid Report indicated PGE will be testing a customer-provided thermostat program administered by a third party, crucial information such as number of events, event duration, event trigger, customer notification window, customer participation and retention methods, and third-party operability criteria would have greatly enhanced PGE’s response to the “what will be tested” requirement.

[15] US Department of Energy’s Interim Report on Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies, June 2015.

Staff found no indication of how PGE will gauge the success of the pilot in the 2015 Smart Grid Report. Though PGE states that they expect approximately 3.5 MW to 6 MW of demand response (DR), PGE doesn't provide any information to suggest at what threshold the program will be successful, i.e., cost effective. How will customer quantitative metrics such as enrollment, participation and retention factor into the Company's determination of success?

Referring to documentation provided in the 2015 Smart Grid Report and UM 1708, Staff believes that PGE's pilots need to be improved to reflect the industry best practices in order to be successful. Lessons learned from the CPP pilot, including how to design a robust experimental program that explores differing pilot characteristics, proper baseline determination, customer education and program transparency to customers are not readily apparent in PGE's Smart Thermostat pilot.

Requirement #6: Report re: lessons learned from Salem Smart Power Project (SSPP) including how results will be: (a) documented and shared; (b) built upon going forward; and (c) evaluated in terms of cost effectiveness.

The SSPP in many ways represents the type of desirable technological arrangement industry reformers envision for the smart grid of the future: integrated technologies that enable more reliable, safe, secure, efficient power; saves energy and reduces peak demand; integrates distributed resources and enables greater customer participation; and operational efficiency and optimization of utility resources. Many of these smart grid characteristics are facilitated by the core feature of the SSPP, transactive control of SSPP assets, which was crucial to the delivery of the five contractual assets in the partnership with the US Department of Energy. At the completion of the five year project term, PGE confirmed those five assets as used and useful utility assets:

1. Residential DR
2. Commercial DR
3. Commercial dispatchable standby generation (DSG)
4. Battery storage – grid connected
5. Distributed switching and commercial microgrid

Other uses of the SSPP can be found on page 82 of the 2015 Smart Grid Annual report; all but three are well under way or completed. Staff finds the high-level results provided by PGE in the 2015 Smart Grid Report promising, but expected greater detail regarding the performance and technical specificity of the microgrid capabilities and performance, dispatchable energy solutions using Kettle Brand's solar system, and how that can be applied to other DSG; the performance and characteristics of the transactional nodes, and the performance of the SSPP's frequency regulation. PGE should anticipate a more exhaustive list of Staff's expectations for reporting the SSPP's performance of the 12 uses identified on page 82 of the report as well as any other questions Staff may have as analysis continues. Staff also expects the Company's full analysis of cost effectiveness of each of the SSPP's evaluated cases and the SSPP as a whole, as indicated in the Commission-adopted recommendation. As with any analysis, Staff would like to see methodology, assumptions, and materials used in arriving at opinions and conclusions of SSPP features, benefits, and costs.

Requirement #8: Promotion of Residential and Small Commercial TOU Programs.

The Commission-adopted recommendation in Order No. 14-333 pertaining to PGE's existing TOU program was to report the status of the Company's active re-evaluation of expanding the program. PGE currently offers the program to Schedule 7 and 12 residential and commercial customers. The Company's status of the effort in the 2015 Smart Grid Report is identical to the one provided in 2014. Use of the same information indicates to Staff that either the Company has not done enough to promote and advance TOU programs on behalf of customers or recent developments have been omitted from the report. PGE states that the Company has "limited promotion of the program at the direction of the Portfolio Oversight Committee [POC] for reasons of cost-effectiveness." [16] Additionally, PGE and Pacific Power have indicated that a focus on TOU marketing is not an effective use of their marketing time. Now that another year has passed where "interest in the program has grown with the availability of interval data and administrative costs have been reduced with the deployment of AMI,"[17] PGE should have even a stronger case to make to the POC that circumstances are better than ever to begin more actively promoting TOU programming to its customers. Most of PGE's customers are currently not benefiting from one of AMI's most promising features: increased pricing intervals that enable pricing programs, peak demand reduction and bill savings. If PGE's claimed obstacles remain the same, Staff is concerned that the POC is hindering deployment of a beneficial program. Utilities are demonstrating that with proper education and program design, customers can save money and have overall high opinions of both the pricing program and the utility.

Additional Topics

Non-wire Alternatives to Distribution Upgrades

As transmission constraints remain and load continues to grow on certain feeders that are already contending with overload issues, utilities including PGE must evaluate options of varying complexity and cost in order to upgrade infrastructure and ensure a reliable and safe electric grid. Staff acknowledges that PGE is investing in platforms that can integrate geographic information systems, AMI data and T&D information. These platforms subsequently enable the utility to identify opportunities to defer or offset capital investment or maintenance. Preventative capabilities like this can provide more efficient and reliable power as well as save both the Company and its customers money. Staff wants to know if PGE has already identified transmission and distribution systems such as feeders that are approaching operating thresholds that require capital upgrades for continued, reliable operation. If opportunities exist to defer costly capital investments, Staff hopes that PGE is already considering non-wire alternatives such as distributed generation, DR, or energy efficiency.

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[16] Ibid., 31; Oregon Administrative Rules, Division 38 implement the direct access statutes found in Oregon Revised Statutes 757.600. For residential customers, the statute directs the Commission to establish a "portfolio of rate options" within the electricity provider, including a time-of-use rate.
[17] PGE 2015 Smart Grid Report, at page 31, UM 1657, May 28, 2015.

Customer Outreach/Engagement

PGE reports a number of investments in the 2015 Smart Grid Report that successfully accomplish the projects' intended goals; they also produce benefits for customers. Such projects include the installation of a distribution automation (DA) system at Gales Greek, which reduced the number of outages and lowered the reliability metrics substantially when compared to the metrics prior to installation. PGE's new Outage Management System (OMS) is expected to be completed and in operation by the end of the year. Benefits of this new OMS include "faster, more accurate information to help prioritize restoration efforts and optimize field crew deployment."[18] Like the DA system, the benefits to customers are real. Staff would like to know more about PGE's efforts in communicating these advancements in PGE's grid operations. Customers not only benefit from DA implementation and an upgraded OMS, but they also paid for them. Does PGE inform customers of the investments that ultimately provide them better and cheaper service? Can the company inform them in such a way that resonates and engenders better customer opinions of PGE, such as indicating roughly how much money and downtime they can expect to save with such an investment? As customers' role in utility operations increases with advances in demand side resources, greater outreach to customers that demonstrates successful investments would behoove the Company.

Continuous Communication Upgrades

Secure and reliable communication capabilities are fundamental to successful smart grid operations. PGE recognizes the importance of different communication channels in smart grid operations as reflected by the status of their "Continuous Communication Upgrades."[19] To incorporate further "distribution automation, synchrophasors, demand response, etc.," PGE is evaluating the purchase of radio spectrum later this year or next year. Radio spectrum is not cheap; Staff would like to know the specifics of PGE's intended uses for any planned purchase and the result of any cost-benefit analysis to support such purchase. Given the current state of PGE's pricing programs for example, Staff would want to perform analysis to ensure that customers' money is prudently spent.

Staff is curious about alternatives to purchasing radio spectrum as PGE considers the need to expand communication capabilities. Particularly, what roles can the Internet serve? Though Internet communication channels may not be the first choice in T&D infrastructure, such as synchrophasors and DA, can Internet communication be adapted and subsequently suffice for these types of smart grid technologies? Proliferation of Internet in residential and commercial customer locations allows for complimentary communication channels to existing AMI if the latter proves insufficient alone. Staff would also like to know more about DR and mobile access integration, i.e., customers utilizing their mobile handsets or secondary computers for remote access and operation of DR programs.

Behavioral Pricing Programs

In addition to critical peak pricing, critical peak reward (CPR), and TOU programs, utilities can also offer behavioral programs such as the company Opower's behavioral demand response (BDR). Staff

[18] Ibid., 28.
[19] Ibid., 21.

understands that the Energy Trust of Oregon (ETO) ran a pilot of Opower's Personal Energy Report program beginning in 2010 to 60,000 customers in both PGE's and Northwest Natural's service territory. Results were promising: though no significant difference in average electric savings existed between control and treatment groups, 0.35% of customer households who were in the treatment group reported participating in another energy efficiency program.[20] This seemingly diminutive amount equates to a 9.2% lift in the participation rate of energy efficiency programs.[21] Staff believes that BDR can be easily implemented and be cost effective due to PGE's existing infrastructure and responsive customer base. As PGE prepares to offer the new TOU and DLC programs described in UM 1708 to a fraction of the Company's customers, a larger portion, if not the majority, of PGE's customers could be enrolled in a BDR or similar program to ultimately prepare PGE's customers for a more widespread and effective pricing program, such as CPR or TOU. Results from the pilot program ETO ran in conjunction with Opower suggest that such a program would result in increased customer participation in DR or pricing programs.

Appendix 9: Visualization of T&D Smart Grid Initiatives

PGE's current and planned efforts involving the Company's T&D grid currently number over two dozen. Such a substantial implementation of diverse and complex initiatives is critical to a flexible, adaptable smart grid, especially when some of these technologies are interdependent. At the smart grid stakeholder meeting PGE held to solicit stakeholder feedback, Staff inquired if the Company were able to create a visualization of all T&D initiatives in order to better comprehend how each T&D component depended on other components and how they all fit into an overall smart grid scheme when combined with the accompanying descriptions. Staff very much appreciates the visualization that the Company supplied; it has proved helpful in Staff's efforts to understand PGE's plans to transition to a smarter and more reliable T&D grid.

PGE's Smart Grid Vision

Recognizing the greater role smart grid technologies and practices will have across all Company operations, PGE has begun a comprehensive process to "develop a more integrated corporate-level strategy and vision of its future state to maximize the benefits of smart grid investments." The expected products could further guide PGE in enhancing Company operations and the services provided to customers: an updated smart grid vision, a smart grid future state, and a road map. Staff is intrigued by this process and has inquired about some of the process's details, but PGE has indicated that the effort is preliminary and that stakeholders will have an opportunity to preview the vision and road map and opine later in 2015. Particularly, Staff looks forward to learning how PGE will define "benefits" and the balance between customers and shareholders the Company will seek as it determines future-states. PGE is prudent to step back and holistically reevaluate the Company's smart grid direction given the myriad and constantly changing technologies. Staff hopes that the Company's vision and road map will be flexible in design to accommodate concerns and suggestions stakeholders may have.

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[20] Energy Trust of Oregon Personal Energy Report: March 2012 Survey Report, at page 23, July 2012.
[21] Ibid.

This concludes Staff comments.

Dated at Salem, Oregon, this 10th day of July, 2015

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