ITEM NO. 1

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: June 23, 2015

REGULAR __X__ **CONSENT** ____ **EFFECTIVE DATE** __June 23, 2015__

DATE: June 15, 2015

TO: Public Utility Commission

FROM: Jason R. Salmi Klotz

THROUGH: Jason Eisdorfer and Aster Adams

SUBJECT: PORTLAND GENERAL ELECTRIC: (Docket No. UM 1708) Application for Deferral of Expenses Associated with Two Residential Demand Response Pilots.

STAFF RECOMMENDATION:

Approve Portland General Electric Company's application to defer for later ratemaking treatment expenses associated with demand response pricing and direct load control pilots, as modified in Portland General Electric Company's June 10, 2015 Reply to Staff's Immediate Program Modifications.

DISCUSSION:

Introduction

Portland General Electric Company (PGE or the Company) proposes to implement two separate residential customer demand response pilots in 2015. The "Pricing Pilot" is composed of three different rate structure offerings – a peak time rebate rate design and two different Time of Use (TOU) rate designs. The "Direct Load Control Thermostat (DLCT) Pilot" is a direct load control program involving responsive thermostats.

Staff examined the pilots to determine whether expenses associated with these programs satisfied the criteria for deferral under ORS 757.259.

Staff identified some areas of concern in the design of the two pilot programs that Staff believes may hamper the success of the programs. Staff also identified additional measures that may be taken to maximize the benefit of the pilot programs. On June 4, 2015 Staff shared with PGE a version of this memorandum recommending denial unless PGE agreed to program modifications as noted in this memorandum. PGE filed its response to Staff's recommendations on June 10 unconditionally agreeing to most of the recommended changes. However, PGE proposed a new baseline methodology. While Staff found merit in the new proposal, it lacked enough detail to be approved. Therefore, Staff worked with PGE to structure an agreeable baseline methodology prior to program implementation. The pilot programs will be otherwise modified as recommended by Staff in this memorandum and agreed to in PGE's June 10, 2015 letter.

Pertinent statutes, rules and orders

ORS 757.259(2)(e) provides that expenses may be deferred to decrease the frequency of rate cases or match customer costs and benefits. If either or both of these statutory criteria are satisfied, the Commission considers whether it should exercise its discretion under ORS 757.259(2) to grant deferral by considering both the type of event that caused the request for deferral and the magnitude of the event's effect.[1] These considerations (event and magnitude) interact with each other and neither is dispositive.[2]

Background

PGE has identified and researched two residential pilots that it believes will best inform development of future demand response programs.[3] PGE intends that the Pricing Pilot will build on lessons learned from a residential critical peak pricing (CPP) pilot program that was effective from November 2011 through October 2013.[4] PGE expects that the DLCT Pilot will test enabling technology and PGE's ability to achieve automated load control among residential customers.[5] PGE intends to begin operating the pilot programs in the third quarter of 2015 and run the programs for two years.[6] PGE presented testimony of Joseph Keller and Robert Macfarlane in support of the application.

Staff worked with PGE since the initial filing to assure a robust record and full understanding of the proposed pilot programs. In February 2015 Staff met with PGE to discuss what additional information Staff needed to conduct a proper review of the proposed pilot programs. Here Staff was seeking necessary information such as

1 Order No. 05-1070 at 2-3.
2 Order No. 04-108 at 8.
3 PGE Application for Deferred Accounting at 2.
4 PGE Application for Deferred Accounting at 2.
5 PGE Application for Deferred Accounting at 2.
6 PGE Application for Deferred Accounting at 2.

baseline calculation methodology and rationale, incentive payments proposed, event duration and event participation rules, and a delineation of what questions PGE was looking to answer with the proposed pilots. Staff's requests resulted in PGE's filing testimony on May 5, 2015.

The pilot programs

Pricing Pilot

The Pricing Pilot allows investigation of two types of demand response dynamic pricing strategies. Some customers will be enrolled in a TOU rate while others will be enrolled in a Peak Time Rebate (PTR) rate program.

PTR programs offer rebates to customers who use less electricity during critical peak events. Similar to CPP, if such events are planned, advanced notice can be provided. In addition, some events may occur on an emergency basis, with customer notification given shortly before, or at the initiation of the event. PTR customers generally remain on a traditional flat rate or TOU tariff. During a critical event, customer demand must be compared to baseline usage to determine the amount of hourly kilowatt (kW) reduction.

PGE will select the participants in the PTR pilot, but a third-party vendor will administer the program.[7] The third-party vendor will 1) determine the individual customer performance; 2) provide customer notifications; and 3) calculate PTR rewards for customers that curtail during an event.[8] Individual rebates will be measured as the difference in energy over the peak period and the customer's personalized baseline.[9] PGE proposes to calculate each customer's baseline using a "similar methodology" applied in PGE's industrial and commercial pilot program.[10]

PGE expects to call at least one event a season and no more than ten.[11] The events will be up to five hours in duration.[12] The vendor will provide customers with energy information and tips on how they can save during peak times via a number of channels (e.g., email, text, and web).[13]

[7] PGE/100, Keller-Macfarlane/13-16.
[8] PGE/100, Keller-Macfarlane/16.
[9] PGE/100, Keller/17.
[10] PGE/100, Keller/17.
[11] PGE/100, Keller/17.
[12] PGE/100, Keller/18.
[13] PGE/100, Keller-Macfarlane/16.

TOU tariffs are demand response (DR) programs that segment each billing month into smaller hourly windows each with a separate pricing level related to production costs. Participants are provided price signals to reduce load during higher cost hours.

PGE is also selecting the customers that will have TOU rates, but a third-party vendor will operate the TOU program.[14] PGE has not finalized the design of the TOU program, but provides an outline of the proposed TOU periods that are designed to capture weekday peak hours during each season.[15] PGE states that it intends to design different TOU rates to reflect PGE's variable power cost in the different TOU periods and to reward customers for lowering costs.[16]

DLCT Pilot

Direct Load Control (DLC) programs are designed to reduce load during extreme events (e.g. high production costs, system reliability, etc.). Participants receive substantial credits for decreasing (shedding) load when an event is initiated by the utility. Some DLC programs provide the utility with direct control over shedding customer loads (i.e. air conditioning cycling or setback programs). Other programs allow the participants to choose how they will shed load (i.e. interruptible or load curtailment programs). Penalties are usually assessed for nonperformance. Again, during an event, customer demand must be compared to baseline usage to determine the amount of hourly kW reduction. For a program such as the one proposed by PGE the baseline calculation is performed at the individual participant level and at the aggregate program level.

PGE intends to contract with a third-party vendor to implement its Direct Load Control Thermostat or DLCT Pilot.[17] Only customers with programmable controllable thermostats (PCTs) are eligible for this pilot. PGE intends to call no more than ten events per season, using the same criteria for calling an event as used in the Pricing Pilot Program.[18] PGE will pay customers $25 for enrolling in the program plus $25 per season (winter and summer) if the customer participates in at least 50 percent of the events called in the season.[19]

[14] PGE/100, Keller-Macfarlane/21.
[15] PGE/100, Keller-Macfarlane/20.
[16] PGE/100, Keller-Macfarlane/20.
[17] PGE/100, Keller-Macfarlane/24.
[18] PGE/100, Keller-Macfarlane/23-25.
[19] PGE/100, Keller-Macfarlane/25.

Analysis

As noted above, Staff recommends certain modifications to the proposed pilot programs to better ensure the success of the pilots. The primary modifications are to the calculation of the customer-specific baselines for both pilot programs and the calculation of the incentives for the PTR program. Staff also recommends a minimum number of events that will be called in each season for both pilot programs and certain actions that should improve PGE's ability to build upon the information obtained from these pilot programs.

Customer-specific baselines

Demand response programs base incentives on whether a customer curtailed during an event and if so, how much they curtailed. The calculation of the baseline is a critical piece of these programs. If the baseline for a customer is calculated too high, the electric utility will pay incentives in excess of the customer response. If the baseline is too low, less or no load reduction will be recorded which can lead to customer non-participation in future DR events. It may also eliminate incentives to participate, resulting in a customer requesting to be removed from the demand response program. Therefore, it is in the best interest of both the utilities and the customers to have as accurate a baseline estimation as possible.

Two common techniques for calculating baselines are day matching and regression analysis. Day matching consists of taking a short historical time period (which can be anywhere from one week to sixty days in length) and attempting to match what the usage for an event day would have been based on the usage during the historical period chosen. Regression analysis simply involves using statistical regression methods to create a model. Once a baseline is calculated using either day matching or regression analysis, it may be necessary to adjust the baseline to factor in the weather effects on a customer's load on the DR event day. This adjustment consists of determining the difference between the calculated baseline and the actual customer load during the ramp period of the DR event day. The adjustment value is mathematically determined and applied to the calculated baseline during the hours of the deployment period of the DR event.

Baseline Methodology and Type of Customer

The use of one baseline methodology for demand response programs targeted at different customer segments is not advisable as different types of customers use energy differently.[20] Baseline calculations are not only specific to the participating customer but the type of baseline used is otherwise specific to the customer type and program type.[21] That is, one would not want to apply a baseline methodology that is used to estimate load drop from industrial and commercial direct load control demand response programs to a residential pricing program. Such an application would unnecessarily increase the chance for over or under estimation of a customer's response to a demand response event.

Baseline Methodology and PGE's Demand Response Pilots

Staff was unable to identify the exact baseline methodology proposed by PGE for their PTR and DLCT pilots. In testimony PGE states that the PTR and DLCT baseline methodology will be, "similar to the baseline methodology found in PGE's Schedule 77."[22] Schedule 77 is PGE's automated demand response pilot program for commercial and industrial customers allowing direct load control. PGE's statement that it will use a baseline methodology in its two residential pilot programs that is similar to the baseline methodology for its Schedule 77 program concerns Staff for two reasons. First, this statement does not provide enough information to enable Staff to make an informed decision on how the baseline for these pilots will be constructed. Second, Staff believes that PGE should not propose to use a baseline methodology from a commercial/industrial direct load control program in a residential pricing program without thorough justification and review of performance and without showing how such methodology was adapted to fit the two residential pilot programs. Schedule 77 baseline methodology reads as follows:

> The Baseline Load Profile is based upon the average hourly load of the five highest load days in the last ten Typical

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[20] Caughlin, Piette at al, (January 2008). Estimating Demand Response Load Impacts: Evaluation of Baseline Load Models for Non-Residential Buildings in California. Demand Response Research Center. See also Order Instituting Rulemaking Regarding Policies and Protocols for Demand Response Load Impacts Estimates, Cost-Effectiveness Methodologies, Megawatt Goals and Alignment with California Independent System Operator Market Design Protocols," OIR-07-01-041, January 2007.

[21] Bode, J., M.P.P. (July 2012). 2011 Aggregator Programs Accuracy of Baseline Estimates DRMEC Load Impact Workshop; See also Piette, M.A. (January 2008). Estimating Demand Response Load Impacts: Evaluation of Baseline Load Models for Non- Residential Buildings in California. Lawrence Berkley National Laboratory.

[22] PGE/100, Keller-Macfarlane/ .

> Operational Days for the Event period and an adjustment to the amounts above to reflect the day-of operational characteristics leading up to the Event. This adjustment is the difference between the Event day load and the average load of the five highest days used in the load profile above during the two-hour period four hours prior to the Event.

Schedule 77 customers are Large Nonresidential Customers who are able to commit at least 201 kW of load reduction. Traditionally, these are energy savvy customers who are capable of assigning resources both in personnel and processes to meet requested load reductions.

On May 22, 2015, PGE supplemented the record in UM 1708 with a report from KEMA on demand response baseline methodology whereby KEMA evaluated several baselines used by several independent wholesale energy market operators; New York Independent Systems Operator, PJM, Midwest Independent System Operator, ERCOT, and the California Independent System Operator.[23] While staff found the study persuasive with regard to the use of day of weather related adjustments, staff was troubled that PGE is relying on a study that is not directly on point or directly related to baseline methodology development for residential demand response programs. The KEMA study cited by PGE would be more aptly applied to PGE's AutoDR program currently part of Docket UM 1415. PGE's dependence on the KEMA study to justify using a commercial/industrial baseline methodology for a residential demand response program is misplaced. Residential customer loads do not follow the same usage pattern as larger customers.

PGE's proposed baseline methodology runs the risk of erring against the customers' measured load curtailment. By making an adjustment to the curtailment that uses the "two-hour period four hours prior to the Event."[24] PGE's proposed baseline may be comparing non-similar usage patterns. While this aspect of an adjustment may make sense for larger energy users whose load profile may be more consistent the average residential customer usage has peaks and valleys. This means that if PGE were to call a demand response PTR event at noon on a Thursday the adjustment would incorporate usage at between 6 A.M. and 8 A.M. The difference in residential usage patterns may unnecessarily skew the adjustment.

[23] KEMA (2011). PJM Empirical Analysis of Demand Response Baseline Methods.
[24] PGE Schedule 77.

Although Staff has confidence that the average residential customer will manage their electric usage during a demand response event, the capabilities will not be similar to a Large Nonresidential Customer. Additionally, Staff believes that constructing a baseline upon the average hourly load is inappropriate for residential customers whose electricity demand will follow a different pattern than Large Nonresidential Customers. Therefore, staff recommends PGE propose a new baseline methodology for both seasons (Summer and Winter) for both the PTR and DLCT pilots. In this case, Staff would review these baselines and inform PGE whether staff agrees with the proposed methodologies. In its baseline proposal to staff, PGE must support its proposed baseline with pertinent information from PTR and DLC studies, pilots and programs in other jurisdictions. While PGE did in the present filing submit a PTR study from a Baltimore Gas and Electric (BGE) PTR pilot, PGE did not use a similar baseline nor explain why the baseline used in the BGE pilot was not applicable here.

De-rate Factor – Customer Incentive

PGE's testimony includes the following table to show its PTR incentive calculation:[25]

Table 2, PTR Calculation

Variable	Value	Units
Frame F SCCT	$124.46	$/kW-Year
Transmission Losses	1.90%	
Secondary Internal Losses	4.74%	
Total Losses	6.64%	
Program Hours per Year	80	hrs
Gross Price	1.67	$/kWh
De-Rate	50%	
Price After De-Rate	0.83	$/kWh

PGE explains that the $0.83/kWh rate is "based on the cost of an F-Frame, single-cycle turbine (SCCT) peaking plant, de-rated by 50% to account for reliability and availability differences between the resources[.]"[26] PGE does not explain why a de-rate factor of 50 percent reasonably accounts for the differences between the SCCT and DR program.

[25] PGE/100, Keller-Macfarlane/19.
[26] PGE/100, Keller-Macfarlane/19, lines 15-17.

Staff previously noted concern with PGE's use of de-rate factors in PGE's 2013 Integrated Resource Plan (IRP). In a Staff memorandum dated October 20, 2014, Staff noted the following regarding PGE's use of de-rate factors on demand response programs,

> Staff also questions the accuracy of the derate factors used in the economic feasibility screening for the individual DR measures. According to the report the derate factors provided by PGE for use in the cost-effectiveness assessment are "rough estimates and were developed based largely on staff intuition".[27] Staff would like to see more rigorous development of screening derate factors to increase confidence in the results.

Staff's comments refer to a Brattle Group study commissioned by PGE.[28] In the report the main authors Ahmad Faruqui and Ryan Hledik questioned the veracity of the science used to construct de-rate factors. Here the Brattle Group noted that de-rate factors are rough estimates and that a standard for developing de-rate factors has not been developed although the California Public Utilities Commission has initiated proceedings. Further the Brattle Group study notes that de-rate factors are used only in cost effectiveness calculations and are used to reduce the value of avoided costs.[29]

None of the practices, studies, or PTR program examples referenced by PGE in its testimony include any mechanism approximating a de-rate factor to reduce the DR program incentive.[30] For example the BGE's PTR program that PGE states is one of the programs influencing the design of its PTR pilot does not use a de-rate factor. Additionally, BGE's PTR incentive rate is significantly higher than the rate proposed by PGE. In their PTR study BGE studied two PTR rates, a PTR low of $1.16/kWh and PTR high of $1.75/kWh.[31]

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[27] The Brattle Group, "An Assessment of Portland General Electric's Demand Response Potential", November 2012, p. 39.
[28] The Brattle Group, "An Assessment of Portland General Electric's Demand Response Potential", November 2012
[29] The Brattle Group, "An Assessment of Portland General Electric's Demand Response Potential", November 2012
[30] See PGE/100, Keller-Macfarlane/6-9.
[31] UM 1708 PGE Response to OPUC IR 001, Attachment 001-A. Dynamic pricing of electricity in the mid-Atlantic region; econometric results from the Baltimore gas and electric company experiment, Ahmad Faruqui, et al at page 85-86.

Furthermore, de-rate factors have thus far only been applied selectively in jurisdictions with more advanced experience with DR to assess avoided costs, not customer incentives.

Because PGE has not established a reasonable basis for using a de-rate factor to adjust the value of customer incentives or a reasonable basis to use any de-rate factor in any capacity in the pilot programs, Staff recommends that PGE not be allowed to use any de-rate factor in its pilot programs. PGE has agreed to this recommendation and will use an "un-derated avoided cost for the incentive in the pilot."[32]

Program Trigger – Minimum Number of Called Events

PGE plans to call on the PTR and DLCT events based on the following trigger factors:

- PGE load is forecasted to be in the top 1 percent of hourly load. In most cases this is the top 0.4 percent of forecasted load.
- PGE load peaks are generally on hot days in the summer (>90 degrees) or cold days in the winter (<32 degrees).
- Generation heat rates and Mid-Columbia prices are both high.
- Wind generation is expected to be low or transitioning.[33]

Staff is concerned that these criteria may not ensure that the pilot programs are utilized often enough to generate enough useful data to assure a robust evaluation of the programs. Staff is also concerned that PGE would trigger these programs when "Mid-Columbia prices are high." This criterion seems rather broad and grants too much discretion to PGE as to when or if the program will be triggered. Therefore, Staff suggests PGE build into the program a minimum number of demand response events over the course of the two demand response program pilot seasons. As these are pilots and data is an important output of any pilot program, Staff wants to make sure that for their investment ratepayers are receiving value from these pilots. As these pilots are too small to affect operation or substitute for a supply side asset their value is to generate data for future use. Staff recommends that PGE's pilots provide for a minimum number of events during each of the pilots' event seasons. PGE has accepted Staff's recommendation and states it will call at least 6 events per season.[34]

[32] UM 1708 PGE Reply to Staff's Immediate Program Modifications at 2.
[33] PGE/100, Keller-Macfarlane/17-18, 25.
[34] UM 1708 PGE Reply to Staff's Immediate Program Modifications at 2.

Event Duration

Event duration is another important operational aspect of any demand response pilot. It is important that the demand response event duration be long enough to meet the needs of the system but not too long that customers question the value of participation. Many utilities have experimented with event durations. PGE is not unique in this respect.

An underlying aspect of event duration in direct load control pilot is a phenomenon known as "cycling." If a utility needs 100 MW of demand response they may overbuild a program participation number such that 125MW of capacity is available but the full number of participants are utilized intermittently (or cycled) during the event period such that a customer's air conditioner, or hot water heater is on for several 20 minute periods during the several hour event. This way the utility receives the needed 100MW of energy while customers are not called upon for the full duration of an event of several hours. A recent study by Lawrence Berkley National Laboratory shows that direct load control programs that use short term cycling strategies have fewer instances of customers opting out of the program.[35]

PGE proposes to have three-hour event durations for their DLCT pilot.[36] Staff does not currently see a reason to change the proposed event duration. However Staff is concerned about how PGE will measure event participation for both pilots. Some participants may not be able to drop load for DLCT's three-hour event period or the PTR's six-hour event period, others may only be able to drop load for a portion of the event period. This raises the question of what is considered event participation and how PGE will define successful participation. Therefore, Staff recommends that PGE evaluate the feasibility of cycling customers during the three-hour event period as another iteration of the DLCT Pilot. Staff believes that cycling may also open the opportunity to use DLCT programs for other energy services than peak load reduction or wholesale market purchase deferrals. PGE should also keep track of customer fatigue over the event period to help identify the ideal event duration from the customer perspective. For the PTR pilot, Staff recommends PGE submit a clear statement of how PGE will define successful event participation. Staff believes that DR programs are as much a customer comfort concern as they are possible energy resources for the company. PGE has agreed to the recommendations regarding cycling and defining successful participation. PGE states that it will explore cycling strategies and will

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[35] http://certs.lbl.gov/pdf/air-conditioning-load.pdf see also http://certs.lbl.gov/pdf/lbnl-5330e.pdf
[36] PGE/100, Keller-Macfarlane/25.

"determine a successful PTR event as one where the population's event participation is 855 or higher for the length of the events."[37]

Enabling Technology

PGE states that part of the reason the Company is running the DLCT pilot is to evaluate enabling technology.[38] Staff applauds this effort. As the studies from BGE and Connecticut Light and Power Company supplied by PGE show, enabling technology increased load reductions from residential customers.[39] In discussion with PGE, Staff asked whether PGE was going to buttress their PTR pilot program efforts with enabling technology that might better enable participants to shed load. PGE informed Staff that most enabling technology is currently too expensive and that making an additional investment of utility supplied enabling technology to the PTR pilot program would create a non-cost effective program.

Staff agrees that utility-sponsored enabling technology can be expensive and increase the program cost. However, one of the best enabling technologies is information. With the build-out of PGE's Advanced Metering Information (AMI) system and anticipated new Customer Information System (CIS), PGE will have better capabilities to send more granular, time variant information to customers. Additionally, with the convergence of the Internet, many customers are already investing in connected home appliances and devices that could assist the PGE system. Finally, some utilities in the Northwest have found other enabling technology that may be cost-effective alternatives to newer high tech gadgetry. The Olympic Peninsula Project conducted by Pacific Northwest National Laboratory, Bonneville Power Administration and Clallam Public Utility District is an excellent example of providing low cost enabling technology to residential program participants.[40]

Staff recommends that PGE explore enabling technology opportunities that may arise after full implementation of their CIS. To this end it is incumbent upon PGE to create a specification for the functionality of the their new CIS that will enable customer on DLCT or PTR like DR programs with granular interval data that assists PGE customers understanding in near real-time of their load drop performance and program participation. Staff recommends that PGE submit an update, prior to completion of the CIS, about the DR enabling functionality and the specifications PGE will build into their

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[37] UM 1708 PGE Reply to Staff's Immediate Program Modifications at 2.
[38] PGE/100, Keller-Macfarlane/16.
[39] UM 1708 PGE Response to OPUC IR 001 Attachment 001-A and Attachment 001-E.
[40] http://www.pnl.gov/main/publications/external/technical_reports/PNNL-17167.pdf.

new CIS. If either the DLCT pilot, the AutoDR pilot in UM 1514 or the PTR pilot are successful such that a broad implementation is recommended staff would want to know that the CIS PGE is investing in will not only be compatible but may enhance the performance of these programs.

Development of Cost Effectiveness Methodology Best Practices

As evidenced by PGE's use of de-rate; the utility and stakeholders will need to explore the development of a cost effectiveness methodology for demand response programs. Demand response can offer many different energy and capacity products. Although demand response is a demand side asset like energy efficiency, it functions more like a supply side dispatchable resource. Therefore it is important that PGE, the Commission and stakeholders develop a cost effectiveness methodology for demand response that is particular to the capabilities and products of this resource. Staff recommends that PGE lead a stakeholder workgroup to develop a cost effectiveness methodology that is unique to demand response. The pilot projects approved in this docket and others will help supply the necessary data and learnings needed to begin crafting a cost effectiveness methodology for demand response.

CONCLUSION

Staff concludes that with the proposed modifications and additions to PGE's proposed pilot programs, the expenses associated with the pilot programs meet the statutory criteria for deferral. Staff believes that properly structured pilot programs will provide benefits to customers, and the costs of the programs are appropriately deferred to match the benefits.

The reason for the deferral satisfies the Commission's discretionary criteria. Although PGE notes in its testimony, it has identified a need for demand response pilot programs to quantify the demand side management capabilities for resource planning and plan full-scale programs once PGE's Customer Engagement Transformation (CET) initiative is complete.[41] And, the Commission order acknowledging PGE's 2013 IRP states that "PGE should pursue other [i.e., than EnerNOC, automate demand response] DR options in light of looming energy and capacity needs."[42]

Staff recommends that the Commission approve PGE's application to defer the expenses associated with the two demand response pilots, as modified by PGE's June 10, 2015 Reply to Staff's Immediate Program Modifications.

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[41] PGE/100, Keller-Macfarlane/3
[42] Order No. 14-415 at 9.

Immediate Program Modifications:

1. Submit new baseline methodologies for both summer and winter seasons to Staff for approval.
2. Modify the calculation of incentive to eliminate use of the "derate" to reduce the incentive. Alternatively, provide staff sufficient information to establish reasonable basis for use of derate factor in calculating incentive. Also, agree to not otherwise use a derate factor in the pilot program without establishing sufficient basis for its use.
3. Establish a minimum number of events that will be called during each season for both the Pricing and DLCT Pilot Programs.
4. Submit a statement of how PGE will define PTR successful event participation.

End of calendar year requirements:

5. Begin a stakeholder process to develop a cost effectiveness methodology for demand response.
6. Update Commission staff on the functionality of their new CIS system before the system has become fully operational and difficult or impossible to change to support broader adoption of residential demand response pilots.

At time of program evaluation report to Staff the outcome of PGE's efforts to:

7. Explore cycling of customer load in PGE's direct load control pilot.
8. Track customer event fatigue in the current pilots to collect information that will prove useful in determining optimal event duration.
9. Explore enabling technologies that can be or will be interoperable with PGE CIS and AMI systems.

PROPOSED COMMISSION MOTION:

Approve PGE's request to defer expenses associated with the proposed demand response pricing and direct load control pilots, as modified in Portland General Electric Company's June 10, 2015 Reply to Staff's Immediate Program Modifications.