Portland General Electric
121 SW Salmon Street · Portland, Ore. 97204

September 27, 2019

Via Electronic Filing

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street, Ste. 100
P.O. Box 1088
Salem, OR 97308-1088

RE: UM 1657 PGE's Smart Grid Report Response Comments

Portland General Electric Company (PGE) respectfully submits our Smart Grid Report Response comments. PGE appreciates Staff's comments and close reading of our 2019 Report as well as prior Commission Orders in Docket 1657.

If you have any questions or require further information, please call me at (503) 464-7805.

Please direct all formal correspondence, questions, or requests to the following email: pge.opuc.filings@pgn.com.

Sincerely,

Jay Tinker

Jay Tinker
Director, Rates and Regulatory Affairs

2019 Smart Grid Report: Portland General Electric Response Comments

PGE submits the following response comments in Docket UM 1657, Portland General Electric Company (PGE) Smart Grid Report. PGE appreciates Staff's comments and close reading of our 2019 Report as well as prior Commission Orders in Docket 1657.

Response to Order No. 12-158 Requirements

In its response, Staff noted that information was necessary to complete Staff identified Requirement #2. In response Portland General Electric submits the following information.

Commission Staff requested information on our Rush Hour Rewards smart thermostat program. Staff wanted to know how cost effective the demand reductions are or were for this program. PGE here presents the cost and cost effectiveness tables for our thermostat program. This table includes all of our thermostat channels including; bring your own otherwise referred to as Rush Hour Rewards, our direct install program and our anticipated direct ship approach.

Activity	2015-2017 Actuals	2018 Actuals	2019 (Jan-Jun) Actuals	2019 (Jul-Dec) Forecast	2020 Forecast	2021 Forecast
Incremental Contract Labor	$110,000	$102,000	$96,000			
Incremental PGE Labor	$ 9,000	-	-	$60,000	$120,000	$120,000
DERMS Provider	$427,000	$834,000	$861,000	$581,000	$1,094,000	$1,658,000
Evaluation	$130,000	$95,000	$33,000		$40,000	$40,000
Recruitment & Customer Outreach	$12,000	$38,000	$69,000	$25,000	$75,000	$55,000
Third party services	-	-	-	$105,000	$57,000	
Total Administrative Costs	**$687,000**	**$1,069,000**	**$1,059,000**	**$771,000**	**$1,386,000**	**$1,873,000**
Total Direct Install Costs	**-**	**$190,000**	**$739,000**	**$1,050,000**	**$1,774,000**	**$1,211,000**
Total Incentives	**$322,000**	**$345,000**	**$94,000**	**$379,000**	**$818,000**	**$1,318,000**
Grand Total	**$687,000**	**$1,070,000**	**$1,060,000**	**$2,074,000**	**$3,978,000**	**$4,402,000**
MW	**4**	**7.3**		**17.4**	**29.3**	**48**

Following is the cost effectiveness table for the direct load control thermostat program which include the Rush Hour Rewards program.

Total Resource Cost (TRC) Test - NPV $000s

Cost/Benefit Category	Costs	Benefit
1 Administrative costs	9,788	
2 Avoided costs of supplying electricity		17,628
3 Bill Reductions		
4 Capital costs to utility	-	
5 Environmental benefits		74
6 Incentives paid		
7 Revenue loss from reduced sales		
8 Transaction costs to participant	-	
9 Value of service lost	3,982	
	13,770	17,702

Benefit to Cost Ratio	**1.29**

Additionally, PGE offers this summary of the pilot evaluation reports submitted to the Commission earlier in docket UM 1708.

Thermostats - winter 2015/2016 and summer 2016.

Research Design

- Cadmus implemented a randomized control trial (RCT) randomly assigning program participants to the treatment or control group, and then conducted tests to verify that the randomized treatment and control groups had statistically equivalent pretreatment consumption.

- Data Sources: Cadmus used data from Participant enrollment data, Interval consumption data, local weather data including hourly average temperatures from December 2014 through September 2016 for seven National Oceanic and Atmospheric Administration weather stations. The team used zip codes to identify weather stations nearest each participant's home and merged the weather data with the participant's billing data.

Program Impacts. The RHR pilot achieved significant demand reductions per customer during RHR events. Load reductions averaged between 0.4 and 0.6 kW per customer in winter and about 0.8 kW per customer in summer.

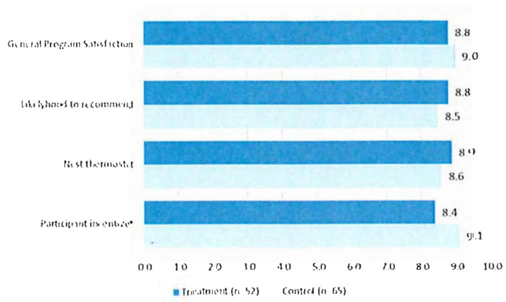
- load impacts decreased during the second and third event hours. Estimated load impacts were 33% to 50% lower in the second event hour and 33% to 80% lower in the third event hour.[1]

[1] This degradation likely reflected drift in home interior temperatures during events due to passive heat loss that caused space conditioning units to resume operation. For example, in summer during event hours, interior temperatures rise until reaching the RHR-adjusted thermostat setpoint. At that point, air conditioning units turn on again and run periodically to maintain the home interior at the adjusted temperature. In poorly insulated homes, interior home temperatures drift more quickly to the RHR-adjusted setpoint, and average load impact are lower. In more thermally resistant homes, interior temperatures drift more slowly, with greater average load impacts.

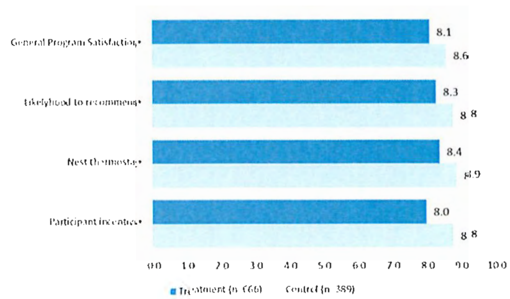
Customer Experience. Winter and summer participants reported high satisfaction levels with a variety of RHR outcomes, including comfort during events, Nest thermostats, participation incentives, and with the program overall. Customers reported higher satisfaction levels after participation.

Winter and Summer Post-Season Program Satisfaction and Likelihood to Recommend

Winter



Summer



Thermostats - winter 2016/2017 and summer 2017.

Program Impacts.

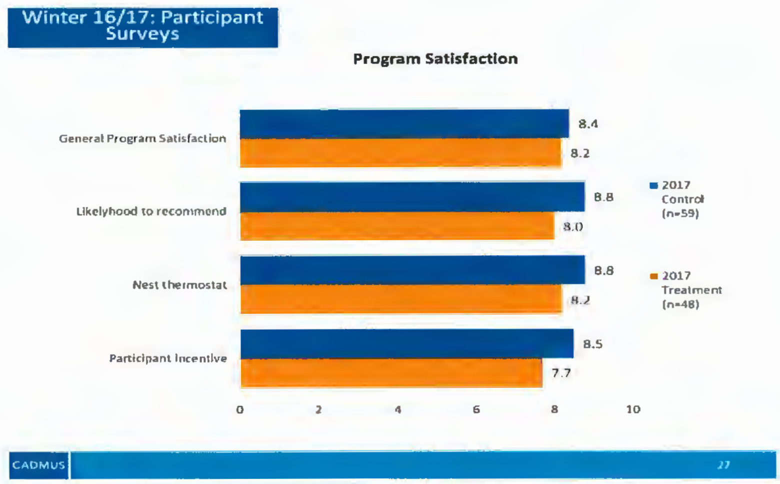
- ~0.9 kW per home in winter 2016/2017
- ~1 kW per home in summer 2017
- Increased impact compared to previous seasons
- Largest load reduction occurs in winter mornings
- >1.5 kW in first hour...most significant value

Noteworthy observation: Pre/post snapback noticeable– important to account in utility operations "snapback" effects, defined as the increase in energy or demand in the hours immediately following a DR event. Snapback results when controlled equipment is allowed to return to its operating set point following the event, and may offset all or part of the energy savings that were achieved when the equipment was cycled off or partially curtailed.

Snapback average: *In winter*, ~ 1 kW per home *In summer*, ~0.5 kW per home

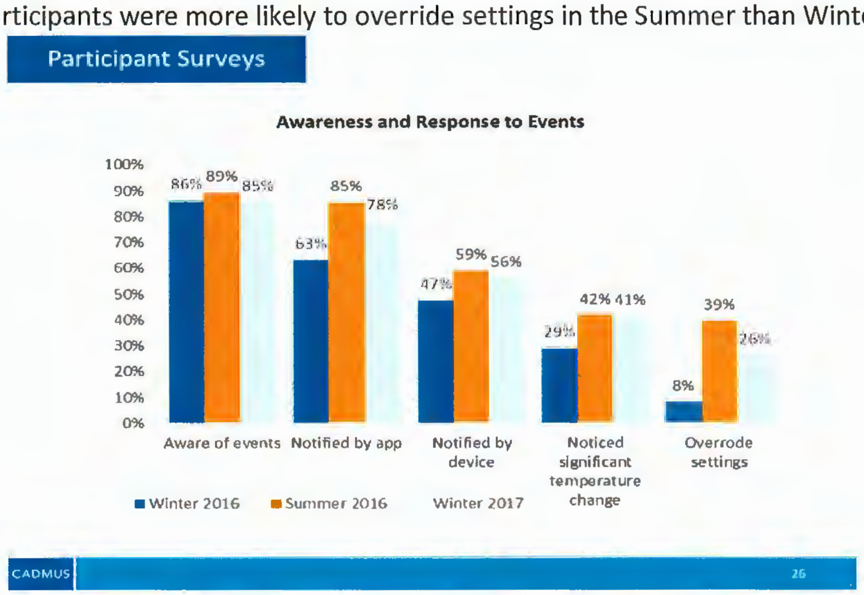
Program Satisfaction

- Still high-8 out of 10 rating



DR Event awareness

Participants were more likely to override settings in the Summer than Winter.



Thermostats - winter 2017/2018 and summer 2018.

Program Impacts.

The program achieved average demand savings of 0.93 kW and 0.62 kW per participant for summer and winter, respectively. These savings represented 32% of summer event hour demand and 23% of winter event hour demand. Evaluated savings surpassed the PGE planning value for BYOT smart thermostat demand response of 0.8 kW per participant, though winter savings were less than the 1.0 kW planning estimate.

Noteworthy observation: load control events increased Snap Back (customer loads before and after events) but overall did not result in a negative conservation effect.

In summer, loads increased by about 14% before events because of pre-cooling and by about 13% after events because of snapback. In winter, loads increased by 20-30% before events and about 20%-30%

after events. However, the pre-conditioning and snapback did not lead to an increase in energy consumption on event days.

Still delivering a positive customer experience and achieved high customer satisfaction.

- Most test group respondents were satisfied with the program (91%). In the open-end comments, test group respondents most often mentioned that the program is helpful to the customer (25%), works well (23%), and saves money (21%). As suggestions for program improvement, they mentioned increasing the incentive amount (30%), sending earlier pre-event notifications (14%), and providing a different incentive structure (13%).

The load control events did not adversely affect comfort for the majority of customers.

- Sixty-two percent of test group respondents said they noticed the summer events. Most noticed the events because of the event message display on the Nest thermostat (72%) and the event notification from the smartphone app (65%) rather than because of a change in temperature (36%). Moreover, before the events, 95% of respondents said their home's interior temperature was comfortable. During the events, 82% said they were comfortable, a significant decrease compared to the comfort level before the events; nevertheless, a majority reported feeling comfortable during the events.

PGE Tested IDR- Intelligent Demand Response (to reduce snapback)
IDR customizes the thermostat setback for individual customers based on historical heating or cooling demand and the thermal properties of the home to achieve more consistent and lasting load reductions across event hours. IDR also includes regulating the dispatch of load control signals to avoid big changes in aggregate loads due to simultaneous pre-conditioning before the event, the event initiation, or snapback after an event.

- Cadmus suggests that PGE do more IDR testing
- Doing more IDR testing only in summer per Whisker Labs (Ecobee & Honeywell)
- Nest no longer doing IDR

Noteworthy observation: In 2017 Honeywell and Ecobee thermostats (Connected Savings) were added to the Thermostat mix.

- It was noticed in summer, PGE can expect the same demand savings per customer from Connected Savings and Rush Hour Rewards participants.
- There were no statistically significant differences in savings between thermostat brands (Ecobee, Honeywell, and Nest). In summer 2018, the average savings of 0.93 kW for Rush Hour Rewards customers was slightly higher than but statistically indistinguishable from the average savings for Connected Savings participants (0.84 kW).

Noteworthy observation: For Connected Savings (Honeywell/Ecobee) PGE's own marketing efforts engaged customers more than marketing efforts from the smart thermostat manufacturers.

- PGE employed the smart thermostat manufacturers' emails, the PGE website, and PGE emails to recruit customers. Of the three marketing efforts, customers took notice of PGE's marketing more than the manufacturers' marketing. When asked how they heard about the program, recruitment survey respondents most often said an email from PGE (48%), an email from a manufacturer (21%), and the PGE website (19%). PGE worked with the manufacturers to increase emails about the program from once a year to quarterly.

Program Challenges

- The lack of existing data on customers' smart thermostats and HVAC systems resulted in program marketing and recruitment challenges.
- The average delay between when a customer installs a smart thermostat and when the customer enrolls in the program suggests an opportunity to accelerate enrollment.
- Customer education is needed about the connection of demand response to smart thermostats.

Implementation Recommendations

PGE should increase marketing efforts specifically at the point of sale or point of installation. This could include the following:

- Partnering with local retailers that carry smart thermostats to display program promotions
- Partnering with local thermostat installation contractors to promote the program during the installation process
- Intercepting customers about the program offering in an online marketplace
- PGE should develop educational content that emphasizes the smart thermostat's connection to demand response. Rather than using words to explain, consider presenting engaging visuals such as an infographic flowchart or a short video that clearly illustrates the relationship.

In response to Commission Staff identified Requirement #3 of Order No. 12-158 Smart Grid Opportunities and Constraints PGE offers the following discussion.

In the 2017 Report, the Company stated the winter 2016-17 reduction dropped to 8.3 MW from the previous year's 13.1 MW and this was caused by "loss of customers to direct access and some reduced nominations from a small set of poor performing participants." In the 2019 Report, however, the Company reveals program participation only dropped down to 45 participants, a sample size not substantially smaller than 2016's 57 and that would not be expected, in terms of probability, to present a substantially different central tendency.

> Although the megawatt per participant chart is a reasonable way to look at Energy Partner enrollment trends over time and provides a way to identify inflection points within the program,

it doesn't consider the actual distribution of customer loads within the program which can lead to inaccurate conclusions about load impacts from customer unenrollment's. In summer 2016 customer nominations ranged from 50 KW to 1.1 MW and the six customers with the highest nominated load reductions accounted for 48% of the total. Enrollment and nomination changes from these larger customers have a greater impact on the total nominated load than an average per participant number suggests. For example, one of the customers that we lost due to direct access was a national retailer with ten stores in our service territory. When that one customer transitioned to direct access at the end of 2016, we lost all ten stores, 1.1 MW of nominated load or about 12% of total load at that time. Adjustments and unenrollment's to a single nomination from a large customer will cause much greater impacts to the total nominated load than an average load per customer would suggest.

The 2019 Report also shows the 2017 winter reduction was 3 MW, not 8.3 MW, much lower than previously reported.

Staff must note the timing of the two reports. The 2017 report was submitted on May 31st, 2017 and at that time 8.3 MW was the known load number for the winter 2016-2017 season (Dec 2016 – Feb 2017). The 2019 report was submitted in June 2019 and included updates for the entire 2017 year which ended with the 3 MW load nomination (Dec 2017).

Staff would like to see a detailed explanation for this drop in winter 2017.

As reported in the 2017 report, "The current program implementer, EnerNOC, has opted to no longer run the program and will leave at the end of the summer 2017 season". Updated information on the subject was included in the 2019 report; "EnerNOC, Inc. and PGE ended the aggregator contract in September 2017" and "PGE contracted with CLEAResult Consulting Inc. to coordinate the customer enrollment and enablement process and with Enbala Power Networks, Inc. to provide the demand response management system (DRMS)". It was a mutually agreed transition because EnerNoc acted as an aggregator focused only on load and could not deliver the required realization rates. Under the new format, PGE modified the tariff (Schedule 26) to provide more options to customers and assure delivery of both load and realization figures.

The load reduction seen in winter 2017 was caused by the transitioning of the program to new implementors. On September 30, 2017, the end of the summer season, every participant was automatically unenrolled from Energy Partner and then PGE, along with the new implementor (CLEAResult), reached out to each customer to re-enroll them in the program. At the end of 2017 we had re-enrolled 3 MW. By the summer season 2018 PGE had enrolled 12.5 MW back into the program. At no time under the EnerNoc contract did this program see such rapid growth.

Tracking this pilot in MW per participant helps control for the reduced participation, but Staff would like to know why there was "poor event realization" in that year and what specific lessons were learned to avoid it in the future.

As noted above, although tracking the pilot using a MW per participant metric is a reasonable way to identify early trends and inflection points (the transition) in the program it doesn't effectively capture details that have impacts to enrollments and total load. Moving forward this metric will become even less effective because of the way enrollments are targeted. The initial focus of the program is to target and enroll customers with the largest loads to get the biggest impact, once we've exhausted large customer opportunities, we'll begin targeting customers with smaller loads. As enrollments for smaller customers increase the MW per participant metric will decrease and may lead to an assumption that there is a problem with the program when it's just a reflection of the way nominated loads are distributed among customers.

The realization issue is related to the way we contracted with the aggregator. In the EnerNoc agreement we only had requirements for total load delivered which we think unintendedly drove more optimistic nominations which were difficult to attain. In the agreement with CLEAResult there are both load and realization requirements which help mitigate the issue of inflated nominations.

Response to Order No. 17-446 Requirements

In response to Commission Staff identified Requirement #1 of Order No. 17-446 report on the effectiveness of the proposed changes to the Energy Partner, Smart Thermostats, and other demand response pilot projects. PGE offers the following discussion.

The effectiveness of a pilot's activity is assessed by a third party per traditional Commission practice. For each of our pilot projects whether Energy Partner, Smart Thermostats or other demand response pilot projects the Commission requires PGE to submit a third-party evaluation. These evaluations are the primary report on pilot effectiveness. This practice is well established through a long history of demand side management (DSM) activities first established through state and regional investments in energy efficiency dating back to 1980. This is done in-part so the Commission and ratepayers are given an unbiased assessment of pilot, project, measure and program effectiveness. The Commission and Staff is well within its' right to request these third-party evaluations as they are valuable to the Commission, stakeholders and customers and the utility. We have submitted several pilot evaluations to the Commission. In July 2018 we submitted a Cadmus evaluation of Flex 1.0. Flex 1.0 was the predecessor pilot to Flex 2.0. Flex 1.0 informed the design of Flex 2.0 and the peak-time rebate therein. Flex 2.0 was only recently approved by the Commission this last April. Our multifamily water heater smart water heater pilot project is only just reaching evaluable participation rates. However, a preliminary evaluation was submitted in March of 2019 with a final to be filed in December of this year. Similarly, our smart thermostat pilot is currently undergoing an evaluation that will be submitted to the Commission later this year. Our thermostat activity, (whether pilot or program) will be reevaluated in 2021 with another evaluation tentatively scheduled for December for 2021. Energy Partner has undergone evaluation by Navigant Consulting, this report will be submitted to the Commission in the coming months. The Testbed evaluator has been chosen through a RFP process of which the Demand Response Review Committee had visibility and influence in. The evaluation of the Testbed project is currently expected in 2022.

For reasons of neutrality and out of respect of the independent process offered by having third party evaluations of pilot activity effectiveness we point the Commission Staff to this evaluation work. PGE could provide further color but feel it is best to allow the Commission to review the evaluation material themselves without our characterization and analysis of activity effectiveness. We offer this simply to respect and assure that the Commission oversight role remains in place as the Commission intended.

In response to Commission Staff identified Requirement #2 of Order No. 17-446 cost-effectiveness methodologies of DERs PGE offers the following discussion.

PGE has not changed its practice of demand response cost effectiveness analysis. PGE is still using the cost effectiveness analysis submitted to the Commission in 2016 in UM 1708. This methodology is one borrowed from California at the direction of Commission Staff. We have not developed a distributed resource cost effectiveness methodology. We have been evaluating possible values for energy storage services pursuant to the requirements of the Commission Energy Storage dockets UM 1751 and UM 1856. Here Commission Order 17-118 identified several energy service valuations to be explored through the pilot proposals to be received in docket UM 1856. The table PGE refers to can be found on page 15 of 40 of the Order's Appendix A.

Category	Service	Value
Bulk Energy	Capacity or Resource Adequacy	The ESS is dispatched during peak demand events to supply energy and shave peak energy demand. The ESS reduces the need for new peaking power plants.
	Energy arbitrage	Trading in the wholesale energy markets by buying energy during low-price periods and selling it during high-price periods.
Ancillary Service	Regulation	An ESS operator responds to an area control error in order to provide a connective response to all or a segment portion of a control area.
	Load Following	Regulation of the power output of an ESS within a prescribed area in response to changes in system frequency, tie line loading, or the relation of these to each other, so as to maintain the scheduled system frequency and/or established interchange with other areas within predetermined limits.
	Spin/Non-spin Reserve	Spinning reserve represents capacity that is online and capable of synchronizing to the grid within 10 minutes. Non-spin reserve is off-line generation capable of being brought onto the grid and synchronized to it within 30 minutes.
	Voltage Support	Voltage support consists of providing reactive power onto the grid in order to maintain a desired voltage level.
	Black Start Services	Black start service is the ability of a generating unit to start without an outside electrical supply, Black start service is

		necessary to help ensure the reliable restoration of the grid following a blackout,
Transmission Services	Transmission congestion Relief	Use of an ESS to reduce loading on a specific portion of the transmission system, thus delaying the need to upgrade the transmission system to accommodate load growth or regulate voltage or avoiding the purchase of additional transmission rights from third-party transmission providers.
	Transmission Upgrade Deferral	
Distribution Services	Distribution Upgrade Deferral	Use of an ESS to reduce loading on a specific portion of the distribution system, thus delaying the need to upgrade the distribution system to accommodate load growth or regulate voltage.
	Volt-VAR Control	In electric power transmission and distribution, volt-ampere reactive (VAR) is a unit used to measure reactive power in an AC electric power system. VAR control manages the reactive power, usually attempting to get a power factor near unity (I).
	Outage Mitigation	outage mitigation refers to the use of an ESS to reduce or eliminate the costs associated with power outages to utilities.
	Distribution Congestion Relief	Use of an ESS to store energy when the distribution system is uncongested and provide relief during hours of high congestion.
Customer Energy Management Services	Power Reliability	Power reliability refers to the use of an ESS to reduce or eliminate power outages to utility customers.
	Time-of-Use Charge Reduction	Reducing customer charges for electric energy when the price is specific to the time (season, day of week, time-of-day) when the energy is purchased.
	Demand Charge Reduction	Use of an ESS to reduce the maximum power draw by electric load in order to avoid peak demand charges.
Source; Modified from Akhil et at.2015.		

PGE anticipates that values will be identified for some of the services identified in Order 17-118. Others such as locational value may be preliminarily identified through the energy storage pilots and some of the activity undertaken in the PGE Smart Grid Testbed. Within the PGE Smart Grid Testbed PGE has hired Kevala, a contractor working with the Energy Trust of Oregon, to identify location value through their Load Management Pilots with PacifiCorp and Northwest Natural. Kevala is being deployed within the Testbed to map and identify preliminarily some of the location values of deployed distributed energy resources modeled and actual. Given that these are all individual docketed activities meant to inform our understanding of DER value we will report on our progress on location valuation of DERs through UM 2005, the Commission's Distribution System Planning docket, and through our Smart Grid Testbed work. This information will be reported to the Commission and Commission staff either through the filing and workshop requirements of UM 2005 or through the stakeholder meetings of the Demand Response Review Committee of the Smart Grid Testbed or through the Smart Grid Testbed reports to the Commission.

Lastly, PGE will be exploring possible changes to our current practice of cost effectiveness through our Flexible Load Plan that we intend to file in early Q1 of 2020. Within the Flexible Load Plan we expect to file a background of our present practice, an analysis of the methodology being used, and an identification of possible changes to the cost effectiveness methodology currently in place. After we have conducted this analysis we intend to present a proposal for cost effectiveness analysis and modeling which builds on the present borrowed methodology from California and is more tailored and specific to the costs and benefits unique to the PGE service territory.

In response to Commission Staff identified Requirement #3 of Order No. 17-446 that requested PGE provide an update to its distribution resource planning efforts as directed through LC 66 and other pertinent dockets PGE offers the following discussion.

This is a time of rapid change for the electric utility industry. Many of those changes are explicitly affecting utility distribution systems. Changing customer expectations regarding their energy service provider, environmental policies, technological advances, electric vehicles and increased demand for smart internet connected devices are reshaping the way in which these services are being provided to customers. PGE's distribution planning team recognizes the changing dynamics of the distribution grid and has undertaken several efforts to address the opportunities and challenges that distribution grid planning and operators face.

Traditional distribution planning has revolved around planning for current and forecasted load in a given area. This area normally included planning by distribution feeder and substation region. PGE understands and recognizes that utilities will need to plan for loads as well as generation moving forward. PGE already is working with different internal customer centric groups to focus on the flexibility that loads and distribution energy resources (DERs) can provide to system planners and operators. For this, PGE needs to account for the numerous ways in which DERs affect the system. To address this, PGE has recently undertaken several technical efforts.

PGE has been engaged with different Advanced Distribution Management System (ADMS) vendors in which the utility has evaluated their products aimed at modeling the distribution system. The ADMS is critical in analyzing real time data that PGE receives from the distribution system and is crucial in providing the visibility and control for planning and operating the grid with significant DER penetrations. This is also central to PGE's new Integrated Operations Center (IOC).

Several projects have been assembled to help PGE with planning for and running the ADMS system, many of which are also being used to improve the data quality of the distribution system. PGE's Geographic Integration Systems, Strategic Asset Management, Enterprise Data Strategy and Distribution Planning teams are working closely together to help model and capture existing DER's in the system. Distribution Planning is currently using these updated distribution models to create and maintain the databases that are utilized to perform distribution planning activities at PGE. PGE uses the CYMDIST software to perform power flow related modeling of the distribution system. These databases are being used to baseline hosting capacity analyses for the distribution system. Initial analyses will capture the effects of DER's based on thermal, voltage, protection and power quality violations.

Also, PGE has been using CYME for distribution planning studies related to Distribution Automation. Additionally, PGE plans to roll out a Field Area Network (FAN) for reliable and accurate Fault Location Isolation Service Restoration (FLISR) that improves customer reliability and helps reduce outage restorage times. PGE expects the ADMS system to be central to implementing the FLISR schemes in the future. PGE is also involved in a pilot project with Kevala Analytics, a software firm, that is helping PGE analyze various DER adoption scenarios and quantify their effects on the distribution system.

Jay Tinker

Jay Tinker
Director, Rates and Regulatory Affairs
Portland General Electric