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

June 2, 2017

Email
puc.filingcenter@state.or.us

Public Utility Commission of Oregon
201 High Street, S.E., Suite 100
P. O. Box 1088
Salem, OR 97308-1088

Attn: Commission Filing Center

Re: **UM 1708 PGE's Reauthorization Application for Deferral of Expenses Associated with Two Residential Demand Response Pilots**

Enclosed for filing is Portland General Electric Company's (PGE) Application for Reauthorization of Deferral Expenses Associated with Two Residential Demand Response Pilots, with an effective date of June 23, 2016.

PGE received authorization to defer expenses through OPUC Order No. 16-292. A notice regarding this reauthorization application has been provided to the parties on the UM 1708 and the UE 319 service lists.

Thank you for your assistance in this matter. If you have any questions or require further information, please call me at (503) 464-8929 or Alex Tooman at (503) 464-7623.

Please direct all formal correspondence, questions, or requests to the following e-mail address pge.opuc.filings@pgn.com.

Sincerely,

for

Stefan Brown
Manager, Regulatory Affairs

Encls
cc: Service Lists: UM 1708 and UE 319

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1708

In the Matter of the Application of Portland General Electric Company for an Order Approving the Deferral of Expenses Associated with two Residential Demand Response Pilots	**Reauthorization Application for Deferral of Expenses Associated with Two Residential Demand Response Pilots**

Pursuant to ORS 757.259 and OAR 860-027-0300, and OPUC Commission Order 15-203, Portland General Electric Company ("PGE") hereby requests approval for the continuance of the deferral for two residential demand response (DR) pilots, i.e., the Pricing Pilot and the Direct Load Control Thermostat (DLCT) Pilot, including deferral of incremental costs associated with developing and operating the pilots projected to run through 2018. PGE seeks reauthorization to defer costs incurred during 2017 and 2018, and requests an effective date of June 23, 2017. PGE will seek amortization of the deferred amounts in a future Commission proceeding.

I. <u>Deferral History</u>

In June 2011, PGE completed its Advanced Metering Infrastructure (AMI) project, as approved by Commission Order No. 08-245. As part of the Proposed AMI Conditions, PGE developed a Residential Critical Peak Pricing (CPP) Pilot (Schedule 12) program that was effective from November 2011 through October 2013.

As directed by the Commission in Order No. 09-395, PGE filed two reports based on the evaluation of the CPP Pilot. In the Conclusions and Recommendations of the final CPP report (filed May 30, 2014), PGE stated that it would "Evaluate and propose additional pilot alternatives that could help PGE develop a CPP program" (at page 6).

PGE identified and researched two residential pilots that would best inform development of future demand response programs. The Pricing pilot provides a comparison to CPP and addresses the lessons learned from that pilot. The DLCT pilot tests enabling technology and PGE's ability to achieve automated load control among residential customers. The Commission approved the deferral and cost recovery through OPUC Order 15-203 on June 23, 2015 and through OPUC Order No. 16-292 on August 2, 2016. PGE seeks reauthorization for deferral of incremental costs associated with the two pilots for the period commencing June 23, 2017 through June 22, 2018.

II. **OAR 860-027-0300 Requirements**

The following is provided pursuant to OAR 860-027-0300(3):

a. Description of utility expense for which deferred accounting is requested.

Pursuant to ORS 757.259 (2) (e), PGE seeks reauthorization of the deferred accounting treatment of the incremental costs associated with the two residential demand response (DR) pilots, the Pricing Pilot and the DLCT. As stated above, PGE requests a reauthorization effective period of June 23, 2017 through June 22, 2018.

Attachment B provides the preliminary evaluation memo of the DLCT pilot. Based on its recommendations, PGE plans to expand the DLCT pilot to include non-Nest thermostats. This expansion will maintain a consistent program design, but will include thermostats from other vendors such as Honeywell and Ecobee. Opening the pilot to these vendors will give PGE a better understanding of the wider market with regard to load impacts and customer experience.

b. Reasons for deferral

See Deferral History above. The granting of this reauthorization will minimize the frequency of rate changes and match appropriately the costs borne by and benefits received by customers. PGE received approval of two reauthorizations through OPUC Order No. 15-203 for the deferral period beginning June 23, 2015, and OPUC Order No. 16 –292, for the deferral period beginning June 23, 2016.

Without reauthorization, the current authorization to defer costs will expire on June 22, 2017. PGE is filing for this reauthorization for the period commencing June 23, 2017 through June 22, 2018. PGE expects any deferred amount to be recovered or refunded in a manner approved by the Commission.

c. Proposed accounting for recording amounts deferred.

PGE proposes to continue to record the deferred amounts as a regulatory asset in FERC account 182.3, Other Regulatory Assets, with a credit to FERC account 456, Other Revenue. In the absence of Commission reauthorization of the two residential DR pilots and of deferred accounting treatment for their costs, PGE would discontinue the pilots.

d. Estimate of amounts to be recorded for the next 12 months.

PGE estimates the total incremental costs of the two residential DR pilots to be approximately $5.7 million as listed in the below table ($000).

Table 1
Cost per Pilot by Year ($000)

Pilot	2015 Actuals	2016 Actuals	2017 Estimate	2018 Estimate	Estimated Totals	Notes
Pricing Pilot	$392,588	$748,847	$835,734	$938,875	$2,916,044	Extended through 12/31/2018
DLCT-Pilot: NEST	$29,076	$332,337	$657,896	$899,435	$1,918,744	Target 12,000 participants by the end of 2018
DLCT-Pilot: Other	$0	$0	$276,500	$564,700	$841,200	Target 3,500 Participants by the end of 2018
Totals	$421,664	$1,081,184	$1,770,131	$2,403,010	$5,675,988	

e. Notice

A copy of the notice of application for reauthorization of the deferred accounting treatment and a list of persons served with this Notice are attached to the Application as Attachment A.

III. The following is provided pursuant to OAR 860-027-0300(4).

a. Description of deferred account entries.

Please see section II (a) and (b) above.

b. The reason for continuing the deferred accounting.

Please see section II (b) above. PGE seeks to continue to defer revenues associated with the approved deferred accounting treatment for the incremental residential DR pilots pursuant to Commission Orders No. 15-203 and 16-292 as described above. Without reauthorization this deferral will expire on June 22, 2017.

IV. Summary of filing conditions[1]

a. Earnings review.

The cost recovery for the two residential DR pilots will be subject to an earnings review in accordance with ORS 757.259(5).

b. Prudence review

PGE will submit two combined reports on the pilots, which will provide third-party evaluations, cost summaries, estimated curtailments, and results of customer satisfaction surveys. The Commission Staff can also review applicable cost details during the pilots' operations (i.e., deferral phase) and/or the proceeding to authorize amortization.

c. Sharing

All prudently incurred costs are to be recoverable by PGE with no sharing mechanism.

d. Rate Spread/Rate Design

The rate spread/rate design will be determined during the proceeding to authorize amortization of the pilots' deferred costs.

[1] Per agreement with the Commission Staff on January 24, 2012.

e. <u>Three percent test (ORS 757.259 (6)).</u>

The amortization of the pilots' deferred costs will be subject to the three percent test in accordance with ORS 757.259(7) and (8), which limits aggregated deferral amortizations during a 12-month period to no more than three percent of the utility's gross revenues for the preceding year.

V. **PGE Contacts**

The authorized addresses to receive notices and communications in respect to this application are:

Douglas C. Tingey Associate General Counsel Portland General Electric 1 WTC1301 121 SW Salmon Street Portland, OR 97204 Phone: 503.464.8926 E-mail: doug.tingey@pgn.com	PGE-OPUC Filings Rates & Regulatory Affairs Portland General Electric 1 WTC 0306 121 SW Salmon Street Portland, OR 97204 Phone: 503.464.8929 E-mail: pge.opuc.filings@pgn.com

In addition to the names and addresses above, the following are to received notices and communications via the e-mail service list:

Alex Tooman, Project Manager, Regulatory Affairs
E-mail: Alex.Tooman@pgn.com

VI. **Conclusion**

For the reasons stated above, PGE requests permission to continue to defer for later ratemaking treatment the expenses associated with the two residential DR pilots, effective June 23, 2017 through June 22, 2018.

DATED this 2nd day of June 2017.

Stefan Brown, Manager
Regulatory Affairs
Portland General Electric Company
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UM 1708

Attachment A

Notice of Application for Reauthorization of Deferral of Expenses Associated with Two Residential Demand Response Pilots

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1708

In the Matter of the Application of Portland General Electric Company for an Order Approving the Deferral of Expenses Associated with two Residential Demand Response Pilots

Notice of Application for Reauthorization of Deferral of Expenses Associated with Two Residential Demand Response Pilots

On June 2, 2017, Portland General Electric Company ("PGE") filed an Application for Reauthorization of Deferral of Expenses Associated with Two Residential Demand Response Pilots with the Oregon Public Utility Commission (the "Commission").

Approval for deferred accounting treatment will not authorize a change in PGE's rates, but will permit the Commission to consider allowing such deferred amounts in rates in a subsequent proceeding.

Persons who wish to obtain a copy of PGE's application will be able to access it on the OPUC website.

Any person who wishes to submit written comments to the Commission on PGE's application must do so no later than July 2, 2017.

Dated: June 2, 2017.

for

Stefan Brown, Manager
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UM 1708

Attachment B

Preliminary Evaluation Memo of the Direct Load Control Thermostat Pilot

CADMUS

MEMORANDUM

To: Josh Keeling and Alex Reedin, Portland General Electric

Cc: Dyon Martin and Roch Naleway, Portland General Electric

From: Scott Reeves and Jim Stewart, Cadmus

Subject: PGE Rush Hour Rewards Findings Summary

Date: December 27, 2016

This memo presents the methodology and findings from Cadmus' evaluation of Portland General Electric's (PGE) smart thermostat pilot program—Rush Hour Rewards (RHR)—for winter 2015/2016 and summer 2016.

Findings Overview

The evaluation produced several key findings regarding the first two seasons:

- ***Program Delivery/Enrollment***. In October 2015, PGE's RHR pilot launched on schedule, quickly surpassing its enrollment targets of 300 heating and 700 cooling participants for 2016. As of September 2016, the program had enrolled 398 heating and 2,492 cooling customers.
- ***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 during winter events and about 0.8 kW per customer during summer events.
- ***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.

Recommendations

Based on evaluation of program performance during the first two pilot seasons, Cadmus offers the following recommendations for consideration:

- RHR impacts on customer peak demand and satisfaction support the continuation and possible expansion of the RHR program. Cadmus did not estimate the cost-effectiveness of the RHR program, but the estimates of demand savings per customer were large and in line with PGE's

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expectations. PGE reported that for a range of assumptions about measure life, the RHR program would prove cost-effective.[1]

- PGE should continue to evaluate the RHR program for a second year, including both summer and winter seasons. PGE could refine its first-year assessment of demand response capacity benefits and cost-effectiveness and identify additional opportunities for improving the program implementation.
- PGE should expand the program to include customers with electric furnaces. Expanding eligibility for the program would provide PGE with additional demand response capacity.
- PGE should expand the program to include customers with other brands of connected thermostats. Expanding eligibility for the program would provide PGE with additional demand response capacity.
- PGE should make improvements to its meter data management system and customer information system to increase its participation tracking and meter data storage and processing capabilities.
- PGE should work with the Energy Trust of Oregon to explore opportunities for achieving energy efficiency savings occurring through this program. Integrating efficiency and peak demand savings may increase the cost-effectiveness of smart thermostat programs and allow the programs to reach low and moderate income customers.

Program Description

In October 2015, PGE launched a smart thermostat pilot program for residential customers who installed a Nest learning thermostat. Nest, the thermostat manufacturer and demand response service provider, markets the program and manages the branded RHR portal for PGE. This portal allows PGE to manage loads during RHR events by adjusting temperature setpoints on participants' Nest thermostats. This primary objective of this pilot evaluation was to measure demand reduction during summer and winter RHR events. Although Nest thermostats may provide energy efficiency savings that occur on peak, this study did not measure these savings.

Outreach and Eligibility

Nest markets the program to residential customers with Nest-brand learning thermostats. Because Nest can communicate with its customers through the thermostat and Nest software, Nest primarily delivers marketing of PGE's RHR program through monthly/seasonal notifications to owners or to those newly purchasing and installing Nest thermostats. Nest thermostats assist in targeting eligible customers by

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1 The cost-effectiveness of RHR depends on retaining participants for long enough to obtain sufficient demand response capacity benefits to cover the programs initial fixed costs, which include one-time incentive payments to customers, PGE investments in computer hardware and software, and set-up fees to program implementers. As smart thermsotat programs are relatively new offerings, there is not much industry data on customer retention.

collecting data about connected HVAC equipment and about customers' heating and cooling profiles, which can be used to identify homes that employ qualifying equipment.

PGE provides significant marketing support for the the program through several mediums, including PGE's program webpage, targeted emails to PGE customers on hot summer days, bill inserts, and social media. PGE's marketing and communication channels generated more than 40% of the traffic to Nest's PGE-specific RHR registration page.

Participants may enroll for the summer season, winter season, or both, depending on their qualifying equipment. Summertime participants must have electric central air conditioning or heat pumps; wintertime participants must have electric forced-air furnaces or heat pumps, although the program primarily enrolled heat pump customers during the first winter season. Nest cannot currently identify electric forced-air furnace customers based on how the Nest thermostat is wired. Verification of an electric forced air furnace requires analysis of the customer's energy use.

Customer Incentives

PGE customers received an incentive of $25 upon enrollment, with additional incentives of $25 per winter/summer season, depending on whether their heating or cooling equipment qualifies. Participants with heat pumps could receive up to $50 per year, while customers with central air conditioning or central electric furnaces receive $25 per year. Customers must participate in at least 50% of RHR events per season to qualify for the seasonal incentive payments.

To verify customers meet criteria to receive incentives, Nest currently provides PGE with a list of active customers and program enrollment dates. PGE then uses these data and the number of overlapping events to calculate incentive payments. Additionally, Nest supplied PGE with a list of customers whose thermostats did not maintain an Internet connection for the event season. Going forward, a more robust verification of customer participation is under development, including a customer retention process to lure customers back into participation as well as an unenrollment process for customers who choose not to participate.

Event Delivery

Once a customer enrolled in RHR, Nest notified the customer of upcoming "Rush Hours" (i.e., demand response events) and of events in progress. Notifications arrived through the Nest app and through an icon that appeared on the thermostat's display. PGE decided when to call events, which were activated using the utility's interface with the Nest RHR platform.

Afternoon events required PGE to notify intent to dispatch the event by 10:00 a.m. on the same day. All morning events required PGE to send dispatch notices by 7:00 p.m. of the previous day. Customers that tried to control their thermostats in a way contrary to the desired response (e.g., setting a lower temperature during a summer event) received a "speedbump" notification, reminding them that an electricity "Rush Hour" was in effect, and asking them to confirm that they wanted to change their setpoints (though this did not prevent them from doing so).

Nest algorithms determined the specific load control response of each customer's thermostat, based on the household's usage profile (as recorded by the Nest thermostat). If the algorithm deemed it efficient, the thermostat preconditioned the home for up to an hour in advance of an event. Note that preconditioning was not efficient for homes with usage profiles indicating a high thermal loss rate.

The Public Utility Commission of Oregon requires PGE to call a minimum of six events per season (though PGE may call up to 10 events), with events scheduled to last three consecutive hours and occurring on weekday (non-holiday) afternoons, when seasonal weather increases peak demand (i.e., on cold days during winter and warm days during summer).

Event Schedule

Table 1 shows the event days, times, and average temperatures for the summer and winter seasons.

Table 1. RHR Seasonal Event Dates and Times*

Event	Winter			Summer		
	Date	Hours	Avg. Event Temp.	Date	Hours	Avg. Event Temp.
1	Dec 29	4:00 p.m. - 7:00 p.m.	38	Jul 27	4:00 p.m. - 7:00 p.m.	86
2	Dec 30	4:00 p.m. - 7:00 p.m.	36	Jul 29	4:00 p.m. - 7:00 p.m.	89
3	Jan 4	4:00 p.m. - 7:00 p.m.	34	Aug 4	4:00 p.m. - 7:00 p.m.	87
4	Jan 6	4:00 p.m. - 7:00 p.m.	39	Aug 11	4:00 p.m. - 7:00 p.m.	87
5	Feb 1	4:00 p.m. - 7:00 p.m.	44	Aug 12	4:00 p.m. - 7:00 p.m.	93
6	Feb 9	7:00 a.m. - 10:00 a.m.	45	Aug 18	4:00 p.m. - 7:00 p.m.	94
7	Feb 17	5:00 p.m. - 8:00 p.m.	50	Aug 19	4:00 p.m. - 7:00 p.m.	95
8	Feb 26	5:00 p.m. - 8:00 p.m.	50	Aug 25	4:00 p.m. - 7:00 p.m.	90
9				Aug 26	3:00 p.m. - 6:00 p.m.	94

*This analysis excludes one early summer season event (June 6, 2016) given that participating customers not yet been assigned to treatment or control groups at the time.

Research Objectives

PGE outlined the following objectives related to pilot delivery and evaluation research:

- Implement the program over five seasons (i.e., winter 2016, summer 2016, winter 2017, summer 2017, winter 2018), with six to 10 events per season
- Measure the impact of events on customers' comfort and satisfaction
- Measure the demand reduction capacity, any preconditioning or rebound effects, and cost-effectiveness
- Determine the best strategies for scaling the pilot program into a mass market program
- Achieve positive customer experiences

This memo focuses on reporting load impacts and findings, drawn from customer surveys from the first winter and summer seasons. Although smart thermostats may provide energy savings, this pilot evaluation did not seek to measure energy savings.

Methodology

Research Design

To estimate thermostat controls' impacts, Cadmus worked with PGE to implement the pilot as a randomized control trial (RCT).[2] The RCT involved randomly assigning program participants (i.e., residential customers with Nest thermostats meeting eligibility requirements) to a treatment group or a control group. Treatment group customers experienced RHR load control events, while control group customers did not. An RCT, serving as the gold standard in program evaluation, was expected to produce an unbiased estimate of the pilot's impacts on energy demand.

Cadmus randomly assigned 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 the following data sources in performing the analysis:

- ***Participant enrollment data***, provided by PGE, tracked enrollment for treatment group and control group customers. These data included participant name, contact information (e.g., address), a unique customer identifier (i.e., point of delivery [POD] ID), and an enrollment date.
- ***Interval consumption data***, provided by PGE for all enrolled participants. For post-enrollment periods, these included watt-hour electricity consumption at 15-minute-intervals, measured useing advanced metering infrastructure (AMI) meters. For historical usage periods (prior to enrollment), only hourly data were available. The pre-enrollment data recorded customer kWh consumption (Watt hours truncated at the thousands place) from December 2014 through September 2016.
- ***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.

Customer Enrollment and Random Assignment

Since PGE's launch of RHR, customers have continuously enrolled in the pilot. Initially, PGE targeted enrollment of 300 winter-season participants (with heat pumps or electric heat) and 700 summer-season participants (using heat pumps or central air conditioning). By the summer season's end, the program had enrolled 398 winter participants and 2,492 summer participants.

At the beginning of each season, Cadmus randomly assigned all program participants to the treatment group or control group, and then used pretreatment monthly consumption data and post-treatment

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[2] This design followed recommendations by the *U.S. Department of Energy's Uniform Method Project Behavior-Based Program Evaluation Protocols* and EPRI's *Consumer Behavior Study Evaluation Guidelines.*

consumption data on non-event days to verify that the changes did not result in statistically significant electric consumption differences between the randomized treatment and control groups. Customers signing up after initial random assignments were randomly assigned on a rolling basis to the treatment or the control group.[3]

Savings Estimation

Cadmus performed a difference-in-differences panel regression analysis of the hourly energy consumption of treatment and control group customers to estimate the RHR load impacts. The analysis compared the average consumption change between event and non-event hours for treatment group customers, with the average consumption change between event and non-event hours for control group customers. Cadmus estimated the impacts in the two hours before, three hours during, and eight hours after each event. The regression included independent variables for customer pre-treatment consumption, customer demand for heating or cooling (i.e., heating degree hours or cooling degree hours), the hour of the day, and the day of the week. The regression analysis will likely result in an unbiased estimate of load control impacts due to random assignment of customers to treatment. This memo's appendix presents the specific model used to estimate these impacts.

Participant Surveys

Cadmus administered several surveys to assess customers' experiences. These included the following:

- A baseline survey to assess customer recruitment (fielded during enrollment);
- An event survey to assess customer awareness, thermal comfort, and behaviors during RHR events
- An end-of-season survey design to assess overall program experience.

These surveys asked customers about their satisfaction with the program, their perceptions about marketing effectiveness, their motivations for and barriers to participating, awareness of demand response and RHR events, and energy-use attitudes and behaviors about space heating and cooling. The surveys also included a battery of demographic questions.

Analysis Sample

Data Screening

Starting with a census treatment and control group participants, Cadmus excluded the following customers from the analysis sample:

- Customers who could not be matched to AMI data
- Net-metering customers

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[3] Using a power analysis, Cadmus determined the appropriate sample sizes to detect the program's impact. As enrollment increases, Cadmus will reassess these thresholds prior to making seasonal reassignments and allocations of the minimum control group sizes required to detect the expected impacts.

- Customers without consumption data reported to watt-hours (i.e., kWh to three decimal places) during the treatment period[4]

Table 2. Sample Disposition—Winter

Screen	Treatment		Control		Overall	
	Accounts Remaining	Percent Remaining	Accounts Remaining	Percent Remaining	Accounts Remaining	Percent Remaining
Original PODIDs*	104	100%	131	100%	235	100%
Matched to Consumption Data	104	100%	131	100%	235	100%
Net Metering Customers	104	100%	131	100%	235	100%
Insufficient kW data (e.g., integer values)**	85	82%	107	82%	193	82%
Final Analysis Group	**85**	**82%**	**107**	**82%**	**193**	**82%**

*Original PODIDs reflect total enrolled customers participating in at least one seasonal event.

**Given continuous program enrollment and event-specific attrition (due to insufficient meter data during specific event hours), the number of customers with valid data varied between event hours. This value represented the maximum, where event-specific attrition ranged from 22 to 30 customers for the treatment group and from 28 to 40 customers for the control group.

Table 3. Sample Disposition—Summer

Screen	Treatment		Control		Overall	
	Accounts Remaining	Percent Remaining	Accounts Remaining	Percent Remaining	Accounts Remaining	Percent Remaining
Original PODIDs*	1,577	100%	915	100%	2,492	100%
Matched to Consumption Data	1,559	99%	901	98%	2,460	99%
Net Metering Customers	1,549	98%	892	97%	2,441	98%
Missing 2015 data	1,519	96%	857	94%	2,376	95%
Insufficient kW data (e.g., integer values)**	1,436	91%	790	86%	2,226	89%
Final Analysis Group	**1,436**	**91%**	**790**	**86%**	**2,226**	**89%**

*Original PODIDs reflect total enrolled customers participating in at least one seasonal event.

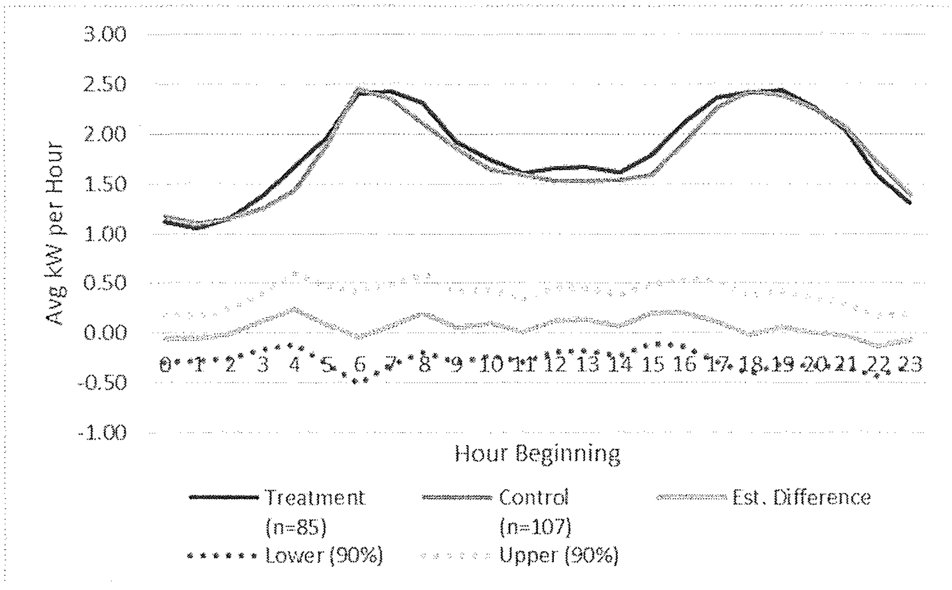
**Given continuous program enrollment and event-specific attrition (occurring due to insufficient meter data during specific event hours), the number of customers with valid data varied between event hours. This value represented the maximum, while event-specific attrition ranged from 121 to 162 customers for the treatment group and 87 to 128 customers for the control group.

Figure 1 and Figure 2 compare average hourly consumption for treatment and control group customers on non-holiday, non-event weekday hours during each season. Cadmus did not find statistically

4 Prior to program enrollment, customer meters recorded kW-hour interval consumption at integer values. Upon program enrollment, PGE attempted to switch customer meters to record watt-hour interval consumption to three decimal places. Due to communication problems, however, not all customer meters switched over.

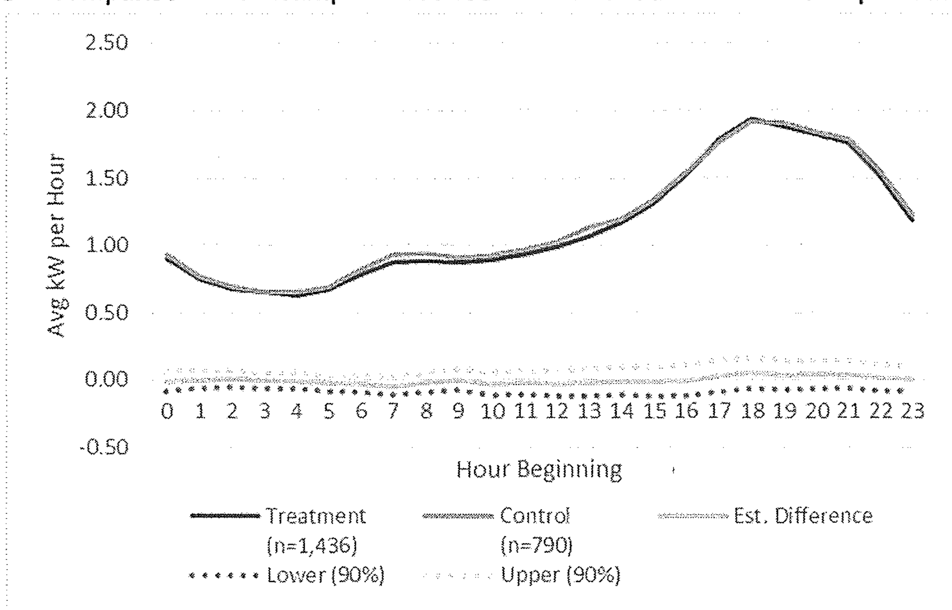
significant differences in consumption during any hours of the winter or summer seasons. This suggests that the randomization resulted in well-balanced treatment and control groups.

Figure 1. Comparison of Consumption Between Treatment and Control Groups—Winter*



Note: The figure shows average consumption per customer, per hour, on non-event, non-holiday weekday hours for randomly assigned treatment and control groups.

Figure 2. Comparison of Consumption between Treatment and Control Groups—Summer*



Note: The figure shows average consumption per customer, per hour, on non-event, non-holiday weekday hours for randomly assigned treatment and control groups.

Impact Findings

Figure 3 and Figure 4 show estimates of average load impacts per hour, per treatment group customer for winter and summer RHR events. The figures show average impact estimates by season (i.e., winter and summer) and event start times due as estimated baselines and load impacts depend on the hour-of-day.

Figure 3. Average Winter Season Impacts, by Event Start Time

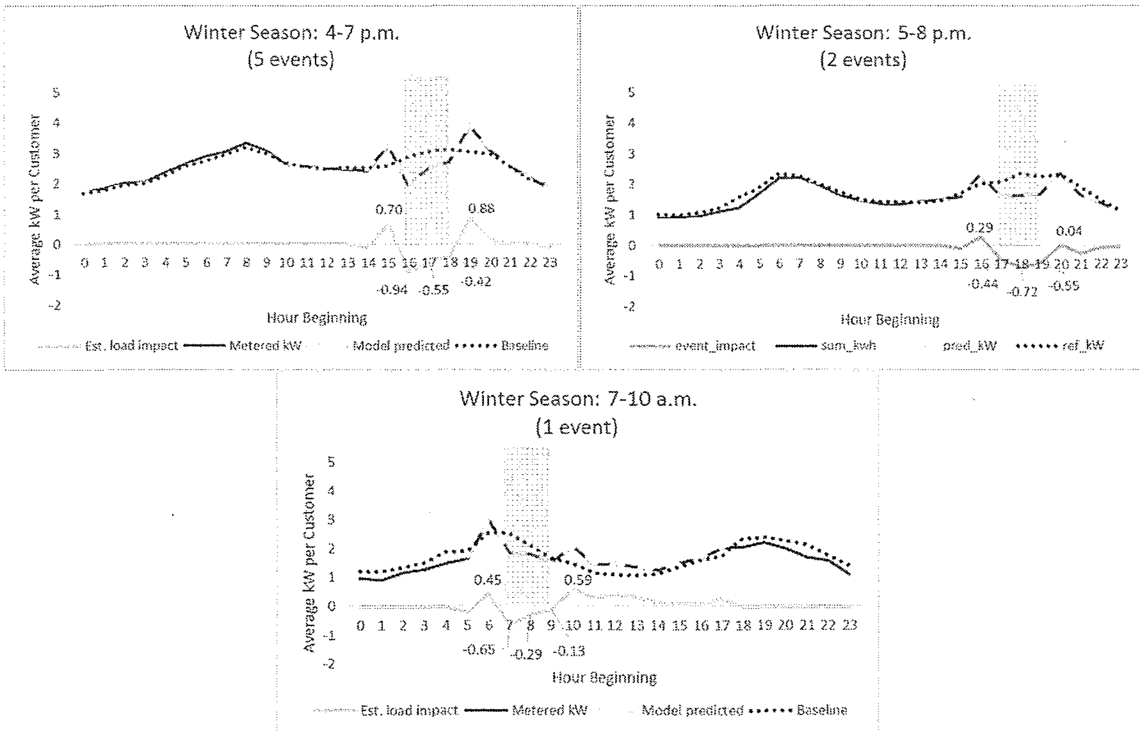
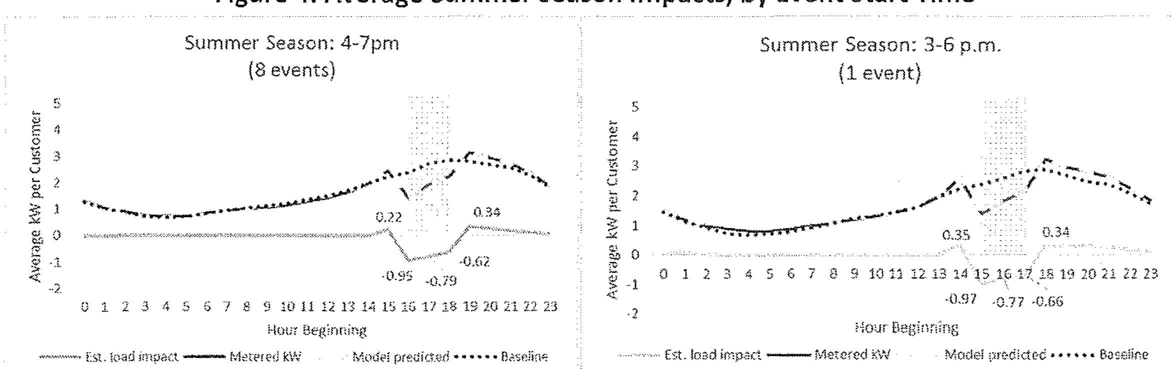


Figure 4. Average Summer Season Impacts, by Event Start Time



During winter, events started at 7:00 a.m., 4:00 p.m., or 5:00 p.m. During summer, events started at 3:00 p.m. or 4:00 p.m. This document's appendix reports estimates of average load impacts per customer for each hour of each event.

Table 4 provides estimated impacts in a table.

Table 4. PGE RHR Impact Summary, by Season and Event Starting Time*

Event Hour	Winter (kW per customer)			Summer (kW per customer)	
	4:00 p.m. - 7:00 p.m. (5 events)	5:00 p.m. - 8:00 p.m. (2 events)	7:00 a.m. - 10:00 a.m. (1 event)	4:00 p.m. – 7:00 p.m. (8 events)	3:00 p.m. – 6:00 p.m. (1 event)
Pre Hour 1	0.70	0.29	0.45	0.22	0.35
Event Hour 1	***-0.94***	***-0.44***	***-0.65***	***-0.95***	***-0.97***
Event Hour 2	***-0.55***	***-0.72***	***-0.29***	***-0.79***	***-0.77***
Event Hour 3	***-0.42***	***-0.55***	***-0.13***	***-0.62***	***-0.66***
Post Hour 1	0.88	0.04	0.59	0.34	0.34
Post Hour 2	0.16	-0.26	0.29	0.25	0.29
Post Hour 3	0.01	-0.07	0.40	0.18	0.33
Post Hour 4	0.01	-0.04	0.31	0.10	0.26
Avg. kW Reduction	**-0.64**	**-0.57**	**-0.36**	**-0.79**	**-0.80**
Avg. kWh Reduction**	**-0.15**	**-1.75**	**0.97**	**-1.27**	**-0.83**
Min kW	**-0.42**	**-0.44**	**-0.13**	**-0.62**	**-0.66**
Max kW	**-0.94**	**-0.72**	**-0.65**	**-0.95**	**-0.97**

*All winter and summer event hour impacts were significant at the 5% level, except for hours 2 and 3 for the 7:00–10:00 a.m. event.

**These estimates represent the average energy impact per customer, per event, including the hour immediately preceding the first event hour and the four hours immediately following the last event hour.

The RHR program achieved large demand reductions during summer and winter events. Depending on event start times, load reductions averaged from 0.4 kW and 0.6 kW per customer in winter. Load reductions averaged about 0.8 kW per customer in summer. Based on the participation in each event and the estimates of kWh savings per customer per event, the program achieved total kWh savings of 16,999 kWh for summer and 305 kWh for winter.

Typically, the first event hour yielded the largest demand reductions. During winter, the load reduction during the first event hour averaged between 0.4 kW and 0.9 kW per customer. During summer, the first-hour load reduction per customer averaged about 1 kW per customer. Only winter events initiated at 5:00 p.m. achieved higher average load reductions during the second event hour (0.7 kW per customer) than the first event hour (0.4 kW per customer). For all other event starting times, 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.[5]

As expected, RHR pre-cooling or pre-heating during the hour immediately preceding the first event hour increased consumption above baseline. During winter, pre-heating increased average demand per customer between 0.3 and 0.7 kW. During summer, pre-cooling raised average demand per customer between 0.2 and 0.4 kW.

Consumption rebounded when events ended, given heating or air conditioning units operated to return the homes to their programmed temperature setpoints. During winter, rebound increased average demand per customer between 0.6 kW and 0.8 kW during the first hour. During summer, rebound increased average demand by about 0.3 kW. In general, rebound lasted one or two hours.

Table 5 presents the estimated impacts as a percentage of baseline demand.

Table 5. PGE RHR Impact Summary—Percent Reduction, by Season and Event

Event Hour	Winter			Summer	
	4:00 p.m.- 7:00 p.m. (5 events)	5:00 p.m. - 8:00 p.m. (2 events)	7:00 a.m. - 10:00 a.m. (1 event)	4:00 p.m.- 7:00 p.m. (8 events)	3:00 p.m. - 6:00 p.m. (1 event)
Pre Hour 1	27%	14%	17%	10%	15%
Event Hour 1	***-33%***	***-21%***	***-26%***	***-40%***	***-41%***
Event Hour 2	***-18%***	***-30%***	***-14%***	***-29%***	***-30%***
Event Hour 3	***-13%***	***-24%***	***-8%***	***-22%***	***-23%***
Post Hour 1	29%	2%	39%	12%	12%
Post Hour 2	5%	-13%	25%	10%	11%
Post Hour 3	0%	-4%	36%	7%	13%
Post Hour 4	1%	-3%	29%	5%	11%
Avg. Event % Reduction	**-21%**	**-25%**	**-16%**	**-30%**	**-31%**

During winter, the RHR pilot reduced average demand by 20%–33% during the first event hour, 15%–30% during the second event hour, and about 10%–25% during the third event hour. During summer, the pilot reduced demand by about 40% during the first event hour, 30% during the second event hour, and 20% during the third event hour. Pre-cooling or pre-heating during the hour preceding

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5 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.

the first event hour increased demand by 10%–30%. After most events ended, demand rebounded 10%–40% above expected levels.

Planning Assumptions

Cadmus recommends that for resource planning purposes PGE should assume an average demand reduction of 0.7 kW per RHR customer at the meter for winter and 0.8 kW per RHR customer at the meter for summer.[6] This recommendation assumes:

- In winter, future events will be called on non-holiday weekdays between 4:00 p.m. and 7:00 p.m.
- In summer, future events will be called on non-holiday weekdays between 4:00 p.m. and 7:00 p.m.
- Outside temperatures during future RHR events will be similar to those experienced during RHR events in winter 2015/2016 and summer 2016.
- Future RHR program participants will have space heating and cooling equipment similar to that of participants in 2015 and 2016.
- Nest will implement the RHR program similarly in the future.

When applying these capacity assumptions, PGE should keep in mind the following:

- The recommended assumptions do not account for energy losses from transmission and distribution. Accounting for line losses of 7% would marginally increase the assumed impacts to 0.75 kW per RHR customer for winter and 0.85 kW per RHR customer for summer.
- The recommended assumptions represent the approximate average impact across the three hours of a RHR event. It is expected that the load reduction during the first hour will be largest and the load reduction during the third hour will be smallest. For example, in summer, PGE may achieve a load reduction greater than 0.8 kW per customer during the first hour and less than 0.8 kW during the third hour.

Cadmus recommends that PGE update its planning assumptions after evaluating the RHR program in winter 2016/2017 and summer 2017.

Customer Experience Findings

Throughout the pilot, survey response rates proved to be extremely high, with each survey yielding a 50% or higher response rate.

Customer Satisfaction

An important question concerns RHR's effect on customer satisfaction, regarding the program and PGE. Figure 5 and Figure 6 show customer satisfaction ratings for treatment and control groups .[7]

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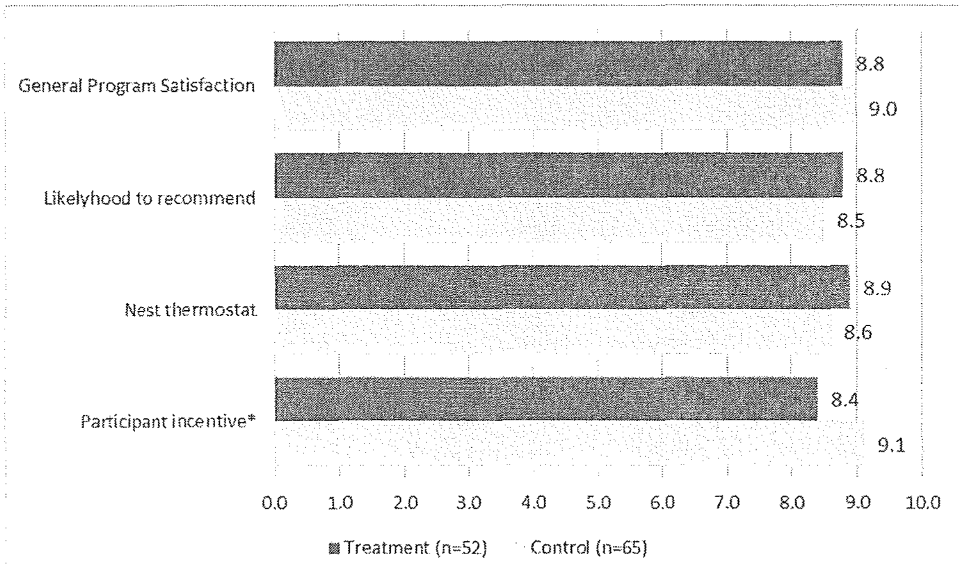
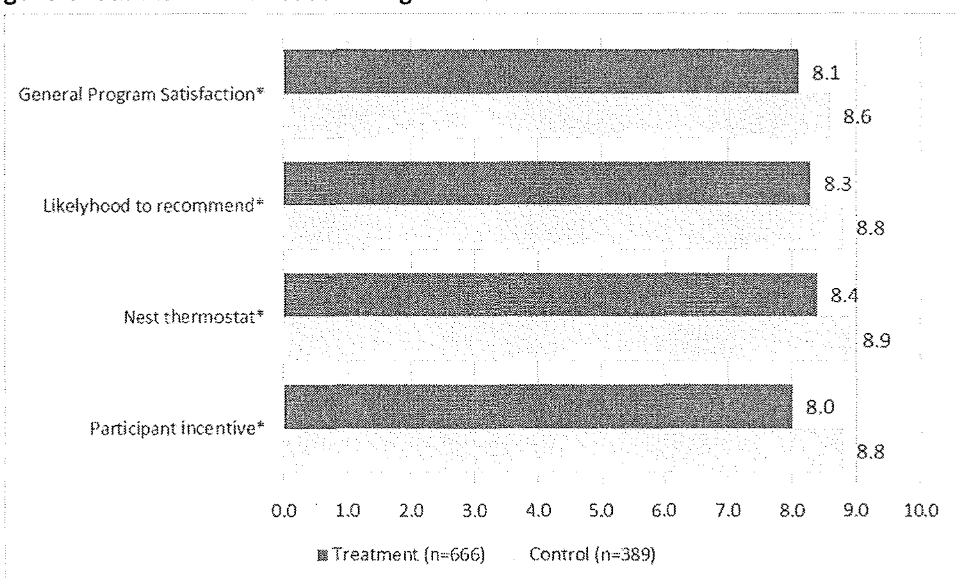
[6] These estimates are based on the average impacts during the 4 p.m. to 7 p.m. periods for both winter and summer seasons, as these were the most frequent event hours.

Figure 5. Winter Post-Season Program Satisfaction and Likelihood to Recommend



*Statistically significant difference between treatment and control groups with 90% confidence.

Figure 6. Summer Post-Season Program Satisfaction and Likelihood to Recommend



*Statistically significant difference between treatment and control groups with 90% confidence.

RHR participants rated the program very positively. In winter and summer, the RHR program, Nest thermostat, and incentives received high average ratings of 8 or greater on a 10-point scale from treatment and control group customers.

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7 The recruitment surveys did not include these ratings because, at that time, participants had neither yet received program treatment assignments nor experienced program activity.

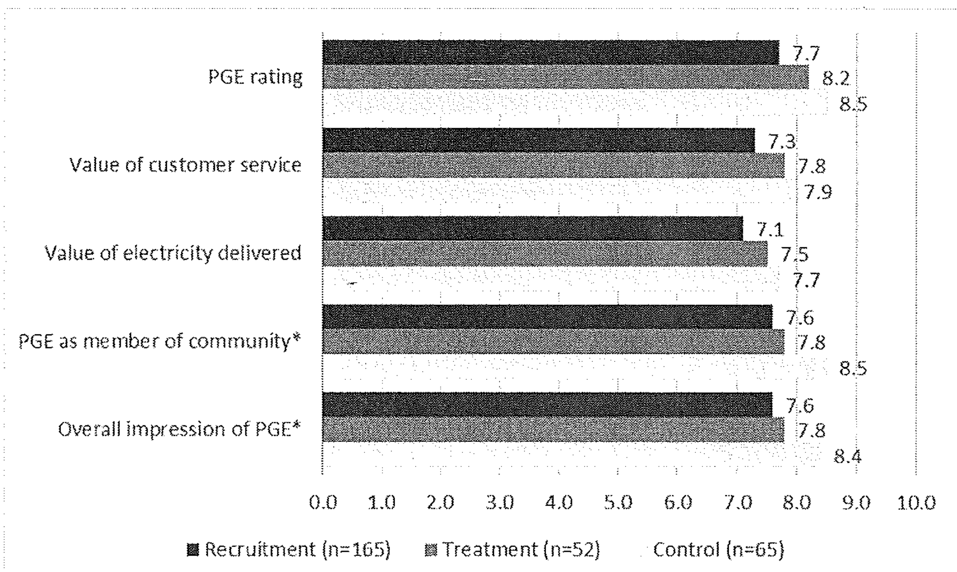
In winter, a clear pattern did not emerge for customer satisfaction between treatment and control group customers. Treatment group customers were more likely to recommend the program and to rate the Nest thermostat higher, but the only statistically significant difference was with satisfaction with the program incentive.

In summer, control group customers rated the program more highly in each category than treatment group customers. All differences were statistically significant. The control group awarded ratings about 0.5 points higher than did the treatment group.

In both winter and summer, incentive payments prompted the greatest satisfaction difference between treatment and control groups. This substantial difference may reflect control customers receiving participation benefits (i.e., the incentives) without experiencing the costs (i.e., temporary loss of thermostat control).

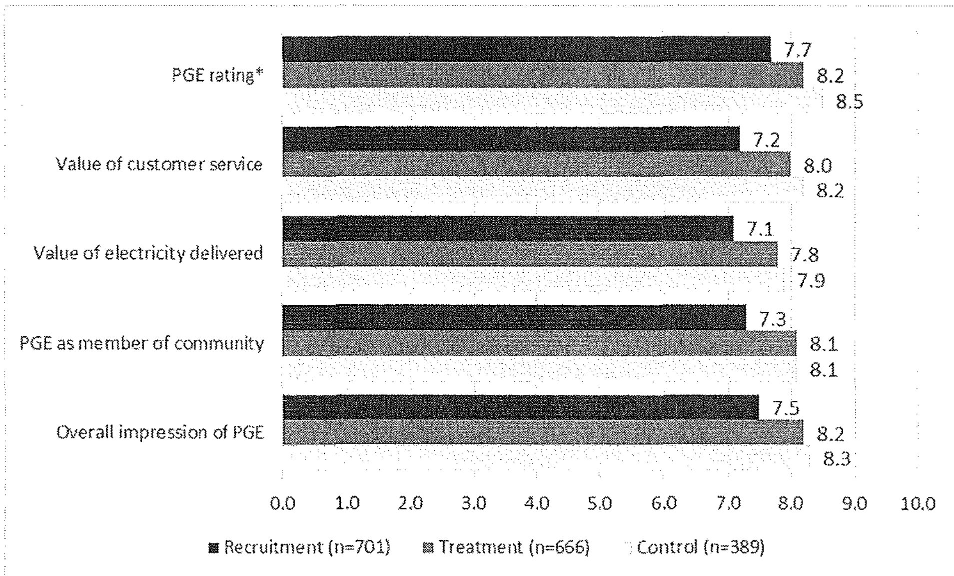
Figure 7 (winter participants) and Figure 8 (summer participants) show satisfaction with PGE ratings, beginning from the recruitment period (after enrollment but before events began) and after the event season. The figures shows separate post-season ratings for the treatment and control groups.

Figure 7. Winter Pre- and Post-Season Satisfaction with PGE



*Statistically significant difference between treatment and control groups with 90% confidence.

Figure 8. Summer Pre- and Post-Season Satisfaction with PGE



*Statistically significant difference between treatment and control groups with 90% confidence.

Customers gave PGE high satisfaction ratings. Though satisfaction became higher after participating, without surveys of nonparticipant customers, it is difficult to determine whether this increase represents a program effect or another time-varying factor.

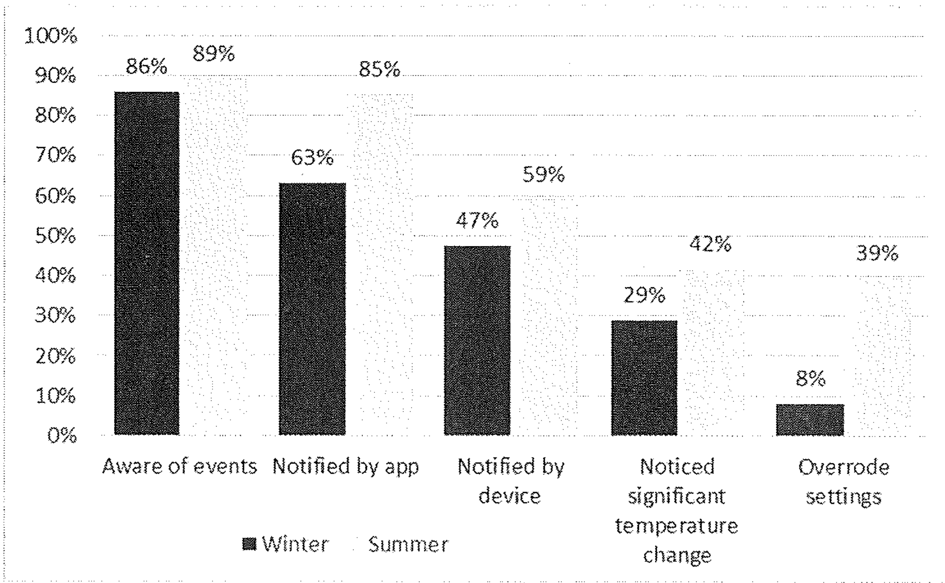
In every category, the control group rated PGE at least as high as the treatment group. Many of the differences, however, were small and statistically insignificant, suggesting that participating in the treatment group did not significantly diminish satisfaction levels.

Awareness and Behavioral Response to Events

Figure 9 compares event awareness and behavioral responses of treatment group customers for the winter and summer seasons.[8] Awareness of RHR events achieved almost 90% for both summer and winter. Summer participants proved more likely to recall notifications by app and the device icon, and were more likely to notice a temperature change and to override an event.

[8] Winter results derive from a survey of 50 treatment group customers, conducted immediately following a February 2016 RHR event. Summer results came from a survey of 666 treatment group customers after the season's end. Both surveys asked similarly worded customer-experience questions about the season and not about specific events.

Figure 9. Awareness and Response to Events in Winter and Summer



When asked if households took actions to keep warm during winter events, 41% of respondents reported putting on warmer clothes, 3% reported using secondary heating equipment, and 3% reported using the fireplace. When asked if the household did anything to keep cool during typical summer events, 33% of respondents reported wearing lighter or less clothing, 25% drank cool beverages, 24% moved to a cooler part of the house, and 21% turned on electric fans. Fewer than 1% of respondents turned on room air conditioners.

Appendix

Regression Model Specification

Cadmus used the following model specification to determine event-specific demand savings.

Equation 1

$$kWh_{it} = \sum_{k=0}^{23} \beta_k Hour_{kt} + \sum_{k=0}^{23} \gamma_k Hour_{kt} * DH_{it} + \sum_{k=0}^{23} \mu_k Hour_{kt} * PreTPeakkWh_{it} + \sum_{m=1}^{M} \sum_{j=1}^{3} \pi_{mj}\, I(Event = 1)_{mjt} + \sum_{m=1}^{M} \sum_{j=1}^{3} \theta_{mj}\, I(Treat = 1)_i * I(Event = 1)_{mjt} + \sum_{m=1}^{M} \sum_{n=1}^{N} \varphi_{mn}\, I(PostEvent = 1)_{nmt} + \sum_{m=1}^{M} \sum_{n=1}^{N} \delta_{mn}\, I(Treat = 1)_i * I(PostEvent = 1)_{nmt} + \sum_{m=1}^{M} \sum_{l=1}^{L} \omega_{ml}\, I(PreEvent = 1)_{mlt} + \sum_{m=1}^{M} \sum_{l=1}^{L} \rho_{ml}\, I(Treat = 1)_i * I(PreEvent = 1)_{mlt} + \varepsilon_{it}$$

Where:

kWh_{it} = Electricity consumption in kWh of customer *i* during hour *t*.

$Hour_{kt}$ = Indicator variable for hour of the day. The variable equals one if hour t is the kth hour of the day, k=0, 1, 2, ..., 23, and equals zero, otherwise.

β_k = Average load impact (kWh/hour) per customer of hour *k* on customer consumption.

DH_{it} = Heating or cooling degree hour for customer *i* in hour *t* for a given base temperature.

γ_k = Average effect per customer of a cooling degree hour on customer consumption in hour k.

μ_k = Average effect per customer of peak pre-treatment consumption on customer consumption in hour k.

$PreTPeakkWh_{it}$ = Average peak consumption per hour of customer i during the pre-treatment period.

$I(Event=1)_{mjt}$ = Indicator variable for RHR event hour. This variable equals one if hour t is the jth hour, j=1,2,...,3, of event m, m=1, 2, ..., M, where M=8 for winter and M=9 for summer, and equals zero otherwise.

π_{mj} = Average load impact (kWh/hour) per customer during hour j of RHR event m. This load impact affects treatment and control group customers.

$I(Treat=1)_i$ = Indicator variable for assignment to treatment group. This variable equals one if customer I was randomly assigned to the treatment group and equals zero otherwise.

θ_{mj} = Average load impact (kWh/hour) per treatment group customer during hour j of RHR event m.

φ_{mn} = Average load impact (kWh/hour) per customer during post-event hour n of event m. This load impact affects treatment and control group customers.

$I(PostEvent=1)_{nmt}$ = Indicator variable for post-event hour. This variable equals one if hour t is the nth hour after the event, n=1,2,...,N, of event m, m=1, 2, ..., M, and equals zero otherwise.

δ_{mn} = Average load impact (kWh/hour) per treatment group customer during post-event hour n of event m.

ω_{ml} = Average load impact (kWh/hour) per customer during pre-event hour l of event m. This load impact affects treatment and control group customers.

$I(PreEvent=1)_{mlt}$ = Indicator variable for pre-event hour. This variable equals one if hour t is the lth hour before the event, l=1,2,...,L, of event m, m=1, 2, ..., M, and equals zero otherwise.

ρ_{ml} = Average load impact (kWh/hour) per treatment group customer during pre-event hour l of event m.

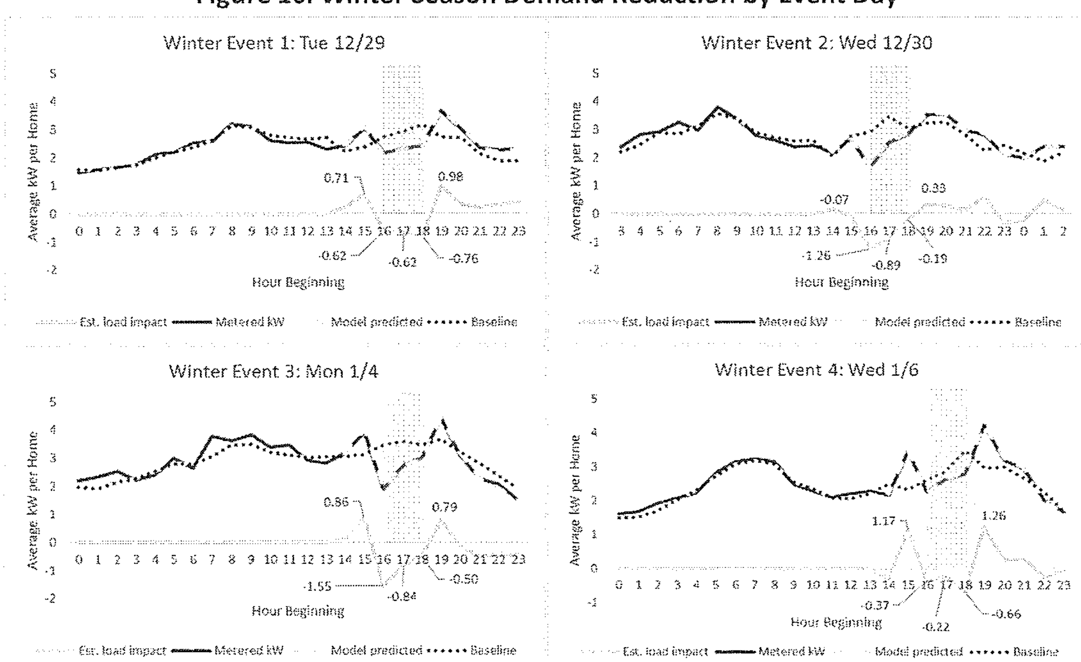
ε_{it} = Random error for customer i in hour t.

Cadmus estimated the panel model by ordinary least squares, clustering the standard errors on customers to allow within-customer correlation of hourly electricity consumption.

Detailed Impact Results

Figure 10 and Figure 11 provide detailed specific-event day impacts for the winter and summer seasons, respectively.

Figure 10. Winter Season Demand Reduction by Event Day



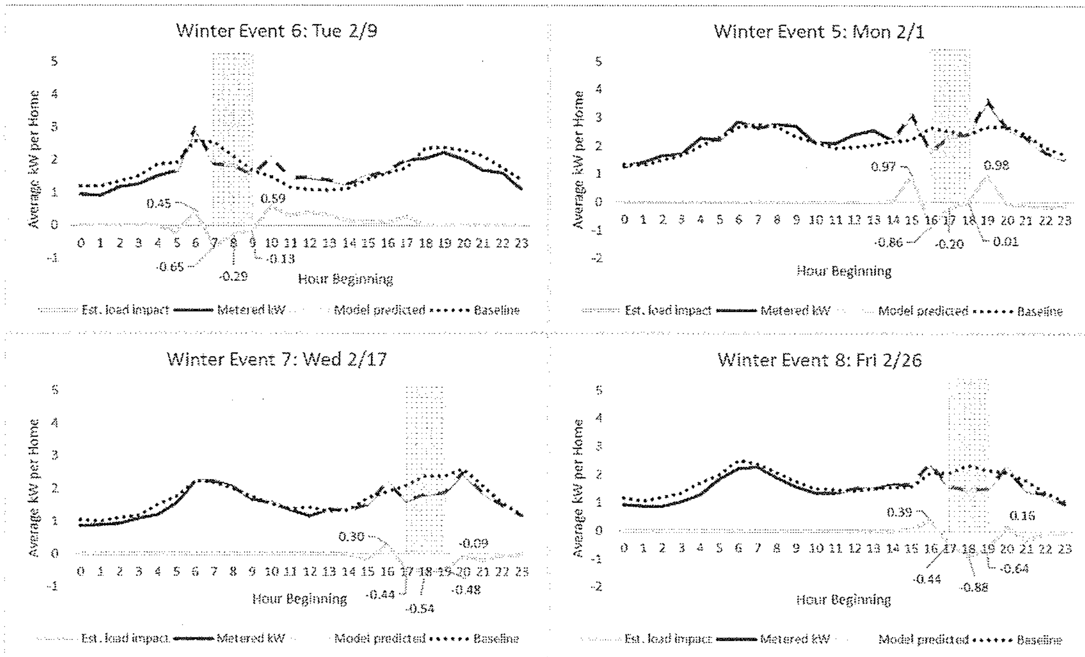
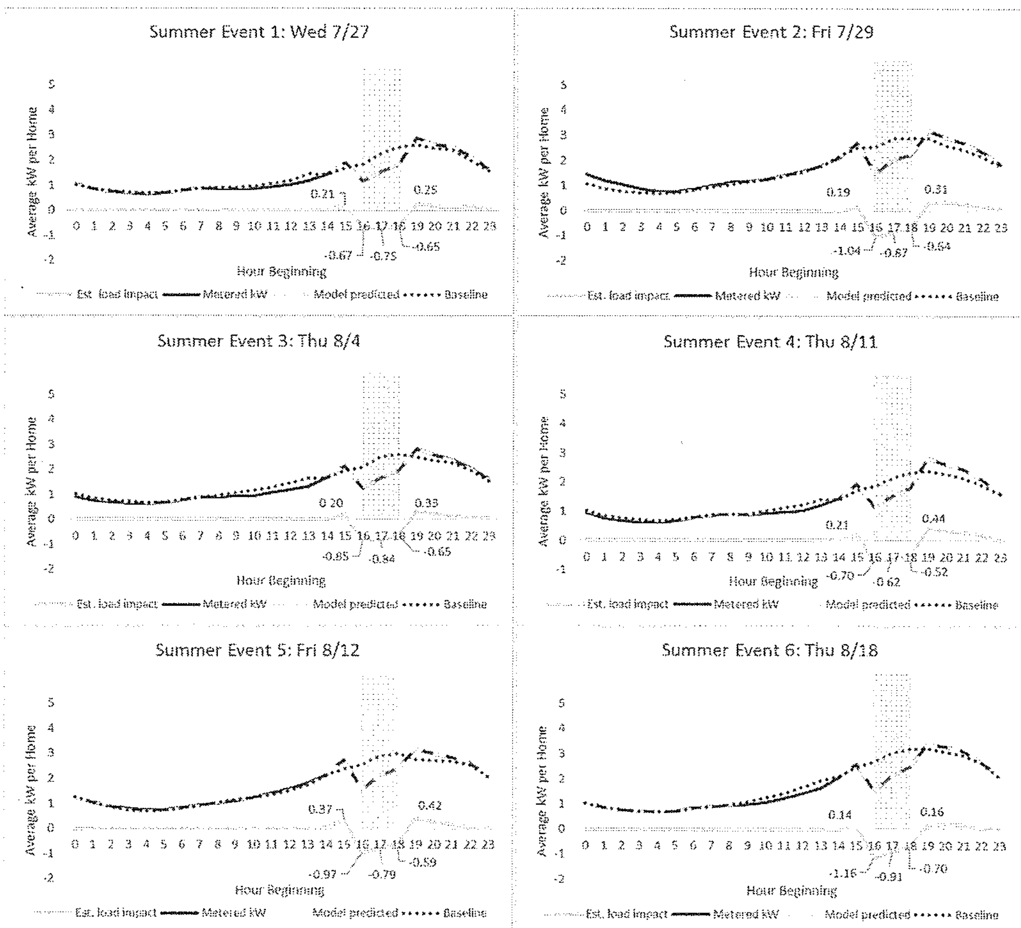
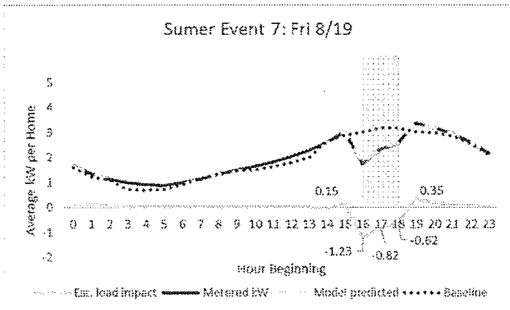
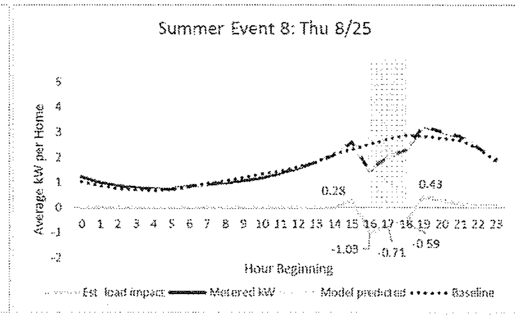


Figure 11. Summer Season Demand Reduction by Event Day







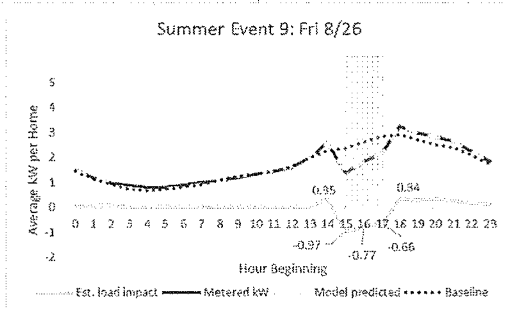


Table 6 provides additional model details regarding hourly demand impacts occurring on summer event days. As noted, the more extreme weather days (events 6 and 7) saw larger demand reductions during the first hours (over 1 kW), but decreased by nearly half by the third hour. Largely due to the increase in sample size, all event hour estimates for the summer season were statistically significant at 10%.

Table 6. Summer Hourly Impacts by Event

Event	Date	Hour	Hour Type	Outside Temp. (°F)	Estimated Impact (kW)	SE Estimated Impact (kW)	Significant at 10%	Metered (kW)	Predicted (kW)	Baseline (kW)
1	27-Jul-16	15	Pre-Hr 1	89	0.209	0.066	Yes	1.88	1.88	1.67
1	**27-Jul-16**	**16**	**Event Hr 1**	**88**	**-0.67**	**0.06**	**Yes**	**1.15**	**1.16**	**1.83**
1	**27-Jul-16**	**17**	**Event Hr 2**	**87**	**-0.75**	**0.07**	**Yes**	**1.53**	**1.53**	**2.28**
1	**27-Jul-16**	**18**	**Event Hr 3**	**84**	**-0.65**	**0.07**	**Yes**	**1.85**	**1.85**	**2.51**
1	27-Jul-16	19	Post-Hr 1	78	0.251	0.071	Yes	2.86	2.86	2.61
1	27-Jul-16	20	Post-Hr 2	75	0.156	0.067	Yes	2.63	2.63	2.47
1	27-Jul-16	21	Post-Hr 3	72	0.101	0.066	No	2.51	2.51	2.41
1	27-Jul-16	22	Post-Hr 4	69	0.167	0.059	Yes	2.14	2.14	1.98
1	27-Jul-16	23	Post-Hr 5	67	0.048	0.050	No	1.61	1.62	1.57
1	28-Jul-16	0	Post-Hr 6	66	0.018	0.043	No	1.24	1.24	1.22
1	28-Jul-16	1	Post-Hr 7	63	0.015	0.034	No	0.98	0.98	0.96
1	28-Jul-16	2	Post-Hr 8	61	0.001	0.029	No	0.88	0.88	0.88
2	29-Jul-16	15	Pre-Hr 1	94	0.188	0.080	Yes	2.69	2.69	2.51
2	**29-Jul-16**	**16**	**Event Hr 1**	**93**	**-1.04**	**0.07**	**Yes**	**1.49**	**1.49**	**2.54**
2	**29-Jul-16**	**17**	**Event Hr 2**	**89**	**-0.87**	**0.08**	**Yes**	**2.03**	**2.04**	**2.90**
2	**29-Jul-16**	**18**	**Event Hr 3**	**84**	**-0.64**	**0.08**	**Yes**	**2.25**	**2.25**	**2.90**

Event	Date	Hour	Hour Type	Outside Temp. (°F)	Estimated Impact (kW)	SE Estimated Impact (kW)	Significant at 10%	Metered (kW)	Predicted (kW)	Baseline (kW)
2	29-Jul-16	19	Post-Hr 1	78	0.312	0.076	Yes	3.20	3.21	2.89
2	29-Jul-16	20	Post-Hr 2	73	0.335	0.073	Yes	2.93	2.93	2.59
2	29-Jul-16	21	Post-Hr 3	70	0.264	0.068	Yes	2.69	2.68	2.42
2	29-Jul-16	22	Post-Hr 4	67	0.171	0.064	Yes	2.33	2.33	2.15
2	29-Jul-16	23	Post-Hr 5	65	0.082	0.058	No	1.84	1.84	1.76
2	30-Jul-16	0	Post-Hr 6	63	0.091	0.048	Yes	1.41	1.42	1.33
2	30-Jul-16	1	Post-Hr 7	60	0.067	0.041	Yes	1.12	1.12	1.06
2	30-Jul-16	2	Post-Hr 8	60	0.019	0.036	No	0.94	0.94	0.92
3	4-Aug-16	15	Pre-Hr 1	91	0.201	0.076	Yes	2.14	2.14	1.94
3	**4-Aug-16**	**16**	**Event Hr 1**	**90**	**-0.85**	**0.07**	**Yes**	**1.24**	**1.24**	**2.09**
3	**4-Aug-16**	**17**	**Event Hr 2**	**87**	**-0.84**	**0.07**	**Yes**	**1.64**	**1.64**	**2.49**
3	**4-Aug-16**	**18**	**Event Hr 3**	**83**	**-0.65**	**0.07**	**Yes**	**1.94**	**1.95**	**2.60**
3	4-Aug-16	19	Post-Hr 1	78	0.333	0.073	Yes	2.82	2.82	2.49
3	4-Aug-16	20	Post-Hr 2	75	0.228	0.068	Yes	2.59	2.59	2.36
3	4-Aug-16	21	Post-Hr 3	71	0.132	0.069	Yes	2.38	2.37	2.24
3	4-Aug-16	22	Post-Hr 4	69	0.077	0.059	No	2.03	2.02	1.94
3	4-Aug-16	23	Post-Hr 5	67	0.052	0.052	No	1.62	1.61	1.55
3	4-Aug-16	0	Post-Hr 6	64	0.000	0.042	No	0.92	1.02	1.02
3	5-Aug-16	1	Post-Hr 7	63	0.030	0.036	No	0.98	0.98	0.95
3	5-Aug-16	2	Post-Hr 8	61	0.019	0.029	No	0.83	0.83	0.81
4	11-Aug-16	15	Pre-Hr 1	89	0.209	0.068	Yes	1.93	1.93	1.72
4	**11-Aug-16**	**16**	**Event Hr 1**	**89**	**-0.70**	**0.06**	**Yes**	**1.16**	**1.16**	**1.86**
4	**11-Aug-16**	**17**	**Event Hr 2**	**88**	**-0.62**	**0.07**	**Yes**	**1.53**	**1.53**	**2.15**
4	**11-Aug-16**	**18**	**Event Hr 3**	**84**	**-0.52**	**0.07**	**Yes**	**1.81**	**1.82**	**2.33**
4	11-Aug-16	19	Post-Hr 1	78	0.443	0.072	Yes	2.82	2.82	2.38
4	11-Aug-16	20	Post-Hr 2	75	0.331	0.067	Yes	2.61	2.61	2.28
4	11-Aug-16	21	Post-Hr 3	73	0.303	0.064	Yes	2.45	2.45	2.14
4	11-Aug-16	22	Post-Hr 4	71	0.197	0.058	Yes	2.11	2.11	1.91
4	11-Aug-16	23	Post-Hr 5	68	0.005	0.050	No	1.60	1.60	1.59
4	12-Aug-16	0	Post-Hr 6	67	-0.031	0.045	No	1.23	1.23	1.26
4	12-Aug-16	1	Post-Hr 7	66	0.010	0.038	No	1.03	1.03	1.02
4	12-Aug-16	2	Post-Hr 8	63	0.041	0.031	No	0.88	0.89	0.84
5	12-Aug-16	15	Pre-Hr 1	96	0.365	0.085	Yes	2.73	2.74	2.37
5	**12-Aug-16**	**16**	**Event Hr 1**	**97**	**-0.97**	**0.08**	**Yes**	**1.57**	**1.57**	**2.54**
5	**12-Aug-16**	**17**	**Event Hr 2**	**94**	**-0.79**	**0.08**	**Yes**	**2.10**	**2.10**	**2.90**
5	**12-Aug-16**	**18**	**Event Hr 3**	**89**	**-0.59**	**0.08**	**Yes**	**2.38**	**2.38**	**2.97**
5	12-Aug-16	19	Post-Hr 1	83	0.416	0.082	Yes	3.18	3.18	2.76
5	12-Aug-16	20	Post-Hr 2	81	0.266	0.083	Yes	2.99	2.99	2.72
5	12-Aug-16	21	Post-Hr 3	79	0.159	0.083	Yes	2.84	2.84	2.68

Event	Date	Hour	Hour Type	Outside Temp. (^{o}F)	Estimated Impact (kW)	SE Estimated Impact (kW)	Significant at 10%	Metered (kW)	Predicted (kW)	Baseline (kW)
5	12-Aug-16	22	Post-Hr 4	75	0.053	0.082	No	2.60	2.60	2.54
5	12-Aug-16	23	Post-Hr 5	72	0.069	0.079	No	2.13	2.13	2.06
5	13-Aug-16	0	Post-Hr 6	69	0.043	0.071	No	1.70	1.70	1.65
5	13-Aug-16	1	Post-Hr 7	68	0.088	0.049	Yes	1.34	1.34	1.25
5	13-Aug-16	2	Post-Hr 8	66	0.105	0.040	Yes	1.17	1.17	1.06
6	18-Aug-16	15	Pre-Hr 1	100	0.145	0.085	Yes	2.60	2.61	2.46
6	**18-Aug-16**	**16**	**Event Hr 1**	**98**	**-1.16**	**0.08**	**Yes**	**1.55**	**1.55**	**2.71**
6	**18-Aug-16**	**17**	**Event Hr 2**	**94**	**-0.91**	**0.08**	**Yes**	**2.14**	**2.14**	**3.05**
6	**18-Aug-16**	**18**	**Event Hr 3**	**89**	**-0.70**	**0.08**	**Yes**	**2.49**	**2.49**	**3.19**
6	18-Aug-16	19	Post-Hr 1	85	0.163	0.080	Yes	3.38	3.38	3.22
6	18-Aug-16	20	Post-Hr 2	82	0.203	0.080	Yes	3.29	3.29	3.08
6	18-Aug-16	21	Post-Hr 3	79	0.168	0.076	Yes	3.10	3.10	2.94
6	18-Aug-16	22	Post-Hr 4	75	0.026	0.071	No	2.67	2.67	2.65
6	18-Aug-16	23	Post-Hr 5	71	0.073	0.062	No	2.13	2.13	2.06
6	19-Aug-16	0	Post-Hr 6	71	0.066	0.055	No	1.67	1.66	1.60
6	19-Aug-16	1	Post-Hr 7	68	0.127	0.041	Yes	1.34	1.34	1.21
6	19-Aug-16	2	Post-Hr 8	66	0.044	0.037	No	1.14	1.14	1.09
7	19-Aug-16	15	Pre-Hr 1	99	0.149	0.085	Yes	3.04	3.04	2.89
7	**19-Aug-16**	**16**	**Event Hr 1**	**98**	**-1.23**	**0.08**	**Yes**	**1.74**	**1.75**	**2.98**
7	**19-Aug-16**	**17**	**Event Hr 2**	**96**	**-0.82**	**0.08**	**Yes**	**2.35**	**2.36**	**3.18**
7	**19-Aug-16**	**18**	**Event Hr 3**	**91**	**-0.62**	**0.08**	**Yes**	**2.56**	**2.57**	**3.19**
7	19-Aug-16	19	Post-Hr 1	84	0.350	0.078	Yes	3.37	3.38	3.03
7	19-Aug-16	20	Post-Hr 2	80	0.198	0.078	Yes	3.17	3.18	2.98
7	19-Aug-16	21	Post-Hr 3	76	0.114	0.071	No	2.96	2.96	2.85
7	19-Aug-16	22	Post-Hr 4	74	0.061	0.069	No	2.62	2.61	2.55
7	19-Aug-16	23	Post-Hr 5	72	0.047	0.065	No	2.17	2.16	2.11
7	20-Aug-16	0	Post-Hr 6	69	0.052	0.057	No	1.76	1.75	1.70
7	20-Aug-16	1	Post-Hr 7	67	0.054	0.048	No	1.41	1.40	1.35
7	20-Aug-16	2	Post-Hr 8	67	0.059	0.046	No	1.22	1.22	1.16
8	25-Aug-16	15	Pre-Hr 1	94	0.278	0.078	Yes	2.58	2.59	2.31
8	**25-Aug-16**	**16**	**Event Hr 1**	**93**	**-1.03**	**0.07**	**Yes**	**1.48**	**1.48**	**2.51**
8	**25-Aug-16**	**17**	**Event Hr 2**	**92**	**-0.71**	**0.08**	**Yes**	**2.01**	**2.02**	**2.73**
8	**25-Aug-16**	**18**	**Event Hr 3**	**87**	**-0.59**	**0.07**	**Yes**	**2.29**	**2.31**	**2.90**
8	25-Aug-16	19	Post-Hr 1	81	0.432	0.073	Yes	3.24	3.26	2.83
8	25-Aug-16	20	Post-Hr 2	77	0.297	0.075	Yes	3.04	3.05	2.75
8	25-Aug-16	21	Post-Hr 3	76	0.149	0.072	Yes	2.82	2.83	2.68
8	25-Aug-16	22	Post-Hr 4	73	0.030	0.067	No	2.39	2.39	2.36
8	25-Aug-16	23	Post-Hr 5	69	0.084	0.053	No	1.93	1.93	1.84
8	26-Aug-16	0	Post-Hr 6	67	0.029	0.046	No	1.47	1.47	1.44

Event	Date	Hour	Hour Type	Outside Temp. (°F)	Estimated Impact (kW)	SE Estimated Impact (kW)	Significant at 10%	Metered (kW)	Predicted (kW)	Baseline (kW)
8	26-Aug-16	1	Post-Hr 7	64	0.066	0.037	Yes	1.20	1.20	1.13
8	26-Aug-16	2	Post-Hr 8	62	0.054	0.029	Yes	0.97	0.97	0.92
9	26-Aug-16	14	Pre-Hr 1	95	0.347	0.080	Yes	2.59	2.59	2.25
9	**26-Aug-16**	**15**	**Event Hr 1**	**95**	**-0.97**	**0.08**	**Yes**	**1.39**	**1.40**	**2.37**
9	**26-Aug-16**	**16**	**Event Hr 2**	**95**	**-0.77**	**0.08**	**Yes**	**1.82**	**1.82**	**2.60**
9	**26-Aug-16**	**17**	**Event Hr 3**	**93**	**-0.66**	**0.08**	**Yes**	**2.17**	**2.18**	**2.84**
9	26-Aug-16	18	Post-Hr 1	86	0.344	0.076	Yes	3.25	3.26	2.91
9	26-Aug-16	19	Post-Hr 2	81	0.294	0.076	Yes	2.97	2.97	2.68
9	26-Aug-16	20	Post-Hr 3	79	0.335	0.075	Yes	2.84	2.84	2.50
9	26-Aug-16	21	Post-Hr 4	77	0.262	0.075	Yes	2.64	2.64	2.38
9	26-Aug-16	22	Post-Hr 5	73	0.166	0.065	Yes	2.26	2.26	2.09
9	26-Aug-16	23	Post-Hr 6	69	0.126	0.055	Yes	1.85	1.86	1.73
9	27-Aug-16	0	Post-Hr 7	66	0.119	0.046	Yes	1.46	1.47	1.35
9	27-Aug-16	1	Post-Hr 8	63	0.034	0.041	No	1.17	1.17	1.13

Table 7 provides additional model details regarding hourly demand impacts during winter event days. As noted, more extreme weather days (events 2 and 3) saw larger demand reductions in the first hours (over 1 kW), which then decreased significantly in the subsequent hours.

Table 7. Winter Hourly Impacts by Event

Event	Date	Hour	Hour Type	Outside Temp. (°F)	Estimated Impact (kW)	SE Estimated Impact (kW)	Significant at 10%	Metered (kW)	Predicted (kW)	Baseline (kW)
1	29-Dec-15	15	Pre-Hr 1	39	0.713	0.355	Yes	3.07	3.09	2.38
1	**29-Dec-15**	**16**	**Event Hr 1**	**39**	**-0.62**	**0.32**	**Yes**	**2.18**	**2.12**	**2.74**
1	**29-Dec-15**	**17**	**Event Hr 2**	**38**	**-0.62**	**0.36**	**Yes**	**2.33**	**2.34**	**2.95**
1	**29-Dec-15**	**18**	**Event Hr 3**	**38**	**-0.76**	**0.38**	**Yes**	**2.42**	**2.43**	**3.19**
1	29-Dec-15	19	Post-Hr 1	38	0.977	0.411	Yes	3.68	3.71	2.73
1	29-Dec-15	20	Post-Hr 2	38	0.349	0.394	No	3.03	3.07	2.72
1	29-Dec-15	21	Post-Hr 3	37	0.243	0.314	No	2.36	2.38	2.14
1	29-Dec-15	22	Post-Hr 4	36	0.327	0.307	No	2.27	2.21	1.88
1	29-Dec-15	23	Post-Hr 5	34	0.430	0.402	No	2.33	2.33	1.90
1	30-Dec-15	0	Post-Hr 6	33	0.206	0.294	No	1.94	1.94	1.74
1	30-Dec-15	1	Post-Hr 7	32	0.311	0.309	No	1.98	1.98	1.67
1	30-Dec-15	2	Post-Hr 8	32	0.478	0.330	No	2.23	2.23	1.76
2	30-Dec-15	15	Pre-Hr 1	40	-0.065	0.485	No	2.65	2.69	2.76
2	**30-Dec-15**	**16**	**Event Hr 1**	**38**	**-1.26**	**0.29**	**Yes**	**1.64**	**1.66**	**2.92**
2	**30-Dec-15**	**17**	**Event Hr 2**	**36**	**-0.89**	**0.44**	**Yes**	**2.55**	**2.58**	**3.47**

Event	Date	Hour	Hour Type	Outside Temp. (°F)	Estimated Impact (kW)	SE Estimated Impact (kW)	Significant at 10%	Metered (kW)	Predicted (kW)	Baseline (kW)
2	**30-Dec-15**	**18**	**Event Hr 3**	**35**	**-0.19**	**0.44**	**No**	**2.84**	**2.88**	**3.06**
2	30-Dec-15	19	Post-Hr 1	35	0.335	0.518	No	3.53	3.58	3.24
2	30-Dec-15	20	Post-Hr 2	35	0.300	0.499	No	3.56	3.56	3.26
2	30-Dec-15	21	Post-Hr 3	35	0.157	0.366	No	2.97	2.97	2.82
2	30-Dec-15	22	Post-Hr 4	34	0.621	0.399	No	2.82	2.86	2.24
2	30-Dec-15	23	Post-Hr 5	34	-0.308	0.392	No	2.14	2.16	2.46
2	31-Dec-15	0	Post-Hr 6	34	-0.196	0.342	No	1.99	1.98	2.18
2	31-Dec-15	1	Post-Hr 7	33	0.508	0.353	No	2.39	2.40	1.89
2	31-Dec-15	2	Post-Hr 8	33	0.184	0.362	No	2.39	2.40	2.21
3	4-Jan-16	15	Pre-Hr 1	35	0.862	0.492	Yes	3.94	4.00	3.14
3	**4-Jan-16**	**16**	**Event Hr 1**	**34**	**-1.55**	**0.35**	**Yes**	**1.90**	**1.92**	**3.47**
3	**4-Jan-16**	**17**	**Event Hr 2**	**34**	**-0.84**	**0.41**	**Yes**	**2.73**	**2.75**	**3.59**
3	**4-Jan-16**	**18**	**Event Hr 3**	**34**	**-0.50**	**0.42**	**No**	**2.99**	**2.98**	**3.48**
3	4-Jan-16	19	Post-Hr 1	33	0.790	0.513	No	4.41	4.45	3.66
3	4-Jan-16	20	Post-Hr 2	33	-0.076	0.415	No	3.11	3.15	3.23
3	4-Jan-16	21	Post-Hr 3	33	-0.532	0.319	Yes	2.28	2.28	2.81
3	4-Jan-16	22	Post-Hr 4	32	-0.418	0.334	No	2.08	1.95	2.37
3	4-Jan-16	23	Post-Hr 5	32	-0.453	0.241	Yes	1.51	1.46	1.92
3	5-Jan-16	0	Post-Hr 6	33	-0.130	0.280	No	1.58	1.60	1.73
3	5-Jan-16	1	Post-Hr 7	33	0.099	0.308	No	1.71	1.73	1.63
3	5-Jan-16	2	Post-Hr 8	33	0.180	0.307	No	2.23	2.25	2.07
4	6-Jan-16	15	Pre-Hr 1	41	1.166	0.483	Yes	3.46	3.48	2.31
4	**6-Jan-16**	**16**	**Event Hr 1**	**39**	**-0.37**	**0.30**	**No**	**2.26**	**2.25**	**2.61**
4	**6-Jan-16**	**17**	**Event Hr 2**	**39**	**-0.22**	**0.32**	**No**	**2.63**	**2.63**	**2.85**
4	**6-Jan-16**	**18**	**Event Hr 3**	**38**	**-0.66**	**0.38**	**Yes**	**2.79**	**2.82**	**3.48**
4	6-Jan-16	19	Post-Hr 1	38	1.256	0.493	Yes	4.23	4.23	2.97
4	6-Jan-16	20	Post-Hr 2	38	0.248	0.390	No	3.19	3.23	2.99
4	6-Jan-16	21	Post-Hr 3	38	0.300	0.381	No	2.95	2.97	2.67
4	6-Jan-16	22	Post-Hr 4	37	-0.248	0.361	No	2.03	2.02	2.27
4	6-Jan-16	23	Post-Hr 5	37	-0.030	0.287	No	1.67	1.66	1.69
4	7-Jan-16	0	Post-Hr 6	35	-0.088	0.264	No	1.56	1.56	1.64
4	7-Jan-16	1	Post-Hr 7	36	0.403	0.287	No	1.94	1.95	1.54
4	7-Jan-16	2	Post-Hr 8	36	0.171	0.261	No	1.93	1.93	1.76
5	1-Feb-16	15	Pre-Hr 1	45	0.966	0.472	Yes	3.16	3.20	2.24
5	**1-Feb-16**	**16**	**Event Hr 1**	**45**	**-0.86**	**0.38**	**Yes**	**1.81**	**1.81**	**2.68**
5	**1-Feb-16**	**17**	**Event Hr 2**	**44**	**-0.20**	**0.33**	**No**	**2.33**	**2.34**	**2.53**
5	**1-Feb-16**	**18**	**Event Hr 3**	**43**	**0.01**	**0.33**	**No**	**2.43**	**2.43**	**2.42**
5	1-Feb-16	19	Post-Hr 1	42	0.985	0.398	Yes	3.65	3.69	2.70
5	1-Feb-16	20	Post-Hr 2	42	-0.023	0.340	No	2.67	2.70	2.72

Event	Date	Hour	Hour Type	Outside Temp. (°F)	Estimated Impact (kW)	SE Estimated Impact (kW)	Significant at 10%	Metered (kW)	Predicted (kW)	Baseline (kW)
5	1-Feb-16	21	Post-Hr 3	41	-0.100	0.277	No	2.34	2.33	2.43
5	1-Feb-16	22	Post-Hr 4	41	-0.169	0.257	No	1.78	1.79	1.96
5	1-Feb-16	23	Post-Hr 5	40	-0.136	0.299	No	1.56	1.58	1.72
5	2-Feb-16	0	Post-Hr 6	38	0.161	0.217	No	1.47	1.50	1.34
5	2-Feb-16	1	Post-Hr 7	37	0.037	0.243	No	1.45	1.46	1.42
5	2-Feb-16	2	Post-Hr 8	36	-0.213	0.230	No	1.48	1.50	1.72
6	9-Feb-16	6	Pre-Hr 1	40	0.449	0.368	No	2.98	3.02	2.57
6	**9-Feb-16**	**7**	**Event Hr 1**	**40**	**-0.65**	**0.29**	**Yes**	**1.86**	**1.88**	**2.53**
6	**9-Feb-16**	**8**	**Event Hr 2**	**45**	**-0.29**	**0.26**	**No**	**1.82**	**1.82**	**2.12**
6	**9-Feb-16**	**9**	**Event Hr 3**	**51**	**-0.13**	**0.26**	**No**	**1.53**	**1.53**	**1.66**
6	9-Feb-16	10	Post-Hr 1	55	0.588	0.271	Yes	2.08	2.08	1.49
6	9-Feb-16	11	Post-Hr 2	57	0.287	0.202	No	1.45	1.45	1.16
6	9-Feb-16	12	Post-Hr 3	58	0.395	0.188	Yes	1.47	1.48	1.09
6	9-Feb-16	13	Post-Hr 4	59	0.311	0.206	No	1.37	1.39	1.08
6	9-Feb-16	14	Post-Hr 5	60	0.130	0.179	No	1.26	1.26	1.13
6	9-Feb-16	15	Post-Hr 6	58	0.104	0.190	No	1.49	1.49	1.39
6	9-Feb-16	16	Post-Hr 7	57	0.084	0.243	No	1.67	1.68	1.60
6	9-Feb-16	17	Post-Hr 8	54	0.267	0.223	No	2.00	2.02	1.75
7	17-Feb-16	16	Pre-Hr 1	53	0.297	0.247	No	2.18	2.19	1.89
7	**17-Feb-16**	**17**	**Event Hr 1**	**52**	**-0.44**	**0.21**	**Yes**	**1.63**	**1.64**	**2.09**
7	**17-Feb-16**	**18**	**Event Hr 2**	**49**	**-0.54**	**0.24**	**Yes**	**1.83**	**1.84**	**2.38**
7	**17-Feb-16**	**19**	**Event Hr 3**	**48**	**-0.48**	**0.25**	**Yes**	**1.88**	**1.89**	**2.37**
7	17-Feb-16	20	Post-Hr 1	48	-0.089	0.283	No	2.49	2.51	2.60
7	17-Feb-16	21	Post-Hr 2	47	-0.203	0.220	No	1.87	1.89	2.09
7	17-Feb-16	22	Post-Hr 3	47	-0.065	0.183	No	1.49	1.49	1.56
7	17-Feb-16	23	Post-Hr 4	46	-0.028	0.142	No	1.19	1.17	1.20
7	18-Feb-16	0	Post-Hr 5	45	-0.193	0.145	No	0.98	0.99	1.18
7	18-Feb-16	1	Post-Hr 6	44	0.124	0.136	No	1.03	1.03	0.90
7	18-Feb-16	2	Post-Hr 7	44	-0.110	0.150	No	1.08	1.09	1.20
7	18-Feb-16	3	Post-Hr 8	45	0.127	0.152	No	1.41	1.44	1.31
8	26-Feb-16	16	Pre-Hr 1	51	0.387	0.319	No	2.44	2.46	2.08
8	**26-Feb-16**	**17**	**Event Hr 1**	**50**	**-0.44**	**0.20**	**Yes**	**1.61**	**1.62**	**2.07**
8	**26-Feb-16**	**18**	**Event Hr 2**	**50**	**-0.88**	**0.28**	**Yes**	**1.47**	**1.48**	**2.36**
8	**26-Feb-16**	**19**	**Event Hr 3**	**50**	**-0.64**	**0.24**	**Yes**	**1.53**	**1.53**	**2.17**
8	26-Feb-16	20	Post-Hr 1	50	0.156	0.248	No	2.26	2.25	2.10
8	26-Feb-16	21	Post-Hr 2	49	-0.310	0.187	Yes	1.48	1.49	1.80
8	26-Feb-16	22	Post-Hr 3	50	-0.070	0.159	No	1.32	1.33	1.39
8	26-Feb-16	23	Post-Hr 4	50	-0.053	0.135	No	0.99	1.00	1.05
8	27-Feb-16	0	Post-Hr 5	50	-0.060	0.138	No	0.94	0.94	1.00

Event	Date	Hour	Hour Type	Outside Temp. (°F)	Estimated Impact (kW)	SE Estimated Impact (kW)	Significant at 10%	Metered (kW)	Predicted (kW)	Baseline (kW)
8	27-Feb-16	1	Post-Hr 6	52	0.063	0.153	No	0.92	0.94	0.88
8	27-Feb-16	2	Post-Hr 7	52	0.093	0.150	No	0.93	0.93	0.83
8	27-Feb-16	3	Post-Hr 8	52	-0.065	0.143	No	0.92	0.93	0.99

Certificate of Service

I hereby certify that I have this day caused the foregoing **Notice of Application for Reauthorization of Deferral of Expenses Associated with Two Residential Demand Response Pilots** to be served by electronic mail to those parties whose e-mail addresses appear on the attached service list for OPUC Dockets No. UM 1708 and UE 319.

Dated at Portland, Oregon, this 2nd day of June 2017.

for

Stefan Brown, Manager
Regulatory Affairs
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