Exhibit CV-3

Part 2 of 2

ELECTRIC POWER RESEARCH INSTITUTE

FirstEnergy's Smart Grid Investment Grant Consumer Behavior Study

Phase 1—Final Evaluation

2015 TECHNICAL REPORT

FirstEnergy's Smart Grid Investment Grant Consumer Behavior Study

Phase 1—Final Evaluation

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Abstract

FirstEnergy has undertaken a three-year consumer behavior study (CBS) to evaluate residential customer response to alternative inducements (experimental treatments) to alter their electricity usage during the afternoon hours of hot summer days. Work was performed under funding from a federal Smart Grid Investment Grant (SGIG). The focal point of the study was to quantify how residential customers respond to a monetary inducement, such as peak time rebate (PTR), to reduce load during pre-specified hours (events) with a day's advance notice.

In addition, the study evaluated the impacts of two enabling technologies on customer response: the in-home display (IHD) and programmable controllable thermostat (PCT). Only customers identified as having central air conditioning were eligible to receive a PCT. The customers without central air were eligible to receive an IHD.

This report describes the findings of impact analyses conducted for the entire study period (2012-2014) and discusses their implications for the design and implementation of similar programs by FirstEnergy and others. Also covered are study experimental design and a comparison of study participation, weather, and loads across the years. The report fulfills FirstEnergy's obligation under the SGIG grant and serves to inform the larger community of program designers and evaluators of the methods employed and the findings.

Keywords
Peak time rebate (PTR)
Consumer behavior study (CBS)
Programmable controllable thermostat (PCT)
In-home display (IHD)
Smart Grid Investment Grant (SGIG)
Demand response programs

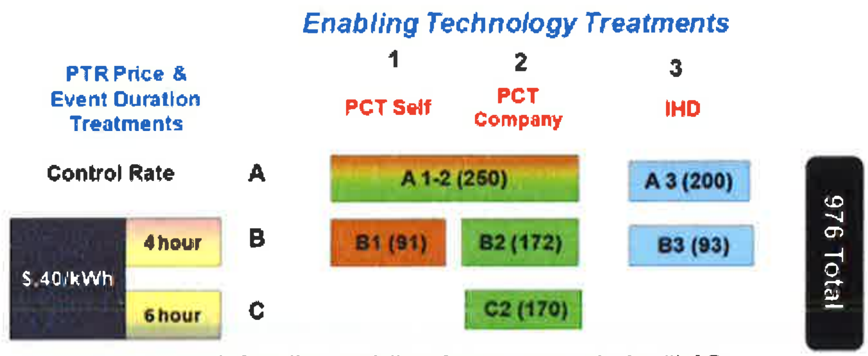
Executive Summary

With funding from a federal Smart Grid Investment Grant (SGIG), FirstEnergy designed a consumer behavior study (CBS) to inform the development of demand response programs. The goal of these programs is to decrease the state of Ohio's system peak demand and achieve other aims, including reduced electricity usage at times when supply prices are high or system reliability is in jeopardy. The focal point was to quantify how residential customers respond to a monetary inducement such as peak time rebate (PTR) to reduce load during pre-specified hours (events) with a day's advance notice.

In addition, the study evaluated the impacts of two enabling technologies on customer response: the in-home display (IHD) and programmable controllable thermostat (PCT). Only customers identified as having central air conditioning were eligible to receive a PCT. The customers without central air were eligible to receive an IHD.

Two novel aspects were included to resolve important ambiguities about how customers respond to PTR-type incentives. First, at the beginning of events (hot summer days) FirstEnergy sent a signal to PCTs for two of the treatment groups that raised participants' thermostat settings by three degrees. The third PCT treatment group was notified of the PTR event, but it was each participant's choice whether to make a PCT adjustment. Second, customers in the utility-initiated PCT adjustment treatment were further partitioned in terms of the event duration, four or six hours. All treatment customers had the ability to opt-out of any PTR event, either by failing to respond or by pushing an override button in the case of utility-controlled PCTs, but relatively few elected to do so.

Figure ES-1 below portrays the experimental design. Control groups were filled by random assignment. The treatment groups were populated through recruitment. Offers were extended to eligible customers, separately for the PCT and IHD experiments, until the desired number of subjects was achieved or the customer pool was exhausted. Customers making PCT adjustments themselves were assigned to the 4-hour treatments. Those that elected utility-initiated PCT adjustments were randomly assigned to the 4-hour or 6-hour event duration treatment. All customers in the combined IHD and PTR treatments were exposed to 4-hour events.



- **A 1/2** drawn randomly from the population of survey respondents with AC
- **B1 and B2/C2** recruited randomly from the population of survey respondents with AC, given a choice of self-controlled or FirstEnergy-controlled PCT
- **B2/C2** were recruited to the PCT Company treatments and then randomly assigned to the 4-hour and 6-hour treatments
- **A3** drawn from the population without central AC, **B3** recruited randomly from that population

Figure ES-1
FirstEnergy Consumer Behavior Study Phase 1 Experimental Design

Recruitment occurred in the fall of 2011 and winter of 2012, after which the technology was deployed. PTR events (up to 15) were called from June 1 to August 31 in 2012, 2013, and 2014.

FirstEnergy commissioned EPRI to conduct a preliminary CBS analysis using hourly metered data for June–August 2012 from 976 customers in the pilot (control and treatment groups) as well as demographic and premise data from a survey administered in the fall of 2012. FirstEnergy commissioned EPRI to complete the final analysis of 2013 and 2014 pilot data following the summer of 2014.

EPRI conducted a series of analyses initially involving graphic depictions of customer usage by treatment, followed by application of structured models (fixed effects and electricity demand) to quantify the customer demand response associated with each treatment.

During the summer of 2012, PTR resulted in substantial usage reductions during events (15 were called) for customers who allowed the company to control the PCT during events. The reduction was considerably lower, but still statistically significant for customers who managed the PCT themselves during events. The average hourly reduction was approximately the same for the 4-hour and 6-hour utility-controlled PCT treatment groups. The group that received an IHD and was offered PTR payments exhibited a load reduction similar to that of the self-managed PCT group.

Usage reductions during the summers of 2013 and 2014 were also substantial and statistically significant for customers who allowed utility control of the PCT. The other groups (customer controlled PCT and IHD), however, had mixed results over the study period and seemed to demonstrate fatigue when events were called. The summers of 2013 and 2014 were also milder than 2012. In 2013 there were 12 events called, while only six events were called in 2014.

This report fulfills FirstEnergy's obligation under the SGIG grant and serves to inform the larger community of program designers and evaluators of the methods employed and the findings.

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Section 1: Study Overview

Introduction

This report summarizes the results of a three-year study undertaken by FirstEnergy to evaluate residential customer response to alternative inducements (experimental treatments) to alter their electricity usage during the afternoon hours of hot summer days. Its provenance was the confluence of interest by FirstEnergy and the Public Utilities Commission of Ohio (PUCO) to understand better the role of load as a dispatchable resource, and Federal Smart Grid Investment Grant (SGIG) funds available through the American Recovery & Reinvestment Act of 2009. FirstEnergy's application for funding under this grant was filed in October of 2009. FirstEnergy filed an application with PUCO to approve recovery of the funds to match the grant, which issued its approval thereof June 2010, encouraging FirstEnergy to work with the Department of Energy (DOE) to develop a Consumer Behavior Study (CBS).

FirstEnergy worked closely with the Technical Advisory Group (TAG) assigned to the project by the DOE to develop the design of its CBS. EPRI supported FirstEnergy in the development of the Phase 1 design and conducted analyses for all three years of the study. Preliminary results (2012) were previously published.[1,2] EPRI applied similar impact analysis to summer 2013 and 2014 hourly usage data from treatment and control customers. The combined set of results were used to produce this consolidated CBS Phase load impact study.

Report Contents

This report describes the findings of impact analyses conducted for the entire study period (2012-2014) and discusses their implications for the design and implementation of similar programs by FirstEnergy and others. It fulfills FirstEnergy's obligation under the SGIG grant and serves to inform the larger community of program designers and evaluators of the methods employed and the findings.

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[1] *FirstEnergy's Consumer Behavior Study: Preliminary Evaluation for the Summer 2012.* EPRI, Palo Alto, CA. 2013. 3002001870.

[2] FirstEnergy implemented a Phase 2 study, which is not part of the SGIG project, informed by the results of the 2012 Phase 1 analysis.

Section 2 describes the study experimental design. Section 3 compares study participation, weather and loads across the study years. Section 4 describes the impact analyses conducted and the results. Section 5 summarizes the findings and their implications.

Section 2: CBS Experimental Design

Introduction

This section describes the CBS study design, the pricing and technology employed, and the recruitment by FirstEnergy of residential customers as participants, as a treatment or a control.

FirstEnergy directed the CBS study to residential customers in a geographic area served by its Illuminating Company that was also the site of several other Smart Grid research projects conducted under the auspices of the DOE SGIG. Focusing the study on a defined geographic region accommodated the installation of Advanced Metering Infrastructure (AMI) to provide the metering and communication system needed to implement the CBS design.

A 34-circuit area located in the Illuminating Company's service territory east of the city of Cleveland, Ohio was chosen for the study. An initial population of 15,000 customers on contiguous circuits in a subset of the SGIG study area were asked to complete a qualifying survey. Its purposes was to identify what appliances they had in their homes, and provide information on premise characteristics and demographic information. Importantly, it distinguished homes with central air conditioning (CAC) that would be eligible to receive a programmable communicating thermostat (PCT) from those without central AC that would be eligible for an In-home Display (IHD). Both were eligible to participate in FirstEnergy's PTR program. The result was that two experiments were undertaken with different populations, each requiring a control group.

Experimental Treatments

The purpose of the study was to quantify residential customer response to peak time rebate (PTR) pricing. PTR provides a load serving entity (LSE) with an option to modify the tariff terms of electric service under specific conditions as defined under the standard tariff.[3] When the LSE anticipates that there may be a supply shortage the next day, it sends an event notice to participants offering to pay for load reductions undertaken during the declared event hours.

[3] EPRI. 2011. A System for Understanding Retail Electric Rate Structures (EPRI 1021962).

FirstEnergy CBS participants received a smart meter capable of two-way communication. Customers with CAC were provided a PCT. Participants that did not have CAC were provided an IHD that shows their instantaneous usage.

The PCTs were deployed in two ways. Participants could elect to have FirstEnergy automatically increase the PCT setting three (3) degrees from its current setting when an event commenced (utility-control). Alternatively, FirstEnergy would notify the participants of the event and each participant was responsible for making a PCT adjustment (customer control). Those in the latter group were encouraged to raise the setting three degrees when an event commenced, but that would not result without an affirmative action by the participants, either when an event commenced (perhaps prompted by the flashing blue light), or beforehand as a result of the day-ahead notice of an event.

The PCT is an Energate thermostat (the device on the right below) that has two-way communication through the meter's Zigbee communication network. The thermostat is capable of displaying messages and has a blue light that indicates that an event has been triggered. The PCT also has an override feature, which enables customers with PCTs under utility-control to opt-out of an event. At the time of installation, the contractor programmed the PCT (utility control) or showed the customer how to program the PCT (customer control) as well as how to override an event. In addition, they were provided with a call-in number to opt out of events in case they encountered difficulty with the PCT override feature.

The IHD (shown on the left below) provides real-time information regarding the customer's usage. It is a portable device that communicates with the smart meter through a Zigbee communication network to a device, located within the premise, that displays the customer's kW usage at any point in time. The device is also capable of displaying messages regarding PTR events.

An additional CBS treatment distinction was based on the PTR event duration, which was either four (2:00 p.m. – 6:00 p.m.) or six hours (1:00 p.m. – 7:00 p.m.) that was randomly assigned to utility-controlled PCT treatment customers, as discussed below.

Baseline for Peak Time Rebate

Treatment customers (those with PCTs or an IHD) were offered an inducement to reduce electricity usage during periods (events) when the system peak demand was forecasted to be high. PTR is a mechanism for adjusting conventional rates, which are not time-differentiated, so that at times specified by FirstEnergy customers have incentives that reflect the elevated cost of supplying electricity. Events were declared the day prior by FirstEnergy based on forecasted weather and loads. Treatment customers were paid $0.40/kWh for load reductions undertaken during events.

The PTR payment to treatment customers was calculated by comparing the customer's usage during the event period to its average usage (in the same period) on the five prior non-event, non-holiday weekdays (called the baseline usage). In addition, an upward adjustment to the baseline was made if the customer used more electricity in the two hours prior to the event. This adjustment was to discourage customers from pre-cooling so that not only would event period demand reduction be achieved, but customers would be encouraged to reduce their overall event-day usage as well. The prior period adjustment was calculated using the following method:

$$Baseline = \begin{cases} \sum_{i=1}^{t}\left(AvgEvt_i - \left(\frac{(d1+d2)}{2}\right)\right) & if \quad \frac{(d1+d2)}{2} > 0 \\ \sum_{i=1}^{t} AvgEvt_i & Otherwise \end{cases}$$

Where:

t = 4 or 6 hours 2:00 to 6:00 p.m. or 1:00 to 7:00 p.m.;

$AvgEvt_i$ = Average usage for hour i for the five previous non-event and non-holiday weekdays;

d2 = Event day usage two hours prior to the event window minus the average usage of that hour the previous five non-event, non-holiday weekdays;

d1 = Event day usage one hour prior to the event window minus the average usage that hour on previous five days non-event non-holiday weekdays; and

The average of *d2* and *d1* is subtracted from each hour's usage to get the adjusted baseline.

Day-Ahead Notification

Customers were notified the day before that a PTR event would be in force the next day. Events were always declared for a pre-established event window, either four or six consecutive hours starting at a pre-specified time. Notification was made through the automated meter's Zigbee communication device to the PCT or IHD, as well as through two other methods of the customer's choosing; the options were voicemail, e-mail, and text message.

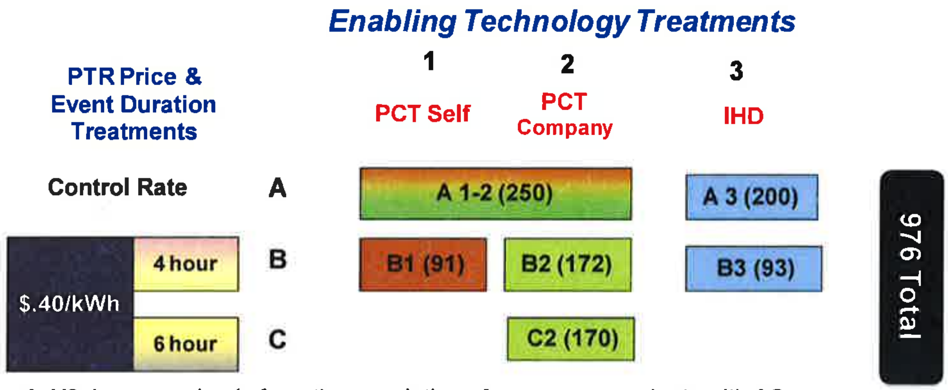
CBS Experimental Design

FirstEnergy employed a structured experimental design to isolate the effects of PTR monetary inducements and PCT and IHD technologies from other factors that influence household electricity demand. Control customers were selected randomly from the sampling frame. Customers were selected randomly by FirstEnergy to be treatment candidates from the remaining sample frame and offered the opportunity to participate in that treatment. Those that accepted the offer to participate were enrolled in the pilot. Those that did not were removed from consideration in any other treatment.

The study design called for testing the impacts of PCTs that control central air conditioners. Hence, eligible customers were sorted by those that had a central air conditioner and those that did not. The former were eligible to participate in the PCT treatments, and the latter in the IHD treatments. The result of this partition is that the study involved two separate technology treatment experiments; one to test PCT effects and another to test IHD effects. A separate control group, comprised of the customers that are eligible for the treatment, was drawn for each experiment. In both cases, the technology was coupled with the PTR inducement to reduce event electricity usage.

Figure 2-1 portrays the CBS experimental design. The cells (elements of the design) are depicted as colored boxes labeled alphanumerically that correspond to control cells (A 1-2 and A3) and treatment cells (B1, B2, B3, and C2) that have a common rate treatment (PTR payment of $0.40/kWh) for either a 4-hour or 6-hour event duration combined with an enabling technology treatment (PCT or IHD).[4] The values in parentheses in the cells are the number of participants that were recruited (or randomly drawn, in the case of the control groups) into that treatment cell.

[4] Figure 2-1 displays the experimental design as constructed. The 6-hour PTR event was only implemented for utility-control PCT participants due to the limited number of qualified residence with CAC (4,429).



•**A 1/2** drawn randomly from the population of survey respondents with AC

•**B1 and B2/C2** recruited randomly from the population of survey respondents with AC, given a choice of self-controlled or FirstEnergy-controlled PCT

•**B2/C2** were recruited to the PCT Company treatments and then randomly assigned to the 4-hour and 6-hour treatments

•**A3 drawn** from the population without central AC, **B3** recruited randomly from that population

Figure 2-1
Enabling Technology Treatments

Figure 2-2 illustrates how customers were recruited by FirstEnergy to participate as treatment subjects or controls. About 44,000 Illumination Company residential customers are located in the SGIG study area, of which 15,000 were sent surveys. There were 6,688 respondents to the survey (about 42% of those surveyed). Of that group, 1,189 were identified as having service levels or metering conditions that would not support the meter installation. The remaining 5,499 customers were offered the installation of a smart meter, of which 294 opted out.

This resulted in 5,204 study-eligible customers that were divided into those that had central air conditioning and a qualifying metering situation (4,429) and those that did not (671). A control group was drawn from each eligible group (250 customers for the PCT treatment group and 200 customers for the IHD group).

The remaining customers were recruited (making it an opt-in design) to participate in either the PCT treatment or the IHD treatment. Recruitment was accomplished using a combination of direct mail, e-mail, and phone solicitation. To fill the treatments, eligible customers were offered the chance to participate in waves in order to achieve the desired level of participation (Table 2-1). A group of customers was drawn from the pool of eligible customers and invited to participate. They were offered a choice of company or customer controlled PCT.

When the initial recruitment pool was exhausted, additional recruitment pools were drawn and those customers were contacted until the desired number of customers for each cell was achieved, or the overall pool of eligible customers was exhausted. Once a customer accepted the offer or indicated no interest, no further solicitations occurred. All customers contacted to participate received the same subscription engagement offer and provisions which had to be executed as a provision for study participation.

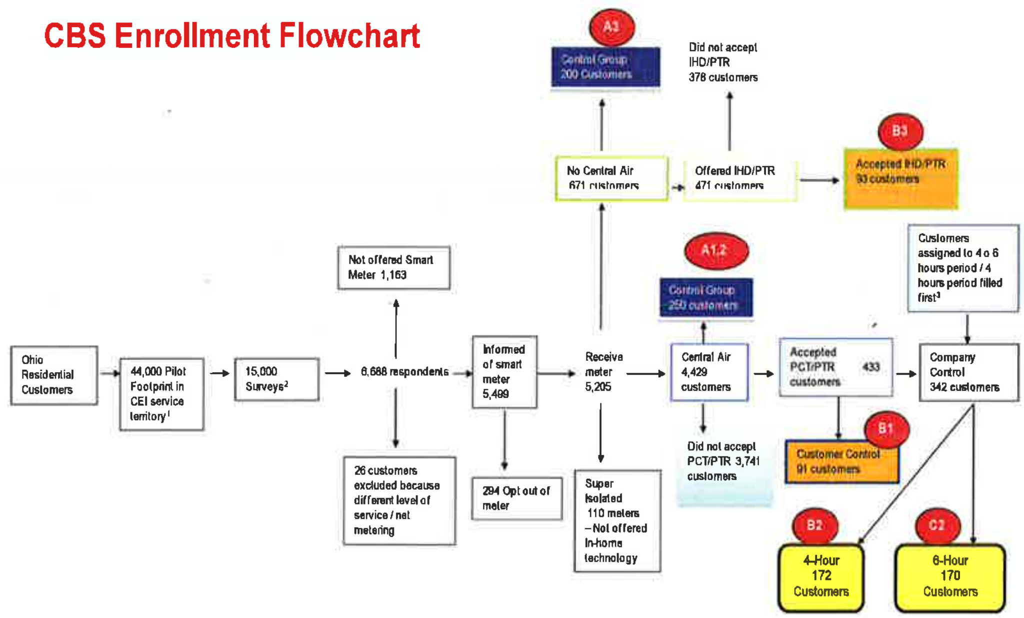


Figure 2-2
CBS Enrollment Flowchart

Customer Access to Information Regarding Their Usage

All customers (treatment and control) who participated in the CBS study were provided access to their daily usage through an online tool, the Aclara Home Energy Analyzer software, available at the FirstEnergy web page. In addition, they can download their daily usage into an Excel file. Historical information is available for up to 15 months after the meter was installed and communicating. An additional feature is that with this tool, all study participants are able to view their prior day's usage and, if there is an event, they are provided with an estimate of their peak time rebate payment.[5]

Project Schedule and Timeline

AMI meters were installed in the spring of 2011 at 5,205 premises with the intent to collect a baseline of information during the summer of 2011. No information regarding the upcoming pricing program was provided to the customers at the time of installation.

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[5] Because both treatment and control customers had access to the web page, its effect could not be distinguished.

After the summer of 2011, FirstEnergy began soliciting customers to participate in the program with the intent that the in-home technologies (PCT or IHD) could be installed, sufficient testing completed, and data collection and billing processes would be in place so that the PTR program could commence on June 1, 2012.

Figure 2-3 illustrates FirstEnergy's schedule and timeline for Phase 1 activities.

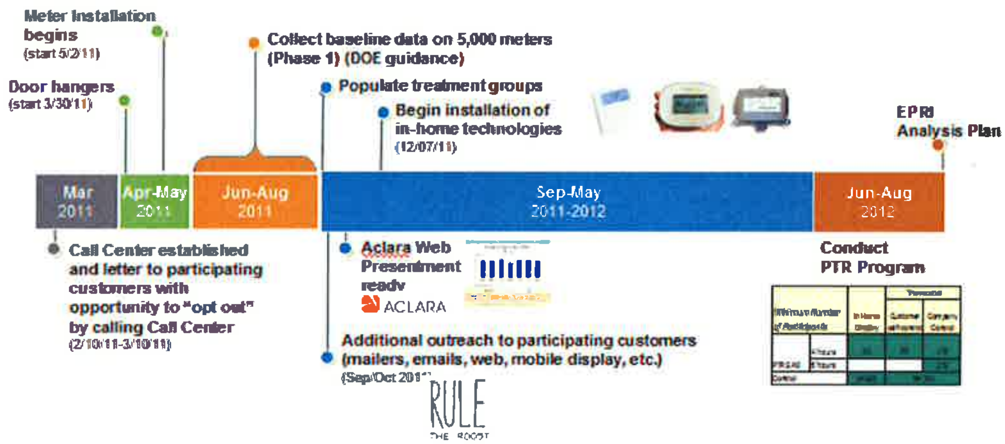

Figure 2-3
Schedule for Phase 1

Customer Recruitment

Customers were recruited using a combination of direct mail, e-mail, and telephone marketing efforts though six waves for B1, B2, and C2 (PCT) and one wave for B3 (IHD). Table 2-1 below contains the percentages of customers from which the Company was able to get an affirmative accept, decline or not eligible response out of the total number that were sent the marketing materials, and the level of customer acceptance with each marketing campaign.

About 50% of those sent marketing materials for participation in a PTR treatment followed up with FirstEnergy and were offered participation, approximately 22% of which enrolled in a treatment resulting in an overall recruitment rate from the target population of 11%. For the IHD treatment, 35% of those marketed engaged in a participation discussion and 19% of those enrolled in treatment B3.

An attempt was made to contact all customers (except customers in the control groups) through direct mail, e-mail and outbound calling. The level of customer retention were very high. Of the 533 customers who were subscribed to treatments initially, only seven had their devices removed prior to program inception.

Table 2-1
Recruitment of Customers into Treatments

Technology	Date	Marketed	Percent Contacted	Percent Enrolled	Percent Not Eligible	Percent Not Interested
Thermostat	10/5/2011	520	55%	11%	1%	43%
Thermostat	11/9/2011	100	52%	6%	2%	43%
Thermostat	12/5/2011	1600	48%	10%	2%	34%
Thermostat	12/30/2011	1000	64%	14%	3%	46%
Thermostat	2/24/2012	851	37%	10%	1%	25%
Thermostat	5/1/2012	103	20%	4%	1%	16%
In Home Display	2/17/2012	471	35%	19%	0%	16%

Customer Survey Approach

The Company administered three surveys during the study. The pre-treatment survey was an appliance survey to prequalify customers for treatment. This survey also captured demographic and household information. The second survey, a post-treatment survey, was administered to program participants (treatment subjects) at the end of year 1 in order to obtain their reactions and feelings toward the program. Customers who chose not to participate were also surveyed to get more information about why these customers did not want to participate in the program. A third survey was conducted following year 3 of the program.[6]

Subsequent Year CBS Administration and Impact Evaluation

The study was continued in the summers of 2013 and 2014 employing the same experimental design for participants that remained in the program, which is discussed in the next sections.

FirstEnergy commissioned EPRI to conduct a preliminary analysis of the summer 2012 impacts in order to support a decision by the PUCO on whether Phase II, involving up to an additional 39,000 customers, would go forward. The results of the 2012 impact study were published.[7] A preliminary study in 2013 compared the first two year's results. This report analyses participant responses in each year and looks for persistence, and changes in the character or level of response over the three-year study period.

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[6] The survey instruments are available upon request.

[7] EPRI 2012.

Section 3: CBS Study Participation and Weather Data

This section summarizes participation in study treatments and weather conditions over the three-year study period.

Participants

The study uses data from participants in the Phase 1 CBS that was operated by FirstEnergy in the summers of 2012, 2013, and 2014 when PTR events could be declared. Figure 3-1 compares the eligible customers by study year and by treatment. The Y-axis indicates the number of customers for each category. The X-axis distinguishes the control group and the five treatment groups, further differentiated by study year (2012, 2013, and 2014).

Generally, the initially recruited treatment participants remained in the study all three years. Due to either program attrition or filtering customers with problematic data, customers available for analysis dropped slightly in all treatment groups from 2012 to 2013, but rebounded somewhat in 2014 as metering data issues improved and attrition remained low.

A participants was excluded from the analysis if greater than 2 percent of its hourly observations are equal to zero during intervals that are not associated with suspected outages or meter failures. This was the case for about 8 percent of all participants, except in 2013. In that year, the number of excluded customers was noticeably higher for the PCT control group (declined to 233 from 250 originally recruited), the IHD control group (declined from 93 to 81), and the treatment groups involving the utility-controlled PCTs (treatment groups B2 and C2).

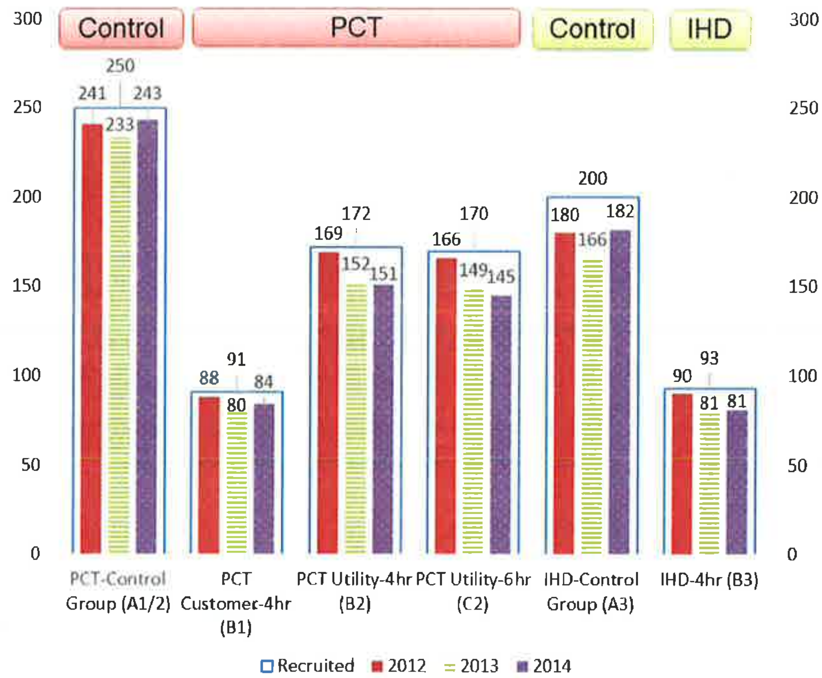


Figure 3-1
CBS Phase 1 Study Data Participation: Summer 2012, 2013, and 2014

Metering problems (as illustrated in Figure 3-2) prevented some participants from getting the PTR event notice for some 2013 events. As a result, their PCT was not adjusted automatically (raised 3 degrees) during events, and their loads on those days were not recorded. The result was some missing data for those treatments. Additional detail on the accounts included each year is provided in Appendix A.

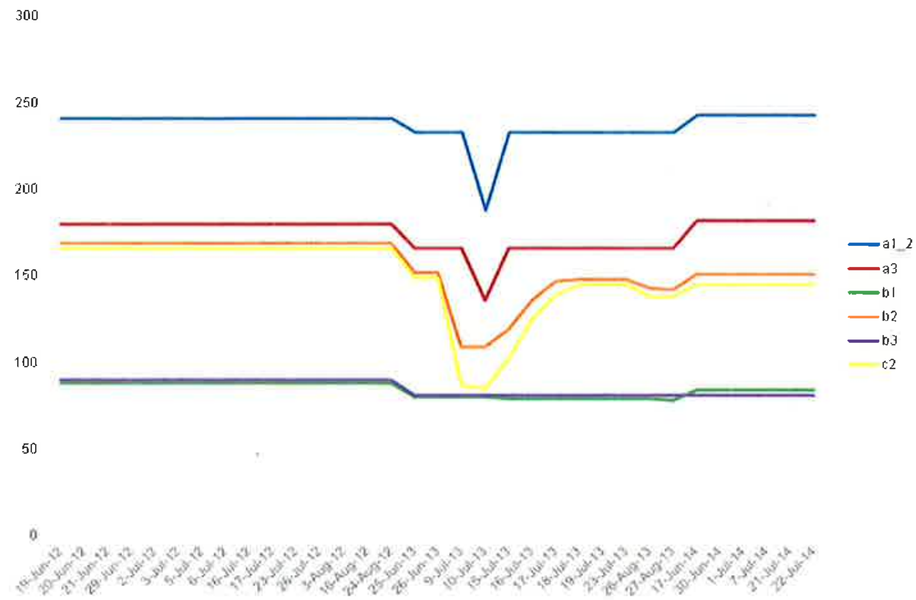
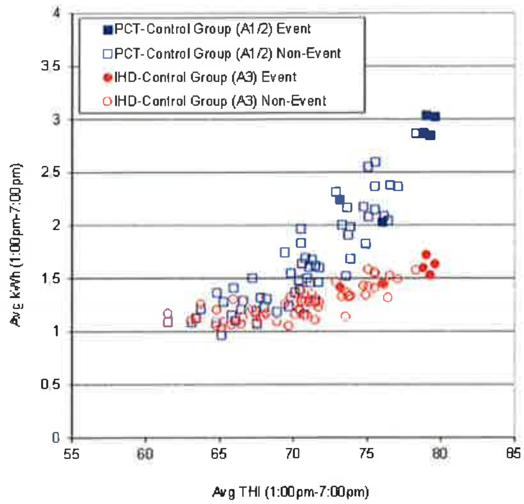


Figure 3-2
Phase 1 Study Data Participation: Event-Day Participant Counts

Weather Effects

Figure 3-3 graphs average event period load against the temperature-humidity index (THI) for each day in 2014. Usage for both control groups (which provides an indication of the amount of load available to be reduced on event days) is strongly related to temperature, as expected.[8] The highest loads are on the hottest days. Note the smaller usage difference for IHD customers on event (hot) days compared to those with PCTs; they do not have central air conditioning so they have smaller loads and are presumptively less weather sensitive.

[8] Two control groups were required because the population sample frame was partitioned into those with central AC and those without it. The former were offered a treatment that provided a PCT. The latter were offered an in-home display. Both were enrolled in the PTR program. Control groups for each partition were drawn before recruitment began. The preliminary report provides details (EPRI 2012).



			Average Hourly	
Event #	Event Date	THI1-7pm)	A1/2 kWh (1-7pm)	A3 kWh (1-7pm)
1	17-Jun-14	79.3	2.85	1.53
2	30-Jun-14	79.0	3.04	1.72
3	1-Jul-14	79.6	3.02	1.63
4	7-Jul-14	76.0	2.03	1.45
5	21-Jul-14	73.2	2.24	1.42
6	22-Jul-14	78.8	2.87	1.60

Key to graph

Solid data points = 2014 Event days

Hollow data points = 2014 Non-Event days

Blue squares = PCT Control Group (A1/2)

Red circles = IHD Control Group (A3)

Figure 3-3
Weather and Control Group kWh – Event vs Non-Event days 2014

Average Usage

Overall summer electricity usage was lower in 2013 and 2014 than 2012 for all treatments, largely due to cooler weather (Figure 3-4). In most cases, 2014 saw a slight increase in average hourly usage over 2013, despite a milder summer.

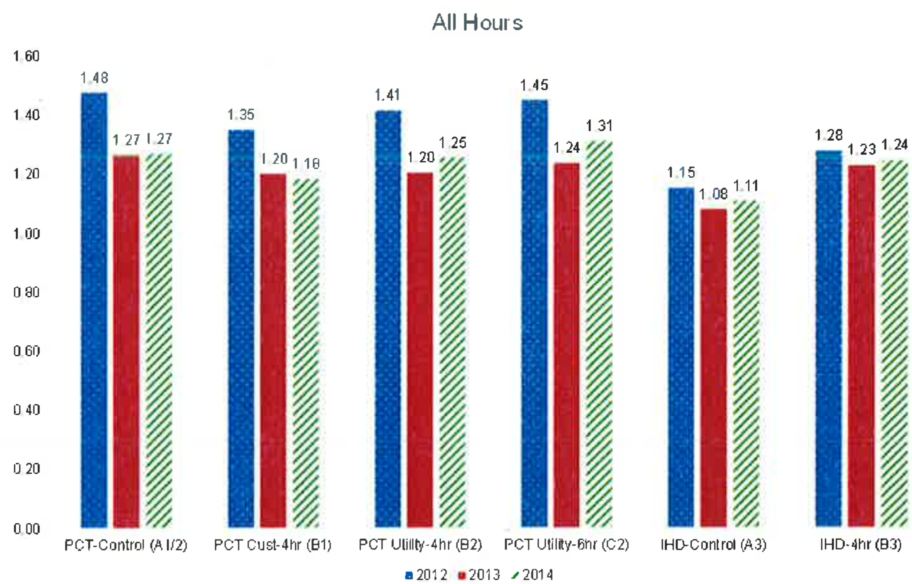


Figure 3-4
CBS Study Data Overview 2012, 2013, and 2014 – Average Hourly kWh All Summer Hours

The peak-to-off peak usage ratio declined in 2013 relative to 2012 (reflecting larger reductions in peak-period usage compared to off-peak usage) but increased for most treatments from 2013 to 2014 (Figure 3-5).[9] The decrease in 2013 is consistent with more mild weather that required less peak AC operation. The increase in 2014 is at odds with relatively milder 2014 weather. However, the differences are modest – a ratio change of about 0.02 to 0.06 from 2013 to 2014, less than 4 percent.

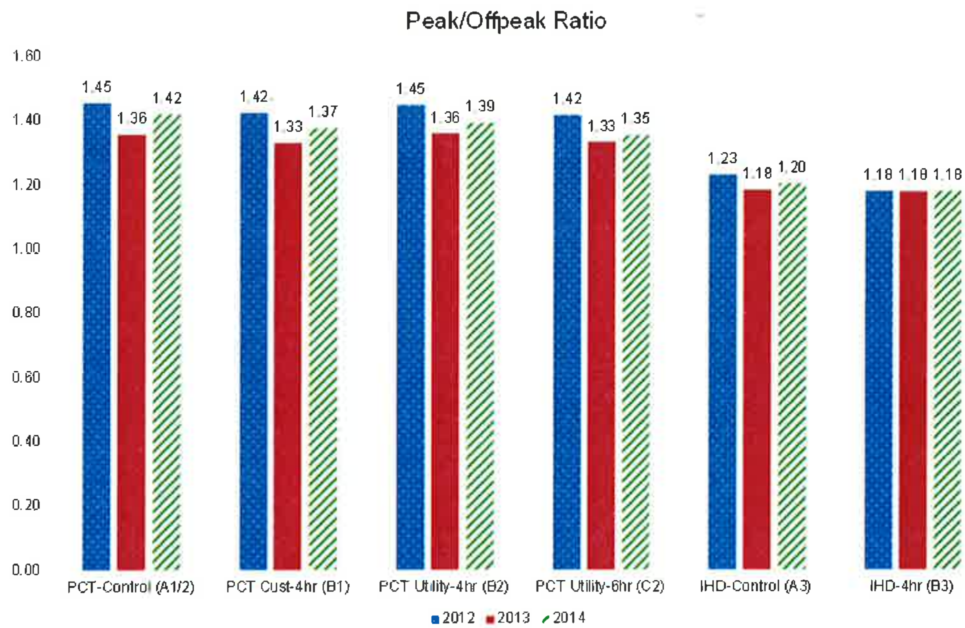


Figure 3-5
CBS Study Data Overview 2012, 2013, and 2014 – Average Hourly Peak to Off-peak Usage Ratio

Summer and Event Day Temperatures

The graph in Figure 3-6 shows average temperature, by hour, for the summer months of 2012, 2013, and 2014. It provides another indication of the cooler weather in 2013 compared to 2012, and even cooler weather in 2014. Cooler weather reduces air conditioning loads, which likely are the primary means of responding to events in all but the IHD treatment.[10] All other things equal, load reductions on event days should be lower in 2013 and 2014.[11]

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[9] The peak to off-peak usage ratio is based on the average hourly usage during each pricing period.

[10] Reduced window AC use may have been a way for these participants to reduce loads during events.

[11] Average temperatures were lower in every summer month of 2013 compared to 2012. The same holds for 2014 compared to 2013, most notably for the afternoon (event) hours (12 – 18).

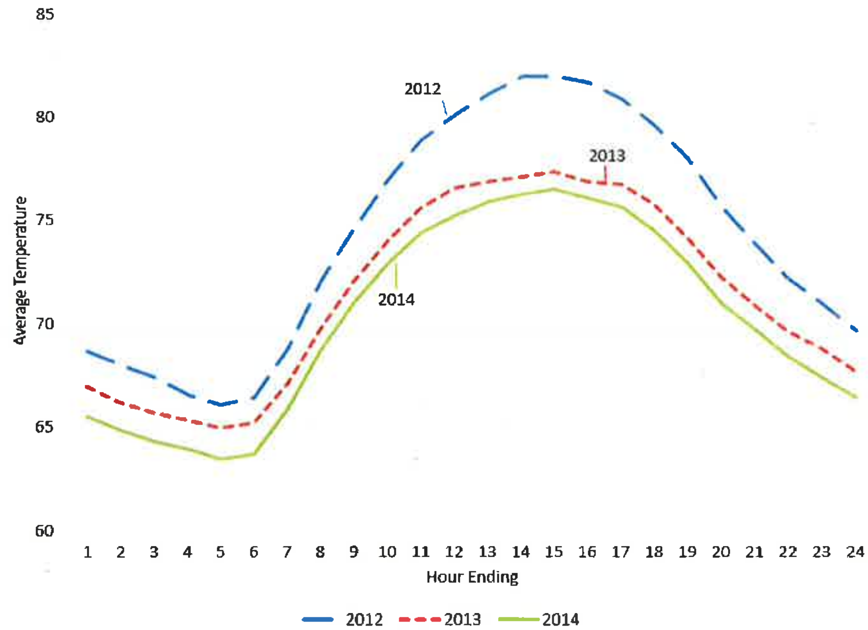

Figure 3-6
Average Summer Temperatures, 2012-2014

Figure 3-7 shows average event day peak period (1:00-7:00 p.m.) temperatures and usage in all three study years. Temperatures were similar between 2012 and 2013, with many events in the 76-80 degree range, but also a handful above and below. There were no extremely hot event days in 2014 and only one mild event.

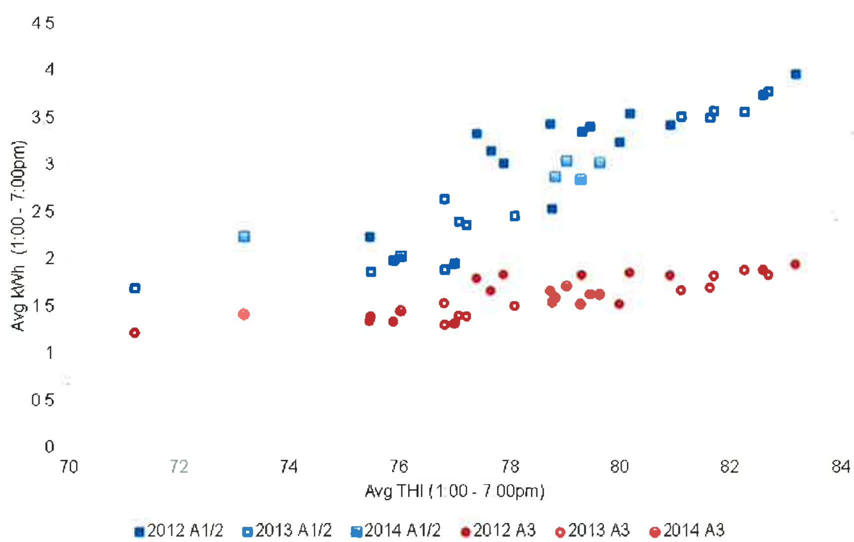

Figure 3-7
Control Group Average Hourly THI vs Average kWh on Event Days

Figure 3-8 displays average hourly usage on non-event days in 2014. PCT control group loads (A1/2) are higher than PCT treatment loads during most hours. Exceptions are treatment C2 (utility PCT control, 6-hour) in the morning hours between 5:00 and 10:00 a.m. and in a late peak hour between 9:00 and 10:00 p.m. Both utility-controlled PCT treatments, B2 (utility PCT control, 4-hour) and C2 (utility PCT control, 6-hour), are well aligned, but C2 loads tend to be higher in most hours. Treatment B1 load (customer PCT control, 4-hour) is lower than its control group (A1/2) during many hours of the day. This could indicate that selection issues (customers chose treatment B1 over B2 or C2) affected the treatment load profile, preventing a resolute comparison of B1 treatment loads to A1/2 control loads, but this could also indicate use of the technology to adjust event usage.

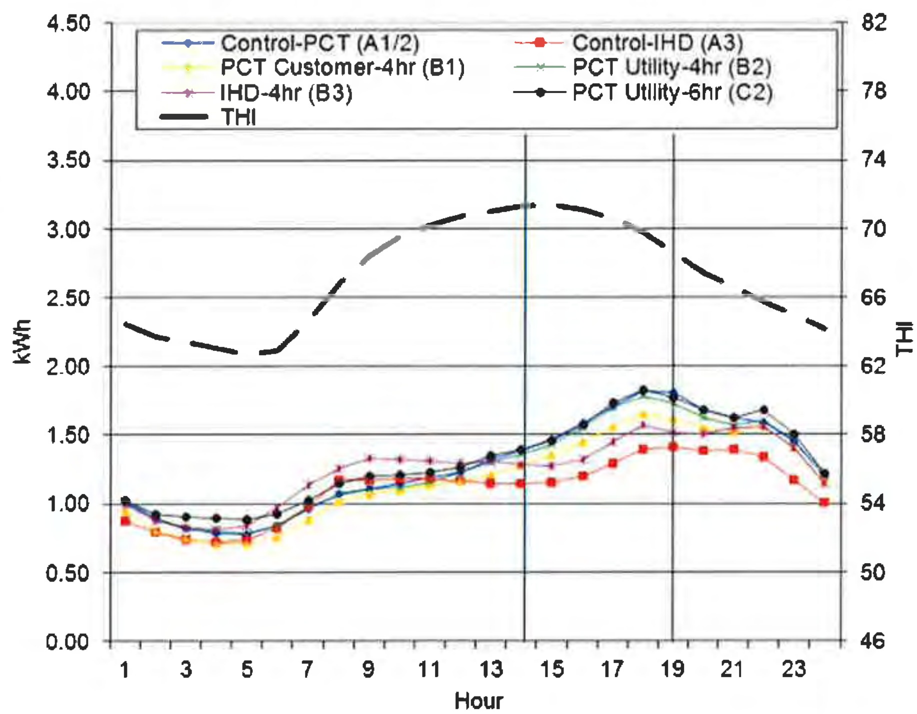

Figure 3-8
Average Hourly Loads 2014 — Control and Treatment — Non-Event Days

Treatment B3 (IHD+PTR, 4-hour) customers use more in all hours than their control customers (A3), but the load shape is very similar for the two groups. The lower overall load profile also reflects the fact that these customers do not have central AC (whereas PCT customers do), preventing a direct comparison of customers with PCTs with those with IHD.

Figure 3-9 displays control and treatment loads on hot non-event days in 2014. "Hot" days are those days where the temperature was close to that of event days, but no event was called.[12] Event-like (i.e., hot) non-event day loads display similar patterns to those observed in Figure 3-8. Overall load levels are higher, but treatment B1 is still below A1/2 and treatment B3 is still higher than A3.

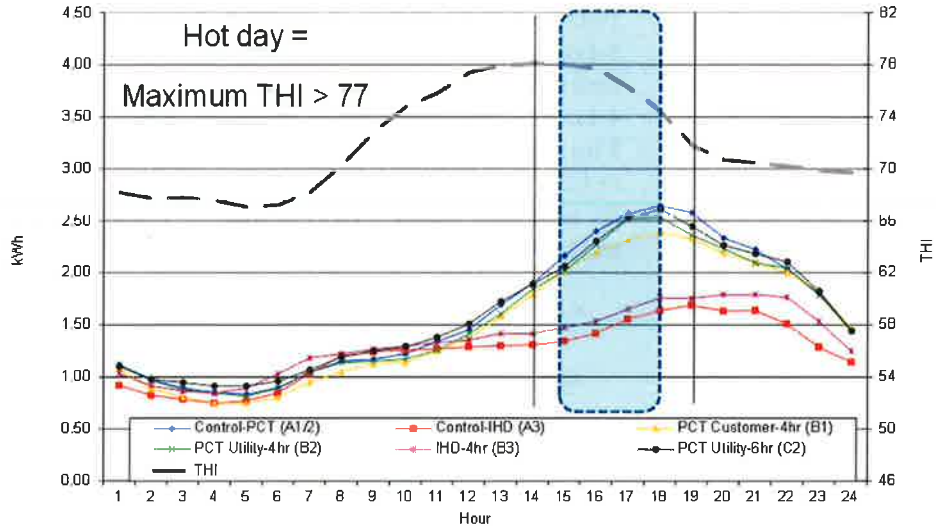

Figure 3-9
Average Control and Treatment Hourly Loads 2014 — Hot Non-Event Days

Figure 3-10 shows the average load profile for the control and treatment cells over all six event days in 2014. Treatments B2 and C2 (the two utility controlled PCT treatments) show clear event-hour "notches" (distinctly lower loads during the event hours) indicating demand response during event hours. Both treatments exhibit post-event "snap-back" (distinctly higher loads just after the event ends). Treatment B1 (customer controlled PCT) loads are lower than A1/2 (control) loads, but recall that they are somewhat lower on non-event days as well.

[12] FirstEnergy employed a forecasting model to predict high temperature days and determine whether to call an event based on the estimate.

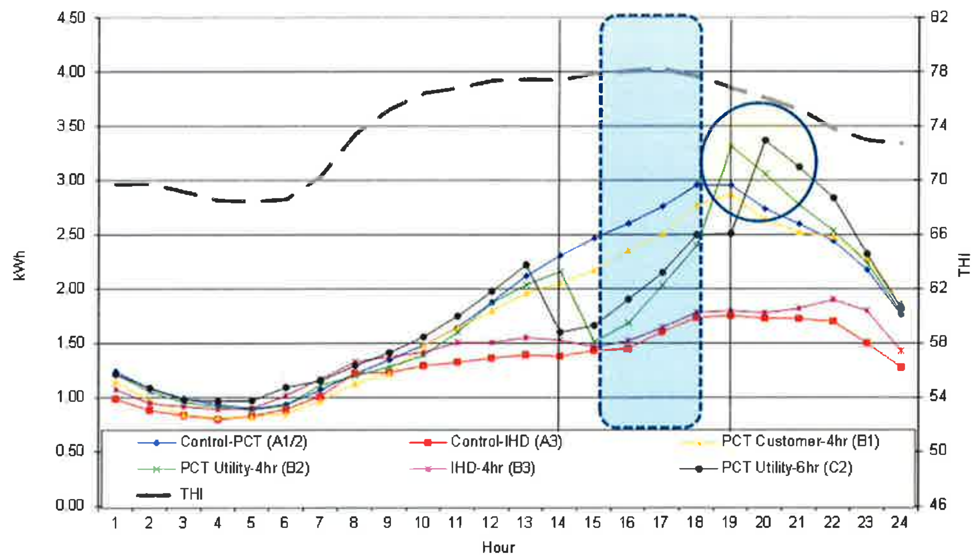

Figure 3-10
Average Control and Treatment Hourly Loads 2014 — Six Event Days

Treatment B3 (IHD only) loads appear to change shape during events, dropping almost as low as the control (A3) treatment in some hours. In summary, graphic comparisons suggest response to the PTR rebate incentive, especially for utility controlled PCT. Analytic models are required to quantify event load reductions and measure its persistence.

Section 4: CBS Impact Analyses

Two approaches were used to estimate the level and significance of load impacts during PTR events: a fixed effects model and an electricity demand model. The former provides estimates of hourly kWh changes attributable to the treatments. The latter provides an estimate of the substitution elasticity, a measure of how event prices affect event loads. The section begins with model descriptions and then discusses their estimation and implications.

Fixed Effects Regression Model

The idea behind the fixed effects model is that there are differences among customers that affect their usage level, absent the treatment, and a failure to account for these factors can bias estimates of the treatment effects. The fixed effects model accounts for differences in customer characteristics that are constant during the study period, potentially improving estimation of treatment effects.[13]

The fixed effects model employed in this study:

- Accounts for differences between treatment and control groups on non-event days
- Uses hourly observations for each customer
- Allows estimating a separate model for each hour of the day (and therefore each event hour)
- Each model pairs a treatment with its control group (e.g., B1 and A1/2)
- Includes a customer-specific fixed effect that controls for unobserved factors that are assumed to be constant across the study period.

Identically structured fixed effects models were estimated for each hour for the summers of 2012, 2013, and 2014 distinguishing between control and treatment customers. Estimating hourly models allows estimating overall treatment effects (the load change during events). It also facilitates examining persistence over the event (the initial hour load change versus that of subsequent hours) and determining if there were anticipatory or remediation behaviors. The former refers to customers adjusting loads before the event, which might be the case for

[13] For a discussion of methods for quantifying the effect of consumer behavior experiments involving electricity demand, see EPRI 3002001870.

the customer control treatment (B1), some evidence of which was found in the preliminary 2012 study. The latter refers to snap back, increased loads (over what would be normal) in the hours immediately following an event resulting from AC equipment operating to restore the premise to the desired temperature (overcoming heat buildup). The 2012 preliminary study concluded this was the case for the two utility-controlled treatments (B2 and C2).

Separate models are estimated for each of the four pair-wise combinations of treatment and control cells (i.e., A1|2 and B1, A1|2 and B2, A3 and B3, and A1|2 and C2) and each hour of the day (hours ending 1 through 24) resulting in 96 hourly models for each year. Only non-holiday weekdays during the months of June through August are included in each model. First-order serial correlation was accounted for by estimating the fixed-effects model with AR(1) disturbances.[14] Each hourly regression model is specified as:

$$\begin{aligned} Q_{c,t} &= \alpha + \beta^{Evt} \times Event_t + \beta^{Evt\_Trt} \times (Event_t \times Treat_c) + \beta^{THI} \times THI_t \\ &+ \beta^{THI\_Trt} \times (THI_t \times Treat_c) + \beta^{THIMA} \times THIMA_t \\ &+ \beta^{THIMA\_Trt} \times (THIMA_t \times Treat_c) + \sum_{i=2}^{5} \beta_i^{DT} \times DType_t \\ &+ \sum_{i=2}^{5} \beta_i^{DT\_Trt} \times (DType_t \times Treat_c) + v_c + e_t \end{aligned}$$

Where:

$Q_{c,t}$ is the hour's usage for customer c on non-holiday weekday t;

α is the constant term;

The β's are estimated parameters;

$Event_t$ is an indicator variable that equals one if day t is an event day, and zero otherwise;

$Treat_c$ is an indicator variable that equals one if customer c is in the treatment (i.e. not control) group, and zero otherwise;

The coefficient on $Event_t \times Treat_c$, or β^{Evt_Trt}, is the difference-in-differences estimate of the event-day load impact;

THI_t is the temperature-humidity index for the model hour on current day t [15];

[14] Baltagi, B. H., and P. X. Wu. 1999. "Unequally spaced panel data regressions with AR (1) disturbances," *Econometric Theory* 15: 814-823.

[15] Temperature-Humidity Index (THI) = Temp – 0.55 * (1 – Relative Humidity) * (Temp – 58) (PJM, 2012 Load Forecasting and Analysis Manual).

$THIMA_t$ is the 24-hour moving average temperature-humidity index for the 24 hours prior to the model-hour on day t;

$DType_{i,t}$ is a series of dummy variables for each day of the week that equals one for the specific day of the week, and zero otherwise[16];

v_c is the fixed effect for customer c ; and

e_t is the error term.

This equation models customers' electricity usage as a function of weather conditions (represented by current-hour THI and a 24-hour moving average THI), type of day, and event day (because the PTR event day payment was the same for all events, a dummy variable distinguishes event day for estimating treatment effects). These effects are allowed to differ between customers in treatment and control groups through the inclusion of interaction terms created by multiplying each explanatory variable by an indicator variable for being in a particular treatment group (e.g., THI_t x $Treat_c$).

The $Event_t$ variable accounts for otherwise unexplained differences in usage on event-days for both treatment and control-group customers (e.g., if the included weather variables are not able to account fully for the event-day conditions). Our primary interest is the coefficient on the interaction term between $Event_t$ and $Treat_c$ (β^{Evt_Trt}) which represents the estimated PTR event-day treatment effect expressed in kWh.

Fixed Effects Model Estimates for 2014

Figure 4-1 shows fixed effects load impact estimates for 2014 for hours-ending noon to midnight.[17] In the table, the rows indicate event hours and the columns represent the treatments. The value for each hour/treatment is the estimated per-customer kWh load change for that hour and treatment.

[16] The i subscript denotes days of the week, where i = 2 represents Tuesday, i = 3 represents Wednesday, etc.

[17] A similar table including load impact estimates for all 24 hours is included in Appendix A.

	2014			
	Control Group versus:			
Hour	PCT Customer-4hr (B1)	PCT Utility-4hr (B2)	PCT Utility-6hr (C2)	IHD-4hr (B3)
12	0.016	0.054	0.062	0.086
13	0.001	-0.013	0.092	0.032
14	-0.09	-0.089	-0.699++	0.044
15	-0.115	-0.848++	-0.747++	-0.051
16	-0.023	-0.803++	-0.607++	0.033
17	0.012	-0.672++	-0.553++	-0.047
18	0.108	-0.439++	-0.407++	-0.051
19	0.177+	0.549++	-0.331++	-0.018
20	0.042	0.434++	0.666++	-0.037
21	0.045	0.301++	0.554++	0.051
22	0.08	0.126+	0.310++	0.011
23	0.185++	0.129++	0.169++	0.072
24	0.161++	0.041	0.090+	0.042
Event Average	-0.005	-0.691	-0.557	-0.029

Values in the table represent hourly event load impacts measured in kWh.

++ $p<0.01$, + $p<0.05$

- B2 and C2 have statistically significant load reductions in all event hours.
- B2 and C2 also both show load increases in post-event hours.
- The net impact of statistically significant event and post-event hour estimates are -1.22 kWh for B2 and -1.56 kWh for C2.
- B1 and B3 have mixed positive and negative estimated load impacts during event hours but none are statistically significant.

Figure 4-1
Fixed Effects Model Results for 2014

For example, the hour 12 value for treatment cell B1 (PCT Customer-4 hr.) is 0.016, indicating that event days loads in that hour increased by 0.016 kW (16 watts, about equal to a compact fluorescence lightbulb) compared to non-event days. However, that estimated value is not significantly different from zero, so the event load impact in that hour is assumed to be zero.

In Figure 4-1, the statistical significance of an estimated kWh impact is indicated by the addition of a + or ++ symbol, corresponding to a p-value that connotes the level of significance (p=0.01 is a more stringent standard for statistical significance than p=0.05). Most of the statistically significant impacts (reduced hourly loads) are event hours (highlighted gray in Figure 3-1), but limited to utility controlled PCT treatments (B2 and C2). FirstEnergy sends a signal to the PCT at these premises at the commencement of an event that raises the thermostat setting 3 degrees above the setting at the time. If the customer has programmed the PCT to a daily routine then the temperature setting for 1:00 p.m. is raised 3 degrees (for example, from a current (pre-event) setting of 72 to 75 degrees) for the duration of the event.

Event notice is sent to these (and all treatment) customers a day prior. Customers in B2 and C2 treatments can override the event temperature setting increase.

There are significant load increases in hours following events for utility-controlled PCT-4 hour (post-event hours 19-24) and utility-controlled 6-hour (post-event hours 20-24) treatments, which suggests a snap-back effect. This is explored in more depth below when persistence is analyzed. There is no evidence of pre-event load changes for any treatment.

Figure 4-2 shows hourly event-day load changes by treatment, a plot of the values in Figure 4-1. Note that "hour-ending" means the value is for the hour that ends at the indicated time. For example, the hour ending 7:00 a.m. is the period 6:00 – 7:00 a.m. The B1 and B3 loads show mixed load reductions and some increases during event hours that are not statistically significant (hence assumed to be zero).

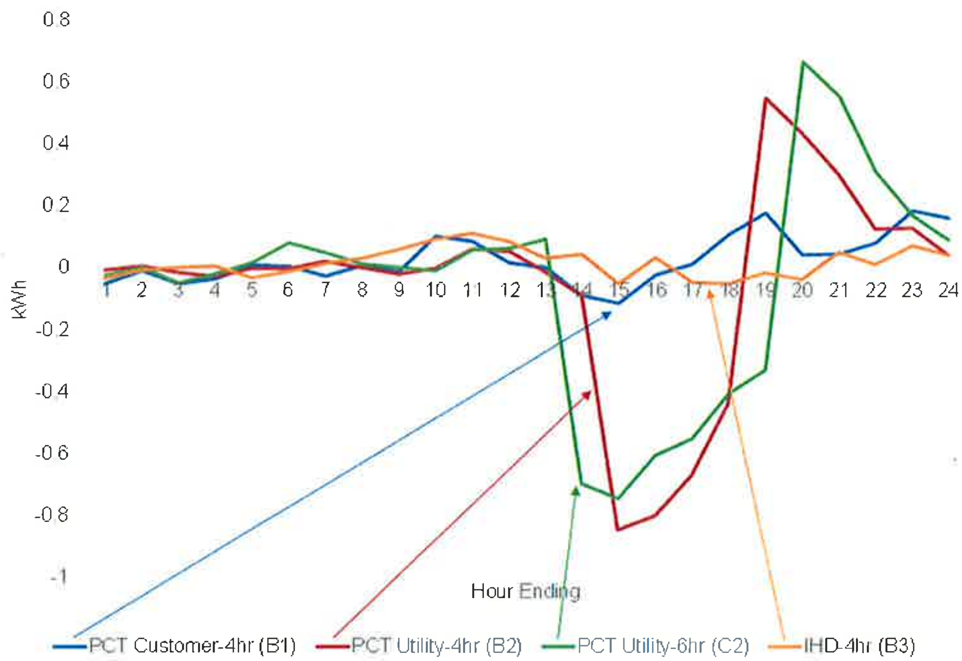

Figure 4-2
Fixed Effects 2014 Model Results – Average Hourly Event-day Loads

B2 and C2 (the two utility-controlled PCT treatments) show large event-hour load reductions and substantial snap-back in post-event hours. Notice that the load impacts for these treatments are large in the first event hour and drop off in subsequent event hours. This is due to FirstEnergy's practice of simultaneously raising at the commencement of the event the thermostat (PCT) for all participants in the B2 and C2 treatments (designated PCT-utility-controlled) three degrees from the programmed setting at the time of event commencement, then re-setting the PCT to its programmed temperature regime at the conclusion of the event.

During the event, when the premise reaches the higher temperature setting, the AC begins to operate to maintain that temperature. As a result, the load impact displays the AC-control technology's iconic shape. This is an effective load control strategy because the AC unit's operation is altered by the utility at the commencement of an event unless the participant takes an action to override that PCT control action. The next section discusses the extent of override behavior during events in all years, which was uncommon.

B1 (PCT-Customer 4 hour) customers show no indication of significant event-hour load reductions in 2014, but hour-ending 19 (6:00 to 7:00 p.m.) immediately following the event does show some evidence of post-event snap-back (which may be a statistical anomaly). This treatment group provides insight into customers' willingness to allow the utility to install a thermostat that is preprogrammed to achieve event temperature rises, and earn payments for voluntary curtailments. Relative to the utility-controlled PCT, it appears that most treatment B1 participants did not implement a temperature adjustment during events in 2014. This is at odds with what was found in 2012, when event load reductions were evident, as discussed below.

In summary, we estimated load reductions during 2014 events for the treatments wherein FirstEnergy controls the PCT and the participant has to take an action to countermand that instruction (B2 and C2). This was the case in the 2012 preliminary study and the case in 2013. The other treatments display no indication of an affirmative action to reduce load during events, which comports with the 2013 results, but are contrary to the positive, but substantially smaller, load impacts reported for 2012, as discussed next.

The following section explores year-to-year persistence by examining changes in event response over the three study years.

Persistence of Load Impacts

The CBS Phase I study, which involved several different PTR offerings, was launched in the summer of 2012. The study continued in the summers of 2013 and 2014 operating under the same design structure; three PCT treatments and one in-home display treatment each of which included an offer of a payment of $0.40/kWh for load curtailed during events.

Persistence in several forms can be measured across the three study years, including customer enrollment or attrition, the frequency of event opt-out behavior, and the extent to which load impacts observed in the first year are also observed in the second and third years. This section approaches measurement of persistence in a variety of ways, as follows:

- Persistence of load impacts across years
- Graphical depictions of estimated average hourly load impacts in each year
- 2012 vs. 2013 vs. 2014 meta-analysis
- Graphical depictions of 2012, 2013, and 2014 load impacts and weather for each treatment group and event day
- Examination of opt-out behavior
- Customer composition and missing data.

Figure 4-3 compares the fixed effects model estimates of average hourly event impacts for each treatment for each of the study years in level and percentage terms.

	Average Event LI (kWh)			Average Event % LI		
	2012	**2013**	**2014**	**2012**	**2013**	**2014**
PCT Customer-4hr (B1)	-0.223	-0.092	-0.005	-7.8%	-3.5%	-0.4%
PCT Utility-4hr (B2)	-0.845	-0.652	-0.691	-29.8%	-24.6%	-27.1%
PCT Utility-6hr (C2)	-0.769	-0.614	-0.557	-27.6%	-23.6%	-22.0%
IHD-4hr (B3)	-0.184	-0.011	-0.029	-10.5%	-0.5%	-1.7%

LI = load impact

Figure 4-3
Fixed Effects Model Average Hourly Load Impacts – 2012, 2013, and 2014

In percentage and level terms, load impacts are highest in all treatments in 2012. The 2014 load impacts are lower than those in 2013 for C2 and are higher than 2013 for B2. There are few statistically significant load reductions in 2013 and 2014 for treatments B1 and B3, suggesting that over time these customers became less inclined to respond to events. As discussed below, the electricity demand model provides a contradictory view of impacts for those treatments. A graphical depiction of load impacts by treatment group and year is provided in Figures 4-4, 4-5, 4-6, and 4-7.

For the customer-controlled PCT 4-hour treatment (Figure 4-4), 2013 and 2014 event load reductions are lower than those of 2012 and are not statistically significant (they were statistically significant in 2012).

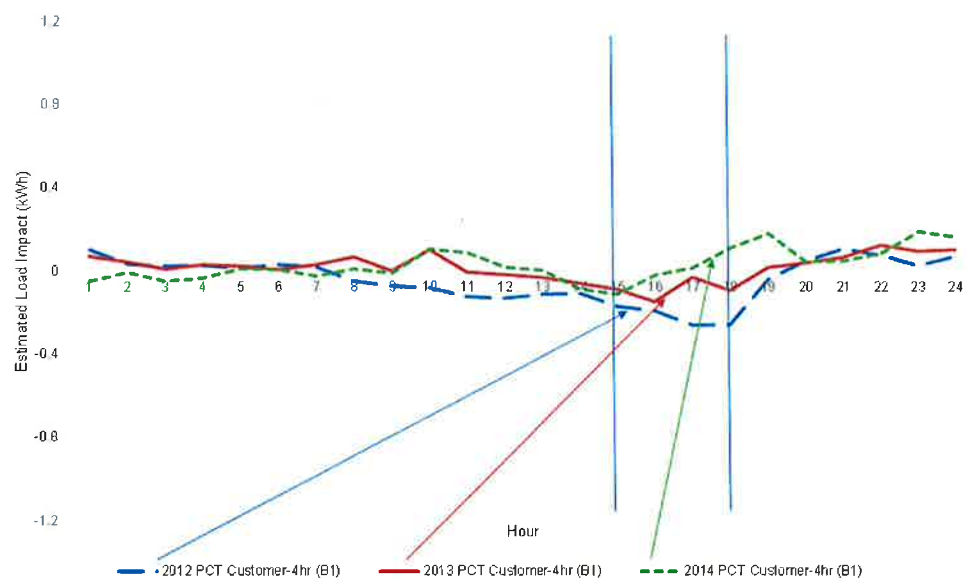

Figure 4-4
Study Period Load Impact Persistence for Customer 4-hour PCT (B1)

Figure 4-5 illustrates load impact persistence for the utility-controlled PCT 4-hour treatment (B2). The largest load reduction during events was in 2012, with slightly smaller differences between 2013 and 2014. Years 2012 and 2014 have similar patterns of load reduction. The largest reduction occurs in the first event hour, slowly trailing off in each subsequent hour of the event. The hourly impacts in 2013 follow the same general pattern, but there was a larger estimated load reduction in the second event hour relative to the first, which may be an anomaly.

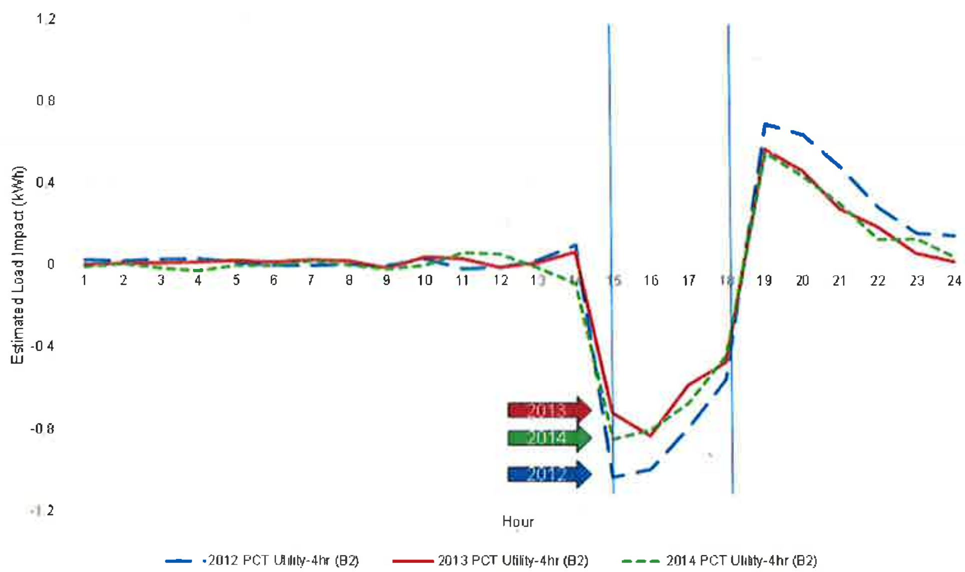

Figure 4-5
Study Period Load Impact Persistence for Utility Controlled (4-hour) PCT (B2)

Load impact persistence for the utility-controlled PCT 6-hour treatment (C2) is illustrated in Figure 4-6. The first year, 2012, has the largest event-hour load reductions, followed by 2013 and then 2014. All three years have similar patterns of load reduction. The largest reduction occurs in the first event hour, slowly trailing off throughout the event.

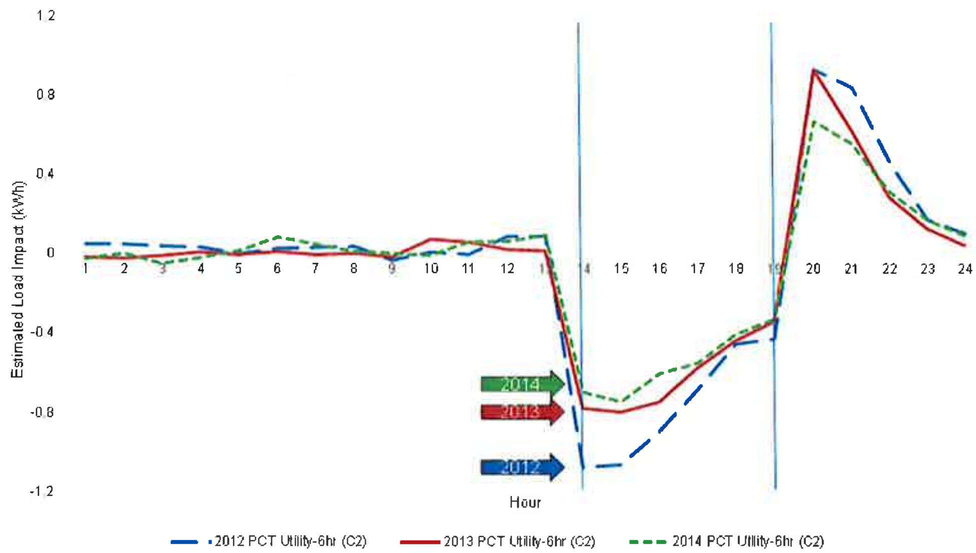

Figure 4-6
Study Period Load Impact Persistence for Utility Controlled (6-hour) PCT

For the IHD treatment (B3), there were no statistically significant load impacts in the fixed effects model for 2013 and 2014, in contrast to small but statistically significant load reductions in 2012 (Figure 4-7).

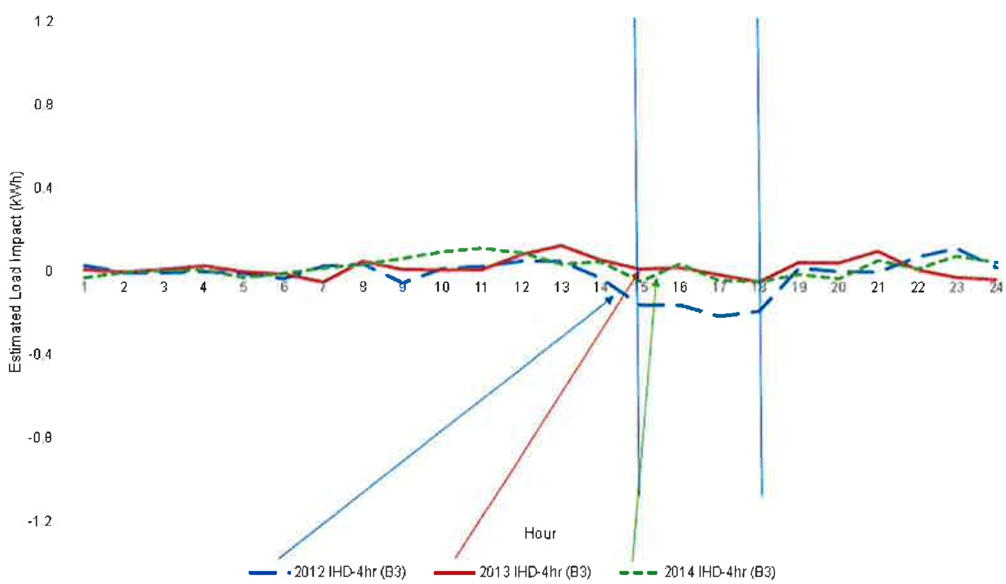

Figure 4-7
Study Period Load Impact Persistence for IHD (B3)

Explanations for Persistence

Estimated load impacts were lower in 2013 and 2014 than in 2012 for all treatment groups, most prominently for the customer-controlled PCT treatment (B1) customers. Possible explanations include:

- Weather conditions: cooler temperatures in 2013 and 2014 may have produced less AC load to curtail during events, which may have led to lower impacts when the PCT temperature set points were changed (either by FirstEnergy or the participants).
- Event override behavior exhibited by utility-controlled PCT participants (overriding the thermostat setting increase) may have changed across years.

To evaluate these explanations and explore the effect of other event-day characteristics on load response (e.g., whether the prior day was also an event), we estimated treatment-specific regressions of estimated load impacts on a set of variables that characterize the event days, as described below.

Regression Model of Load Impact Persistence

Regressions were estimated for each treatment group using the average event-hour load impact as the dependent variable.[18] The explanatory variables include: the average event-hour THI; indicator variables for 2013 and 2014; the number of event opt-outs (B2 and C2 only); whether the prior day was also an event day ("consecutive"); an event trend variable to explore whether load impacts increased or decreased as the summer season progressed; and a variable to account for events that were called close to the 4th of July (which may have affected customer response due to vacations or other holiday-related behavior). The estimated model is:

$$AvgLI_t = \alpha + \beta^{THI} * THI + \beta^{2013} * yr2013 + \beta^{2014} * yr2014 + \beta^{OptOut} * optouts + \beta^{consec} * consecutive + \beta^{trend} * trend + \beta^{Fourth} * FourthJuly + \varepsilon$$

Where:

AvgLI = Average modelled hourly load impact estimate (kWh) for event *t*,

THI = Temperature-Humidity Index (event average),

yr2013 = indicator variable, equal to 1 if 2013 and 0 otherwise,

yr2014 = indicator variable, equal to 1 if 2014 and 0 otherwise;

[18] Specifically, the dependent variable is the average of the hourly coefficients during the event hours of each event day, from the fixed-effects models described at the beginning of Section 4. Separate models are developed and estimated for each treatment group.

optouts = the number of event opt-outs (B2 and C2 only);

consecutive = 1 if the previous day was an event day and 0 otherwise;

trend = 1 for the first event of the year, increasing by 1 for each subsequent event;

FourthJuly = 1 for the following event dates: July 2, 3, 5, and 6 of 2012; and July 1 and 7 of 2014 and = otherwise; and

α is a constant term, βs are estimated parameters, and ε is the error term.[19]

Figure 4-8 contains estimated persistence model coefficients. The listed values are the estimated effect of each variable on the average-event hour load impacts. The first row indicates the effect of weather on each treatment's load impact. The THI coefficient estimates are positive and statistically significant in the first three columns, indicating that load impacts are higher (larger load reductions) on hotter days for PCT treatment customers. The weather effect is slightly negative (indicating smaller load impacts) but not statistically significant for the IHD treatment.

Variable	PCT Customer 4-hr (B1)	PCT Utility 4-hr (B2)	PCT Utility 6-hr (C2)	IHD 4-hr (B3)
THI	0.015+	0.033++	0.037++	-0.005
Year=2013	-0.163++	-0.284++	-0.217++	-0.207++
Year=2014	-0.221++	-0.170	-0.203	-0.204++
# opt-outs	n/a	0.010	0.006	n/a
Consecutive Event	0.055	-0.031	-0.016	-0.030
Event Trend	-0.016++	-0.036++	-0.016++	-0.004
Near 4th of July	-0.090	-0.208++	-0.096	-0.016
Constant	-0.824	-1.501	-2.045++	0.662
Number of observations	33	33	33	33
R-squared	0.57	0.64	0.63	0.60

+ p-value < 0.10
++ p-value < 0.05
P-value is a measure of statistical significance of the estimate. The lower the value the higher the significance.

Figure 4-8
Persistence Meta-Analysis Results

[19] The models were estimated using Ordinary Least Squares.

The next two rows provide the estimates of the difference between the load impacts of 2013 and 2014 compared to 2012. For example, the -0.163 coefficient for the B1 group in 2013 means that 2013 load impacts were -0.163 kWh per hour lower in 2013 than in 2012 for that group, and the difference is significant.

Controlling for weather, 2013 had lower load impacts than 2012 in all treatments: all of the coefficients in the second row of Figure 4-8 are negative and all are statistically significant.

The results were more mixed in 2014, indicating even lower load impacts in 2014 versus 2013 for B1 and B3, which was not the case for the utility-controlled PCT groups (B2 and C2).

The estimates indicating lower response in 2013 are particularly difficult to explain for the utility-controlled PCT treatment groups, since we would expect the majority of their response to be automated through the PCT and therefore largely affected by weather or opt-out behavior, which are both accounted for in the regressions described above. This suggests that other forces affected the amount of demand response for these customers in 2013 relative to 2012.

Possible explanations include: a change in non-AC usage behavior that resulted from customer experiences during 2012; or that 2012 demand response was influenced by participation in the program (a Hawthorne effect) that was less prevalent in 2013. That is, under this (unconfirmed) theory, treatment participants were eager to perform in the first year both because they would be paid for doing so, and because they wanted to act as they thought they were expected to perform based on their understanding of the CBS study. The effect wore off in subsequent years as the program education components became more distant in time, and perhaps because the payments they received were less than they anticipated.

The next two rows of Figure 4-8 show that there is no effect on load impacts associated with the number of event opt-outs, which is only relevant for the utility-controlled PCT groups. The same holds for when the event day was preceded by another event.

The "event trend" variable provides some evidence for within-season response fatigue for the central AC treatment groups. It is not clear why this is the case for B2 and C2 given that opt-outs are included in the models. Perhaps non-AC load reductions become smaller as the season goes on.

Finally, only the B2 customers experienced lower load response on the event days that occurred near the Fourth of July. This could occur because customers went on vacation during that time, perhaps turning off their central AC while they were gone. This effect is only statistically significant for one of the three treatment groups with central AC.

To help illustrate load impact persistence over time and its relationship with weather conditions, Figures 4-9, 4-10, 4-11, and 4-12 show average event-period THI (yellow line) and load reductions (blue bars, positive value = load reduction) for each event in 2012, 2013, and 2014. Figure 4-13 helps summarize Figures 4-9 to 4-12 by displaying hourly load response by study year for both event reductions and snap back.

In these figures:

- The solid line plots THI over three years of events.
- The bars indicate the average estimated load impact for each event in each year (15 for 2012, 12 for 2013, and 6 for 2014).
- The confidence interval for each day's estimate is indicated by the narrow line set inside each bar. In the analysis that follows, an event response is deemed statistically significant only if the confidence interval does not include a negative value.

A visual inspection of the bar heights (average kWh load reduction) from left to right provides a perspective in the degree of study period (2012-2014) persistence.

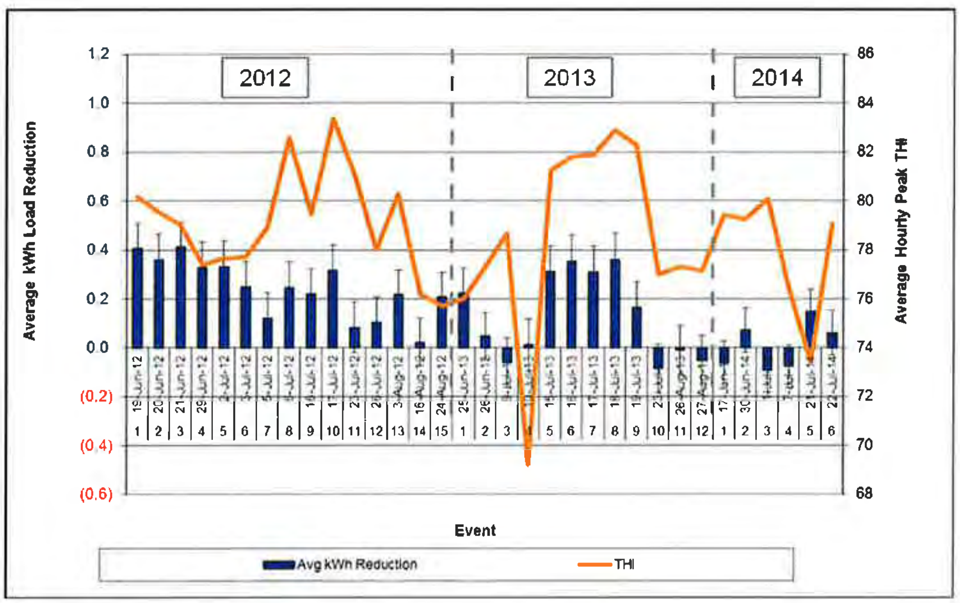

Figure 4-9
Persistence – Customer Control 4-hour Treatment (B1)

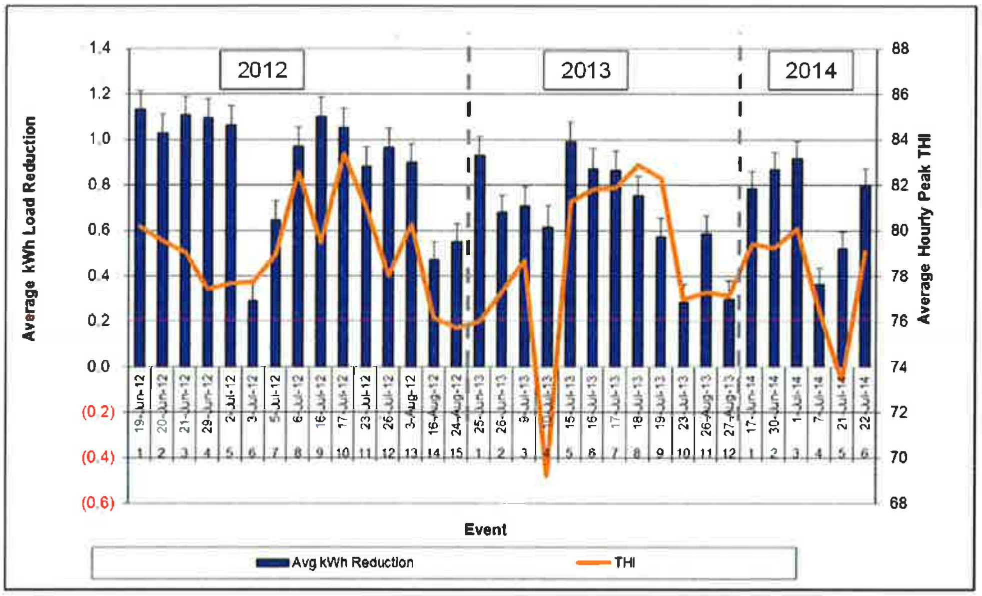

Figure 4-10
Persistence – PCT Utility Control 4-hour Treatment (B2)

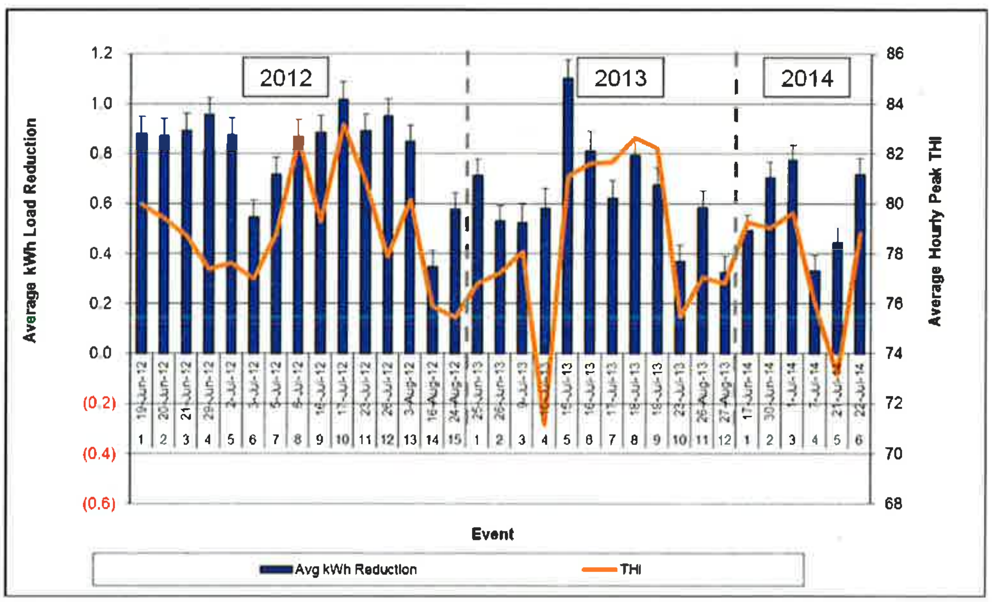

Figure 4-11
Persistence – PCT Utility Control 6-hour Treatment (C2)

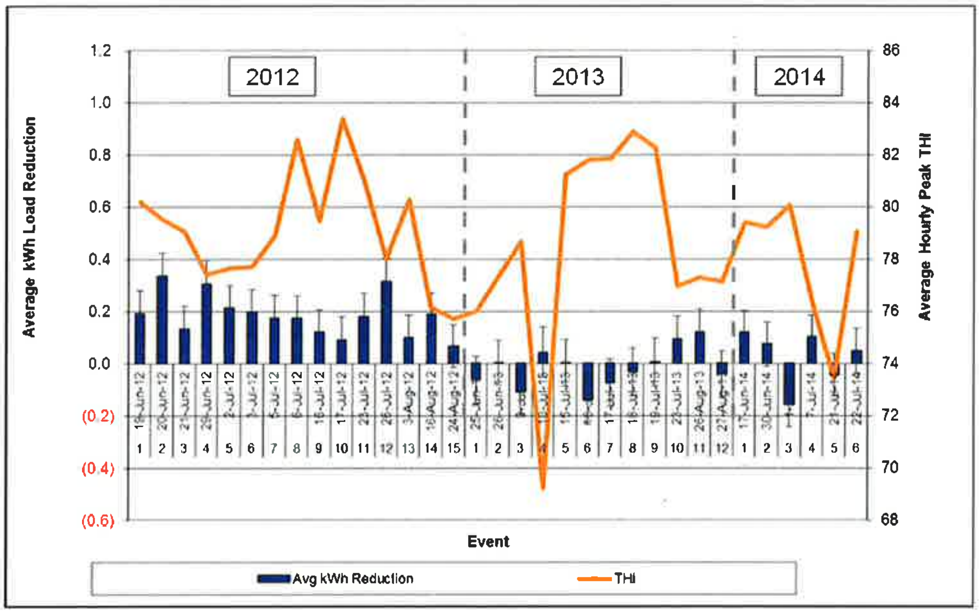

Figure 4-12
Persistence – In-Home Display (B3)

Fixed Effects Model Estimate of Impacts for Treatments for all Study Years									
			2012		2013		2014		
Treatment (a)		# Peak Hrs	# Hrs with Significant Reduction (b)	Snap-Back Hrs with Significant Load Increase (c)	# Hrs with Significant Reduction (b)	Snap-Back Hrs with Significant Load Increase (c)	# Hrs with Significant Reduction (b)	Snap-Back Hrs with Significant Load Increase (c)
B1	Customer PCT Control	4	4	none	4	none	0	none
B2	Utility PCT Control	4	4	19-24	4	19-22	4	19-23
C2	Utility PCT Control	6	6	20-24	6	20-23	6	20-24
B2	In-Home Display	4	4	23	0	none	0	None

Notes
(a) All treatments offer $.40/kWh reduced during PTR events
(b) Estimated fixed effect model coefficient significant at 10% level or better
©Hours with snap back indicated in 24-hour military time

Figure 4-13
Persistence within Study Years – Event Repose and Snap Back

General Observations on Persistence

Across the study period (2012-2014), persistence varied considerably across treatments:

- Treatments B2 and C2 (utility-controlled PCT) event response remained strong, dropping off only slightly. In every year, response was statistically significant in all event hours.

- Event treatment response fell of dramatically for B1 (customer-controlled PCT) and B3 (IHD) in 2013 and even more so in 2014. By 2014, there was little or no detectable response in either treatment.
- Snap back was robust for treatments B2 and C2 for all years, showing higher than normal loads for three to five hours after the event terminated, resulting in a reduction in the day's net kWh reduction by 20-30 percent.

Constant Elasticity of Demand (CES) Model

A fixed effects model estimates the treatment-induced load change in each hour of event days, controlling for customer characteristics that are constant during the analysis time frame and other included variables (e.g., weather conditions). As a result, the estimates are not necessarily consistent with utility theory, or any other conceptualization of how consumption decisions are made.

Generally, a fixed effects model is assumed to be locally consistent with utility theory. It is widely used to estimate impacts from both rigorously constructed experiments and natural experiments (where the control is synthesized) that involve panel data (observations for different customers over time).

One potential shortcoming of the fixed effects modeling approach implemented here is that its load impact estimates are not readily applied to circumstances other than those of this pilot. In particular, they are tied to the prices employed and therefore cannot be directly applied to situations in which a different price inducement is offered.

In contrast, an electricity demand model imposes constraints in the estimation that comport with economic theory and produce an estimate of a price elasticity. The load impact is normalized for price so that impact prediction is applicable under other nominal levels of price: the estimated impact varies as the price varies, which is consistent with movements along a demand curve so non-price influences are constant.[20]

The Constant Elasticity of Substitution (CES) demand model estimates the elasticity of substitution (EOS). EOS is defined as the percentage change in the quantity ratio (peak to off-peak energy usage) divided by the percentage change in the inverse price ratio (off-peak to peak price). It characterizes how customers shift loads among hours (from high to low priced hours) in response to price changes. Positive EOS estimates suggest that usage is shifted from higher-priced to lower-priced periods, which is consistent with demand theory.[21]

As with the hourly fixed effects model described earlier, the CES model is estimated with customer-specific fixed effects and a separate model is estimated for each pair-wise combination of treatment and control groups. Only non-

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[20] See EPRI 2013 for a discussion of how electricity demand models are formulated and interpreted.

[21] Additional demand model details are provided in Appendix A.

holiday weekdays during the months of June through August are included in each model. We account for first-order serial correlation by estimating the CES fixed-effects model with AR (1) disturbances.

The CES regression model is specified as follows:

$$\ln(kWh_{t,c}^{P} / kWh_{t,c}^{OP}) = \alpha + \sigma \times \ln(P_t^{OP} / P_t^{P}) + \beta^{THI} \times (THI_t^{P} - THI_t^{OP}) + \beta^{THI\_Trt} \times (THI_t^{P} - THI_t^{OP}) \times Treat_c + \beta^{Evt} \times Event_t + v_c + e_t$$

Where:

$kWh^{P}_{t,c}$ is the average hourly usage for customer c on day t during the peak hours, which is 2:00 to 6:00 p.m. for 4-hour utility-controlled PCT customers, and 1:00 to 7:00 p.m. for the 6-hour event treatment;

$kWh^{O}_{t,c}$ is the average hourly usage for customer c on day t during the off-peak hours;

P^{P}_{t} is the average electricity price (\$/kWh) during the peak hours of day t;

P^{O}_{t} is the average electricity price (\$/kWh) during the off-peak hours of day t[22];

σ is the estimate of EOS;

The β's are estimated parameters;

$Event_t$ is an indicator variable that equals one if day t is an event day and zero otherwise;

THI^{P}_{t} equals average hourly THI during the peak hours of day t;

THI^{O}_{t} equals average hourly THI during the off-peak hours of day t;

v_c is the customer-specific fixed effect; and

e_t is the error term.

In this analysis, the term peak period is synonymous with event hours (the 4 or 6 hours in which events are declared), and off peak is all other hours of the day. That is, the model is designed to estimate the extent to which customers shift load from event to non-event hours during PTR event days, which is represented by the estimate of σ (the coefficient on the log inverse price ratio variable). In the absence of the PTR incentive, the retail price is constant during the day.

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[22] The non-event price is equal to \$0.093248 = \$0.02951 + \$0.001747 + \$0.061991. The peak price on event days is equal to \$0.493248 = \$0.40 (PRT incentive paid for reduced) + \$0.093248 (avoided payment under the tariff for load reduced) for PTR treatment customers.

Therefore, on these days, the log inverse price ratio ($ln\ (P^{O}_{t}/P^{P}_{t})$) is equal to zero. Because the control group customers are not exposed to any PTR event days (and hence their price never varies), they do not factor into the estimation of the elasticity of substitution (σ).[23] The $Event_t$ variable is included in order to control for differences in event-day usage that are not explained by price or weather conditions. This variable is applied to both treatment and control group customers, and it ensures that σ represents the event-day treatment effect for PTR customers.

The estimated elasticity of substitution for each study year is provided in Figure 4-14. Elasticity estimates are positive and significant in all three study years, and decline each year. The 2014 estimates are 40-50 percent lower than those of 2012.[24]

Elasticity of Substitution				
	PCT Customer-4hr (B1)	PCT Utility-4hr (B2)	PCT Utility-6hr (C2)	IHD-4hr (B3)
2012	0.094++	0.299++	0.275++	0.087++
2013	0.077++	0.251++	0.228++	0.059++
2014	0.046++	0.241++	0.219++	0.050++

Figure 4-14
Elasticity of Substitution Estimates for Each Treatment for Each Study Year

Utility-controlled PCT elasticities are 3 to 5 times higher than elasticities for customer-controlled PCT and IHD treatments, in all years.

Of particular interest is that the CES model estimates a statistically significant response for B1 (customer-controlled PCT with PTR) and B3 (IHD combined with PTR) customers in 2014, while the fixed effects model indicated that the estimated impact for those treatments was not statistically significantly different from zero.

Note that the two models (hourly fixed effects and CES) estimate the effect of PTR on different usage-based outcomes. The hourly fixed effects models estimate load changes in each hour, while the CES model estimates the change in the peak to off-peak usage ratio. The estimates presented here suggest that for some cells (B1and B3), the aggregate change in the usage ratio may be easier to

[23] The inclusion of data for which the log inverse price ratio is zero is intended to help the model estimate the effect of weather on the usage ratio, which should in turn improve the estimate of σ, which is the primary objective of the model.

[24] This formulation follows the conventional characterization that employs the inverse price ratio – the quantity ratio is defined as the peak over non-peak usage and the price ratio as the off-peak price over the peak price. The same nominal value estimate of EOS results when the price ratio is not inverted, but the expected sign is negative, as reported in some studies.

identify than the change in usage in each hour. However, the two methods are in agreement that there was much greater demand response for utility-controlled PCT customers compared to the other treatment groups.

Summary

Price response, as measured by the elasticity of substitution, varied considerably across treatments, less so over the three-year study period within treatments. The elasticity for utility-controlled PCT participants dropped off about 20 percent from 2012 to 2014, most of that coming in 2013. Treatments B1 and B3 (customer-controlled PCT) and (IHD), showed larger declines in event response from the first to third year of the study, 51 percent and 42 percent, respectively.

One reason postulated for the drop in event response is that 2013 and 2014 were relatively cooler; in 2014 considerably so. That would reduce the need for AC because the ambient temperature is lower and heat buildup is reduced. Price elasticity measures movement along a demand curve for electricity as price changes. However, the relative price that participants faced was constant over the study period. The standard retail rate (applicable except in events) was about \$0.12/kWh and the PTR payment curtailments remained at \$0.40 /kWh. Therefore, one would expect that estimated price elasticity would remain constant unless there was a fundamental change in behavior (the utility of electricity to the household) that caused a shift in the demand curve, and hence equilibrium at a different level of usage for the \$0.40 curtailment incentive.

In the case of B1, participants had to take an affirmative action to reduce usage, by raising the PCT setting or reducing non-AC electricity use. They may have been willing experimental subjects the first year. Those that joined that chose to control their PCT, as opposed to a utility-controlled PCT, indicated that they preferred making their own decisions about event compliance.[25] The fact that they agreed to participate in the pilot suggests that they had some expectation of being able to reduce load during events and realize payments. Using the PCT to initiate a temperature setting rise during events may have been the motivator. Either pursuing self-interest, or seeking to act as they thought they were supposed to (Hawthorne effect), or a combination may explain the substantial response in 2012.

In subsequent years, they had a better understanding of the relationship between what they do and what they are paid. In 2012, PTR payments were made after the summer event season. Some, or many, may have concluded that the discomfort was not worth the financial reward they realized, in effect readjusting their demand curve toward being more inelastic and hence less price responsive.

[25] FirstEnergy customers with central AC were solicited to participate in the study with the offer of a PCT and then were offered their choice of utility control or customer control of the PCT during events.

The IHD participants had no central AC, so to respond they had to turn off other devices, which in some cases may have included a window AC unit, and in many cases fans and lighting were the primary recourse. Turning off these devices requires an affirmative decision by the occupant to elect discomfort to realize a payment. As with B1, the first year's response may have been motivated more by the desire to act as expected than the amount of the financial reward paid at the end of the summer. Likewise, the customer incentive payments, which in many cases may have been under $5 (for all 15 events), may have been too small to induce response in subsequent years.[26]

The results for the utility-control PCT requires a different interpretation. Price response dropped off much less over the study period (about 20%). There was no appreciable increase in event overrides. These participants displayed a resiliency that suggests the lower response in 2013 and 2014 corresponds to the lower AC load of the premise, and not a change in behavior.

[26] In 2012, the estimated event reduction for B1 and B3 was 0.89 and 0.74 kWh reduced per event. That results in $5.35 and $4.42 payment for the summer (15 events). In contrast, B2 and C2 responders on average received four to five times as much, $20.28 and $27.68, respectively.

Section 5: Summary

FirstEnergy's CBS addressed issues that can assist in the development of an effective and efficient portfolio of demand response options. Its intent was to advance the understanding of how residential customers respond to incentives to reduce loads during summer days when doing so provides system and societal net benefits.

The CBS focused on residential customers to provide direction to the development of ways to use their discretionary electricity loads as a system resource. It utilized the capabilities of AMI to record hourly premise loads and as a means of conveying instructions to PCTs and IHDs. The commitment to a three-year experiment provided insights into seasonal and year-to-year event response behavior, which distinguishes the research from many of the other DOE sponsored CBS experiments and plots.

The CBS employed a peak-time rebate (PTR) program structure, implemented through an experimental design, to:

- Test side-by-side direct utility control of a PCT during PTR events with allowing the customer to decide how to respond to the PTR offer;
- Provide a paired-comparison of customer acceptance of and response to a 4-hour event versus a 6-hour event;
- Estimate PTR response by customers without central air but provided with an in-home display; and
- Quantify and characterize PTR response persistence from two perspectives: how event response changes over the course of a season, and how it changes from year to year.

The key findings, associated with individual treatments or other influences, are as follows.

Treatment Effects: Event-hour Load Changes

- The per-hour usage reductions for the 4-hour and 6-hour utility-controlled PCT treatments) were very similar, but more kWh were reduced over the longer event. This is an encouraging result since the length of an event is important from a supply perspective. Longer events help the utility with its event dispatch decisions given that events are declared a day ahead and the daily load peak is difficult to assign confidently to a short time window.

- Even in their best year (2012), event reductions for the customer-controlled PCT and IHD treatment groups were 75 percent lower than those of the utility-controlled PCT groups. Why this is the case is discussed below. While it is tempting to use this as compelling evidence for implementing direct load control, the relative costs must be taken into account before final judgment is passed.

If customers purchase controllable thermostats for their own benefit, greater comfort at a lower cost that creates a stock of potential resources for a PTR program whereby the customer controls event action. They may not be inclined to turn over that device to their utility (or a market agent), but are willing to participate on a self-selecting basis for each event. Even with a lower level of load reduction (compared to utility control), the net cost of the resource provided may be lower because the utility does not purchase the thermostat, it just leases it as needed via the PTR payment.

The advent of smart thermostats (which can be controlled remotely via a phone or other customer-controlled device) may improve event performance over what this study reports. Being able to reduce load remotely may increase response. However, that ease of control may increase the rate of overrides invoked at the commencement of the event and snap-back at the end.

- These results add to the body of research findings that PTR can be an effective means of reducing residential electricity usage under terms that may result in high value to the system and society. As discussed below, the falloff in performance over the study, which was substantial for some treatments, suggests that PTR is best suited to mitigate episodic supply shortage situations.

Snap Back

- Snap back is evident in the utility-controlled PCT treatments, extending 4 to 6 hours beyond the end of the event when the PCT setting reverted to its programmed level. This reflects the requirements to expunge heat buildup in the premise. However, the PCT resumed its programmed setting when the higher setting was reached (usually after 1-2 hours), so some of the recovery AC is supplied prior to the end of the event.
- The long snap back period might reflect an anomaly of human behavior. When feeling extreme discomfort, there is a tendency to set the thermostat even higher than it otherwise would be (to get back to normal) thinking that somehow that will make it more comfortable. A study of the thermal properties of premises and of consumers' demand for comfort is required to explain snap back. Doing so is important to the design of programs so that the result is not just a shift of the system peak load to another time.

Total Event-day kWh Usage

- Total usage on event days was lower than that of a typical hot day, despite the snap back load additions. This is especially the case for the most responsive treatment groups B2 and C2: utility-controlled PCT with a 4-hour and 6-hour event duration, respectively.

- The low override rate suggests that participants in the B2 and C2 (averaging 9-11% per event except for 2014, where the B2 average event override was 19%) treatments are passive compliers. They allow the utility to adjust the AC at the event's commencement and allow that to stay in effect over the event. They do not use the day-ahead notice of the event to precool, although they may overcool after the event.

Persistence

Persistence Over the Three-Year Study Period

- Study period persistence degraded substantially for the two treatments that require an affirmative action by the customer to reduce usage, B1 and B3. In 2014, the event impact was very small or nil for both.
- That was not the case for the two utility-controlled PCT treatments, B2 and C2. They exhibited some decline in event performance in 2013 but that response was stabilized in 2014 at about 75% of the 2012 event level.

Persistence Over a Season's Events

- All of the PCT treatment groups (customers with central AC) showed some evidence of reduced response as the summer season wore on. However, the load impacts for the utility-controlled treatments (B2 and C2) remained comparatively high during the year (relative to the other two treatment groups).
- Persistence over consecutive event days was high.
  - There were six instances of events on consecutive days; four for two consecutive days, one for three consecutive days, and one for four consecutive days.
- Treatments B2 and C2 exhibited robust persistence on most cases (Figure 4-1 and 4-2).
  - On the two consecutive day events, load impacts varied 10-12 percent from the mean level of all days.
  - On the three consecutive two-day events, load impacts varied by less than 10 percent from the mean level of all days.
  - On the four consecutive day events, load impacts varied by 10 to 20 percent from the mean level of all days.
- Consecutive-day performance for treatment B1 and B3 was also robust in 2012, but at a lower average rate.

Persistence Of Subscription

- The number of customers that subscribed to and participated in PTR treatments in 2012 and were still enrolled in 2014 was 97%, 90%, 88%, and 95% for treatments B1, B2, C2, and B3, respectively.

Elasticities of Substitution (EOS) that Measure the Relative Impact of the Inducement on Event Usage

- Estimated 2012 EOS values ranged from 0.09 (B3 IHD) to 0.30 (B2 utility-dispatched PCT).
- All treatment EOSs declined in 2013 and 2014. Since the event load change inducement remained the same ($0.40/kWh), cooler weather (in 2013 and 2014) might have caused a shift in the demand for AC so that customers were more inelastic and less inclined to reduce loads.
- In 2014, the B3 EOS was half of that of 2012. The B2 and C2 EOS was about 20% lower.
- The higher values comport with substitution effects reported in the recently completed DOE-sponsored CBS projects (EPRI 1025856).

This study contributed to understanding the impacts and nuances of employing residential loads as a system resource using a PTR program structure. It deepens considerably our understanding of what level of response to expect, how that response evolves over time, and the influence of PCT and IHD technology. The load impact findings have applicability to many other customer and market circumstances owing to the rigor employed in the study design and the extensive and diverse modeling methods employed.

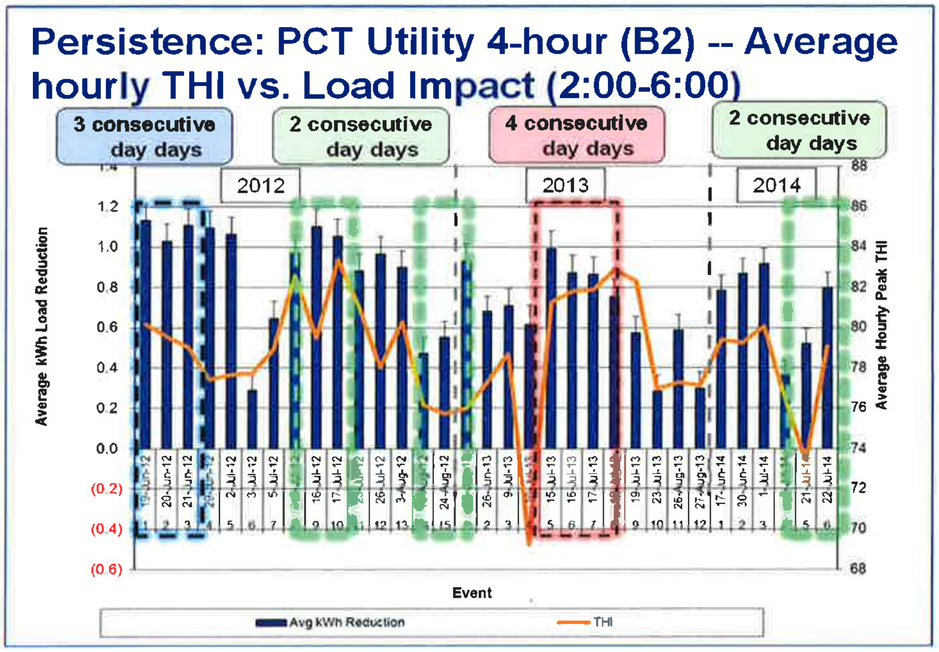

Figure 5-1
Consecutive Day Event Performance – Treatment B2

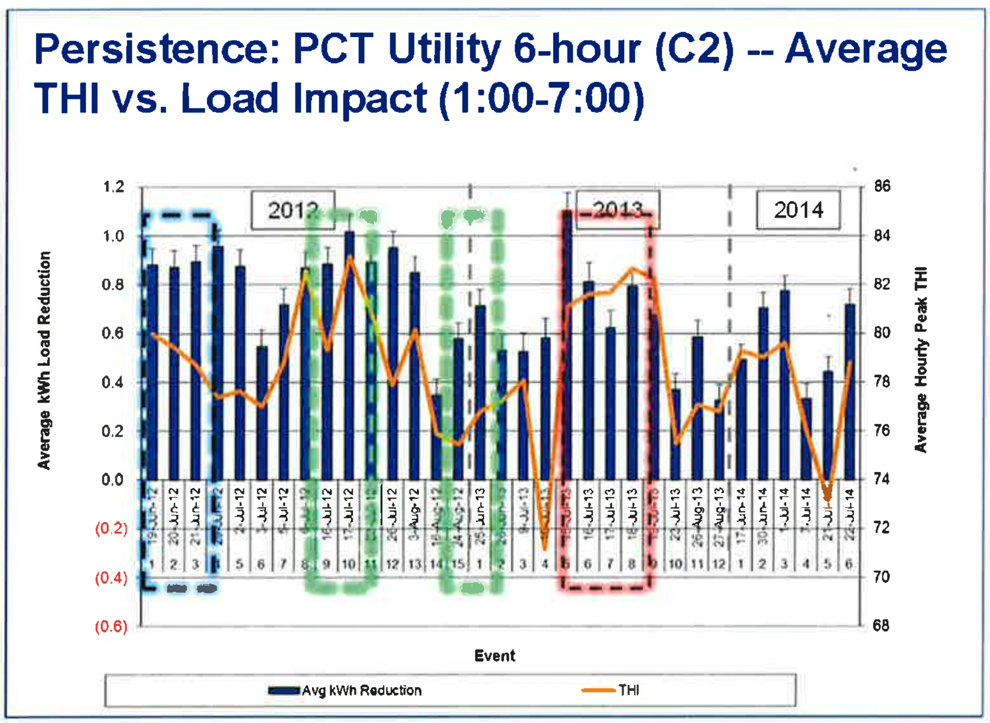

Figure 5-2
Consecutive Day Event Performance – Treatment C2

Appendix A: Detailed Information

This appendix provides detailed information to reinforce the discussion in the main presentation, focused on the following topics:

- Detailed Participant Data
- CES Demand Model Explanation
- CES Demand Model Results
- Persistence: 2012 vs. 2013 Load Impacts
- Persistence: Opt-out Behavior by Event

Full detail of the experimental design and all impact methods employed is available in the Phase 1 Preliminary report.[27]

Detailed Participation Data

As discussed in the body of the report, an assessment of data available for the three-year analysis indicated fewer participants in 2013 compared to 2012 and 2014. Figure A-1 compares the data sets for 2012 and 2013 to characterize participation attrition (less than 5%) from 2012 to 2013. More than twice as many customers were excluded from the analysis in 2013 because of the number of zero hourly values associated with data collection issues.

[27] *FirstEnergy's Consumer Behavior Study: Preliminary Evaluation for 2012*. EPRI. Palo Alto, CA: 2012. 3002001870.

2012			
Cell	# Enrolled (Summer 2012)	# Excluded for Share of Zeroes	# Included in Models
PCT-Control Group (A1/2)	250	9	241
PCT Customer-4hr (B1)	91	3	88
PCT Utility-4hr (B2)	172	3	169
PCT Utility-6hr (C2)	170	4	166
IHD-Control Group (A3)	200	20	180
IHD-4hr (B3)	93	3	90
Total	976	42	934

2013				
Cell	# Enrolled (@ first 2013 evt)	# Excluded for Share of Zeroes	# Included in Models	# Complete 2013 Data
PCT-Control Group (A1/2)	250	17	233	233
PCT Customer-4hr (B1)	88	8	80	78
PCT Utility-4hr (B2)	167	15	152	105
PCT Utility-6hr (C2)	163	14	149	83
IHD-Control Group (A3)	199	33	166	166
IHD-4hr (B3)	89	8	81	81
Total	956	95	861	746

2014				
Cell	# Enrolled (@ first 2014 evt)	# Excluded for Share of Zeroes	# Included in Models	# Complete 2014 Data
PCT-Control Group (A1/2)	248	5	243	243
PCT Customer-4hr (B1)	86	2	84	84
PCT Utility-4hr (B2)	154	3	151	151
PCT Utility-6hr (C2)	149	4	145	144
IHD-Control Group (A3)	200	18	182	182
IHD-4hr (B3)	88	7	81	81
Total	925	39	886	885

Figure A-1
CBS Participation by Treatment and Study Year

Treatments B2 and C2 are the most effected by incomplete time series, sometimes on event days, which results in different customer mixes during some events (the data is imbalanced). Because of our focus on fixed effects, we did not exclude customers for missing data, which was accounted for in the estimation specification.

Usage is lower across the board in 2013, treatment and control groups. Hence, there is less load available to be reduced in 2013, which as discussed in the text, supports the lower model estimate of treatment effects in 2013.

2012				
Cell	Average Non-Holiday Non-Event Weekday kWh During:			
	All Hours	Peak Hours (1:00-7:00pm)	Offpeak Hours	P/O Ratio
PCT-Control Group (A1/2)	1.48	1.95	1.32	1.45
PCT Customer-4hr (B1)	1.35	1.76	1.21	1.42
PCT Utility-4hr (B2)	1.41	1.86	1.26	1.45
PCT Utility-6hr (C2)	1.45	1.88	1.30	1.42
IHD-Control Group (A3)	1.15	1.34	1.09	1.23
IHD-4hr (B3)	1.28	1.44	1.22	1.18

2013				
Cell	Average Non-Holiday Non-Event Weekday kWh During:			
	All Hours	Peak Hours (1:00-7:00pm)	Offpeak Hours	P/O Ratio
PCT-Control Group (A1/2)	1.27	1.53	1.13	1.36
PCT Customer-4hr (B1)	1.20	1.44	1.08	1.33
PCT Utility-4hr (B2)	1.20	1.46	1.08	1.36
PCT Utility-6hr (C2)	1.24	1.48	1.11	1.33
IHD-Control Group (A3)	1.08	1.19	1.01	1.18
IHD-4hr (B3)	1.23	1.35	1.15	1.18

2014				
Cell	Average Non-Holiday Non-Event Weekday kWh During:			
	All Hours	Peak Hours (1:00-7:00pm)	Offpeak Hours	P/O Ratio
PCT-Control Group (A1/2)	1.27	1.63	1.15	1.42
PCT Customer-4hr (B1)	1.18	1.48	1.08	1.37
PCT Utility-4hr (B2)	1.25	1.59	1.14	1.39
PCT Utility-6hr (C2)	1.31	1.63	1.20	1.35
IHD-Control Group (A3)	1.11	1.26	1.05	1.20
IHD-4hr (B3)	1.24	1.40	1.19	1.18

Figure A-2
CBS Average Peak (Event Hours) and Off-Peak kWh Usage by Treatment and Study

Models of Treatment Effects

The Role of a Fixed Model

A fixed effect model assumes that that there are factors that differ among participants, different from the treatments, but they are constant (fixed) over the course of the experiment. Therefore, their effects are captured in a regression as a constant term and the parameters on treatment and conditioning variables represent the marginal effect of changes in them.

Fixed effects models test load impacts in the context of a specific behavioral characterizations. Models have their provenance in statistical theory.[28] They provide a statistical test of whether measured impacts differ from the control. To be employed they require defining a metric (i.e., average event load). The estimated parameter is interpreted as the treatment effect. In the instant application, measuring how the treatment effected kWh usage.

Fixed effects models are very general in their characterization of behavior, in this study electricity usage. They do not necessarily comport with any overarching characterization of consumer behavior. None the less, they are widely used because the interpretation of the estimated impact parameters is generally consistent with a formal behavior model.

A fixed effect model is an element of most CBS analysis because it provides structural insights into treatment effects.[29] However, the application of the results has limited extensibility. Load impacts estimates (change in kWh during the treatment) among pilots are not directly comparable unless every aspect of the pilot is the same. Since few pilots use the same nominal level of price to induce load changes, and employ different enabling technologies, the estimated effects are not readily applicable to other applications that employ different treatments. A structural-derived demand model allows for extending the results to other circumstances.

The Role of a Demand Model

An electricity demand model begins by defining a structure for consumption (electricity usage) that comports with a few fundamental tenants of behavior: consumer seek to maximize their own welfare, and they do so in an orderly and logical way through tradeoffs among alternative goods and services, given available resources (income for consumer demand), and using relative prices.

The conceptual model has an empirical formulation that allows for estimating the key drivers to observed behavior. Behavior is encoded as price elasticity, a price normalized measure of impact of treatment effects. Comparison of elasticities using different price levels are meaningful using judgment as to how wide a range of prices consistent with estimated parameters circumstances.[30]

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[28] Wooldridge, J.M. 2010. Econometric Analyses of Cross Section Panel Data. MIT Press.

[29] *Quantifying the Impacts of Time-Based Rates, Enabling Technology, and Other Treatments in Consumer Behavior Studies: Protocols and Guidelines.* EPRI, Palo Alto, CA. 2013. 3002000282.

[30] Substitution price elasticities measure the effect price difference across time periods. In this study, it measures shifts between event periods and all other event day hours. Price ratios that are substantially larger than those used in the experiment (in this study a ratio of about 4:1) may not be consistent with the estimated model parameters because at some point the nominal event (peak) price is so high that other factors intervene and cause a shift in the demand curve. For example, an event price for $2.00/kWh that has been used in some peak time rebate (PTR) pilots might cause some customers to invest in equipment specifically to be able to response, like energy efficiency measures or load control devices. Doing so results in a shift in the demand curve that results in a larger load change during events.

CES Model Estimates 2012 and 2013

Estimates for 2014 are provided in the report body, comparing them summarily to those of for 2012 and 2103. The estimated CES parameters for 2012 and 2103 are provided below. Two model specifications are reported: log-inverse price ratio and the same price specification but with the THI ratio added.

In both models, the substitution price ratio effects are:

- Positive and significant for all treatments
- About four times larger for the treatments (B2 and C2) that involved the utility raising the thermostat 3 degrees on commence of the event and then removing the control and the end of the event compared to that of:
  - Customer control (B1) – the customer being responsible for making any thermostat adjustment during events (declared and notified to participants the day ahead)
  - The customer control with the availability of an in-home display (IHD) (B3)
  - The B3 treatment combines the $.40/kWh curtailment incentive and the IHD- a joint price and technology treatment
- The near equivalence of the elasticity estimates in each year for B1 and B3 (5-10% higher) suggests that the IHD effect was very small.
- The near equivalence of the B2 and C2 effects, 4-hour and 6-hour events, respectively, suggest that the event length did not affect the price response rate (kW-hour), but the total effect for the 6-hour event was larger.

		2012 Control Group versus:			
		PCT Customer-4hr (B1)	PCT Utility-4hr (B2)	PCT Utility-6hr (C2)	IHD-4hr (B3)
Model 1					
Log Inverse Price Ratio	coef.	0.094++	0.299++	0.275++	0.087++
	std.err.	(0.010)	(0.008)	(0.008)	(0.010)
	p-value	0.000	0.000	0.000	0.000
Model 2					
Log Inverse Price Ratio	coef.	0.174++	0.406++	0.416++	0.138++
	std.err.	(0.025)	(0.018)	(0.017)	(0.024)
	p-value	0.000	0.000	0.000	0.000
(Log Inverse Price Ratio) * (Peak THI-Offpeak THI)	coef.	-0.017++	-0.023++	-0.029++	-0.011+
	std.err.	(0.005)	(0.004)	(0.003)	(0.005)
	p-value	0.001	0.000	0.000	0.019
++p<0.01, +p<0.05					

Figure A-3
CES Demand Model Estimates for 2012

As a result, Model 1 was used for all estimates of impacts.

		2013 Control Group versus: PCT Customer-4hr (B1)	PCT Utility-4hr (B2)	PCT Utility-6hr (C2)	IHD-4hr (B3)
Model 1					
	coef.	0.077++	0.251++	0.228++	0.059++
Log Inverse Price Ratio	std.err.	(0.013)	(0.010)	(0.010)	(0.013)
	p-value	0.000	0.000	0.000	0.000
Model 2					
	coef.	0.068++	0.267++	0.250++	0.046+
Log Inverse Price Ratio	std.err.	(0.018)	(0.015)	(0.018)	(0.018)
	p-value	0.000	0.000	0.000	0.012
	coef.	0.003	-0.004	-0.005	0.004
(Log Inverse Price Ratio) * (Peak THI-Offpeak THI)	std.err.	(0.004)	(0.003)	(0.004)	(0.004)
	p-value	0.486	0.140	0.149	0.336

Figure A-4
CES Demand Model Estimates for 2013

Persistence of Treatment Effects

Section 4 of the report compares estimated effects of 2012-2013 with those of 2014. Figures A-5 through A-7 contain detailed estimates of kWh load impacts, percent load impacts, and event participation, respectively, across all three years.

	2012 Control Group versus			
Hour	PCT Customer-4hr (B1)	PCT Utility-4hr (B2)	PCT Utility-6hr (C2)	IHD-4hr (B3)
1	0.100++	0.026	0.05	0.026
2	0.031	0.02	0.049+	-0.008
3	0.021	0.029	0.039+	-0.008
4	0.025	0.032	0.034+	-0.004
5	0.011	0.012	-0.002	-0.011
6	0.028	-0.002	0.026	-0.038
7	0.016	-0.002	0.031	0.023
8	-0.053	0.003	0.036	0.032
9	-0.076+	-0.004	-0.034	-0.059
10	-0.084+	0.031	0.006	0.011
11	-0.126++	-0.018	-0.005	0.022
12	-0.133++	-0.011	0.086+	0.047
13	-0.115+	0.025	0.087+	0.046
14	-0.110+	0.099+	-1.077++	-0.034
15	-0.173++	-1.034++	-1.066++	-0.164++
16	-0.195++	-0.995++	-0.898++	-0.163++
17	-0.263++	-0.793++	-0.687++	-0.216++
18	-0.261++	-0.556++	-0.456++	-0.194++
19	-0.043	0.687++	-0.430++	0.014
20	0.046	0.636++	0.927++	-0.002
21	0.104	0.481++	0.836++	-0.005
22	0.072	0.283++	0.460++	0.068
23	0.023	0.157++	0.171++	0.109++
24	0.068	0.145++	0.101++	0.016
Event Average	-0.223	-0.845	-0.769	-0.184

++ p<0.01, + p<0.05

	2013 Control Group versus			
Hour	PCT Customer-4hr (B1)	PCT Utility-4hr (B2)	PCT Utility-6hr (C2)	IHD-4hr (B3)
1	0.069	0.004	-0.017	0.007
2	0.042	0.01	-0.022	-0.004
3	0.008	0.012	-0.01	0.008
4	0.029	0.015	0.009	0.026
5	0.022	0.023	-0.005	-0.004
6	0.005	0.016	0.01	-0.014
7	0.029	0.027	-0.006	-0.053
8	0.066	0.022	0	0.047
9	-0.001	-0.014	-0.017	0.008
10	0.100+	0.04	0.071	0.005
11	-0.007	0.033	0.059	0.007
12	-0.019	-0.009	0.02	0.08
13	-0.033	0.013	0.014	0.122+
14	-0.06	0.066	-0.779++	0.053
15	-0.089	-0.720++	-0.799++	0.01
16	-0.149+	-0.831++	-0.748++	0.017
17	-0.032	-0.583++	-0.576++	-0.018
18	-0.096	-0.473++	-0.439++	-0.052
19	0.015	0.566++	-0.342++	0.042
20	0.037	0.461++	0.925++	0.04
21	0.064	0.276++	0.618++	0.096
22	0.122+	0.188++	0.283++	0.007
23	0.093	0.06	0.126++	-0.029
24	0.100+	0.02	0.042	-0.04
Event Average	-0.092	-0.652	-0.614	-0.011

++ p<0.01, + p<0.05

	2014 Control Group versus			
Hour	PCT Customer-4hr (B1)	PCT Utility-4hr (B2)	PCT Utility-6hr (C2)	IHD-4hr (B3)
1	-0.051	-0.007	-0.025	-0.033
2	-0.009	0.006	0.002	-0.007
3	-0.051	-0.015	-0.049	0.002
4	-0.036	-0.028	-0.02	0.006
5	0.008	-0.003	0.015	-0.032
6	0.004	-0.003	0.080++	-0.012
7	-0.027	0.021	0.048	0.014
8	0.007	0.000	0.011	0.031
9	-0.013	-0.02	0.001	0.059
10	0.102+	-0.002	-0.01	0.093
11	0.085	0.061	0.058	0.112
12	0.016	0.054	0.062	0.086
13	0.001	-0.013	0.092	0.032
14	-0.09	-0.089	-0.699++	0.044
15	-0.115	-0.848++	-0.747++	-0.051
16	-0.023	-0.803++	-0.607++	0.033
17	0.012	-0.672++	-0.553++	-0.047
18	0.108	-0.439++	-0.407++	-0.051
19	0.177+	0.549++	-0.331++	-0.016
20	0.042	0.434++	0.666++	-0.037
21	0.045	0.301++	0.554++	0.051
22	0.08	0.126+	0.310++	0.011
23	0.185++	0.129++	0.169++	0.072
24	0.161++	0.041	0.090+	0.042
Event Average	-0.005	-0.691	-0.557	-0.029

++ p<0.01, + p<0.05

Figure A-5
Persistence 2012-2014; Hourly kWh Load Impacts

	2012 Control Group versus			
Hour	PCT Customer-4hr (B1)	PCT Utility-4hr (B2)	PCT Utility-6hr (C2)	IHD-4hr (B3)
1	7%	2%	3%	2%
2	2%	2%	4%	-1%
3	2%	3%	4%	-1%
4	3%	3%	3%	0%
5	1%	1%	0%	-1%
6	3%	0%	2%	-3%
7	1%	0%	2%	2%
8	-4%	0%	2%	2%
9	-5%	0%	-2%	-4%
10	5%	2%	0%	1%
11	-7%	-1%	0%	2%
12	-7%	-1%	4%	3%
13	-5%	1%	4%	3%
14	-5%	4%	-44%	-2%
15	-7%	-40%	-41%	-10%
16	-7%	-36%	-31%	-10%
17	-9%	-26%	-22%	-12%
18	-8%	-17%	-14%	-10%
19	-1%	22%	-13%	1%
20	2%	22%	31%	0%
21	4%	18%	30%	0%
22	3%	10%	17%	4%
23	1%	7%	7%	6%
24	3%	8%	5%	1%
Event Average	-8%	-30%	-28%	-11%

	2013 Control Group versus			
Hour	PCT Customer-4hr (B1)	PCT Utility-4hr (B2)	PCT Utility-6hr (C2)	IHD-4hr (B3)
1	5%	0%	-1%	1%
2	3%	1%	-2%	0%
3	1%	1%	-1%	1%
4	3%	1%	1%	3%
5	2%	2%	-1%	0%
6	0%	2%	1%	-1%
7	2%	2%	0%	-4%
8	5%	2%	0%	3%
9	0%	-1%	-1%	1%
10	7%	3%	4%	0%
11	0%	2%	3%	0%
12	-1%	0%	1%	5%
13	-2%	1%	1%	8%
14	-3%	3%	-34%	3%
15	-4%	-30%	-33%	1%
16	-6%	-31%	-28%	1%
17	-1%	-21%	-20%	-1%
18	-3%	-16%	-15%	-3%
19	1%	20%	-12%	2%
20	1%	17%	36%	2%
21	2%	11%	24%	5%
22	5%	8%	11%	0%
23	4%	3%	6%	-2%
24	5%	1%	2%	-3%
Event Average	-4%	-25%	-24%	-1%

	2014 Control Group versus			
Hour	PCT Customer-4hr (B1)	PCT Utility-4hr (B2)	PCT Utility-6hr (C2)	IHD-4hr (B3)
1	-4%	-1%	-2%	-3%
2	-1%	1%	0%	-1%
3	-6%	-2%	-5%	0%
4	-4%	-3%	-2%	1%
5	1%	0%	2%	-3%
6	0%	0%	8%	-1%
7	-3%	2%	4%	1%
8	1%	0%	1%	2%
9	-1%	-2%	0%	4%
10	7%	0%	-1%	7%
11	5%	4%	3%	8%
12	1%	3%	3%	6%
13	0%	-1%	4%	2%
14	-4%	-4%	-30%	3%
15	-5%	-36%	-31%	-3%
16	-1%	-32%	-24%	2%
17	0%	-25%	-20%	-3%
18	4%	-15%	-14%	-3%
19	7%	20%	-12%	-1%
20	2%	17%	25%	-2%
21	2%	12%	22%	3%
22	3%	5%	12%	1%
23	9%	6%	8%	4%
24	9%	2%	5%	3%
Event Average	0%	-27%	-22%	-2%

Figure A-6
Persistence 2012-2014; Hourly Percent Load Impacts

		2012 PCT Utility-4hr (B2)		PCT Utility-6hr (C2)	
Event		# Overrides	% Customers Enrolled	# Overrides	% Customers Enrolled
1	19-Jun-12	22	13%	13	8%
2	20-Jun-12	18	10%	15	9%
3	21-Jun-12	12	7%	10	6%
4	29-Jun-12	16	9%	18	11%
5	2-Jul-12	15	9%	11	6%
6	3-Jul-12	14	8%	9	5%
7	5-Jul-12	9	5%	10	6%
8	6-Jul-12	18	10%	17	10%
9	16-Jul-12	15	9%	10	6%
10	17-Jul-12	12	7%	18	11%
11	23-Jul-12	20	12%	17	10%
12	26-Jul-12	19	11%	16	9%
13	3-Aug-12	19	11%	15	9%
14	16-Aug-12	16	9%	7	4%
15	24-Aug-12	17	10%	10	6%
Event Average		16	9%	13	8%

		2013 PCT Utility-4hr (B2)		PCT Utility-6hr (C2)	
Event		# Overrides	% Customers Enrolled	# Overrides	% Customers Enrolled
1	25-Jun-13	20	12%	23	14%
2	26-Jun-13	18	11%	20	12%
3	9-Jul-13	10	6%	11	7%
4	10-Jul-13	9	5%	10	6%
5	15-Jul-13	17	10%	14	9%
6	16-Jul-13	20	12%	10	6%
7	17-Jul-13	16	10%	11	7%
8	18-Jul-13	15	9%	18	11%
9	19-Jul-13	22	13%	18	11%
10	23-Jul-13	8	5%	12	8%
11	26-Aug-13	17	11%	20	13%
12	27-Aug-13	18	11%	21	14%
Event Average		16	10%	16	10%

		2014 PCT Utility-4hr (B2)		PCT Utility-6hr (C2)	
Event		# Overrides	% Customers Enrolled	# Overrides	% Customers Enrolled
1	17-Jun-14	18	12%	29	19%
2	30-Jun-14	16	10%	28	19%
3	1-Jul-14	21	14%	30	20%
4	7-Jul-14	16	10%	27	18%
5	21-Jul-14	13	8%	23	15%
6	22-Jul-14	21	14%	29	19%
Event Average		18	11%	28	19%

Figure A-7
Persistence 2012-2014; Event Participation/Override Behavior

Appendix B: Fixed Effects Model Estimates for 2012, 2013, and 2014

	Control Group versus:			
Hour	PCT Customer-4 hr (B1)	PCT Utility-4 hr (B2)	PCT Utility-6 hr (C2)	IHD-4 hr (B3)
1	0.100++	0.026	0.05	0.026
2	0.031	0.02	0.049+	-0.008
3	0.021	0.029	0.039+	-0.008
4	0.025	0.032	0.034+	-0.004
5	0.011	0.012	-0.002	-0.011
6	0.028	-0.002	0.026	-0.038
7	0.016	-0.002	0.031	0.023
8	-0.053	0.003	0.036	0.032
9	-0.076+	-0.004	-0.034	-0.059
10	-0.084+	0.031	0.006	0.011
11	-0.126++	-0.018	-0.005	0.022
12	-0.133++	-0.011	0.086+	0.047
13	-0.115+	0.025	0.087+	0.046
14	-0.110+	0.099+	-1.077++	-0.034
15	-0.173++	-1.034++	-1.066++	-0.164++
16	-0.195++	-0.995++	-0.898++	-0.163++
17	-0.263++	-0.793++	-0.687++	-0.216++
18	-0.261++	-0.556++	-0.456++	-0.194++
19	-0.043	0.687++	-0.430++	0.014
20	0.046	0.636++	0.927++	-0.002
21	0.104	0.481++	0.836++	-0.005
22	0.072	0.283++	0.460++	0.068
23	0.023	0.157++	0.171++	0.109++
24	0.068	0.145++	0.101++	0.016
Event Average	-0.223	-0.845	-0.769	-0.184

++ $p<0.01$, + $p<0.05$

Figure B-1
Fixed Effects Estimates for 2012

- B2 and C2 have statistically significant load reductions in all event hours, four ands six hours, respectively
- B2 and C2 also both show load increases in post-event hours .
- The net impact of statistically significant event and post-event hour estimates are -0.57 kWh for B2 and -0.53 kWh for C2.
  - i.e. Even with a shorter event window and the same number of snapback-hours, cell B2 produced more net load reduction.
- B1 has estimated load reductions in all event hours,

2013

Control Group versus:

Hour	PCT Customer-4hr (B1)	PCT Utility-4hr (B2)	PCT Utility-6hr (C2)	IHD-4hr (B3)
12	-0.019	-0.009	0.02	0.08
13	-0.033	0.013	0.014	0.122+
14	-0.06	0.066	-0.779++	0.053
15	-0.089	-0.720++	-0.799++	0.01
16	-0.149+	-0.831++	-0.748++	0.017
17	-0.032	-0.583++	-0.576++	-0.018
18	0.096	0.473++	0.430++	-0.052
19	0.015	0.566++	-0.342++	0.042
20	0.037	0.461++	0.925++	0.04
21	0.064	0.276++	0.618++	0.096
22	0.122+	0.188++	0.283++	0.007
23	0.093	0.06	0.126++	-0.029
24	0.100+	0.02	0.042	-0.04
Event Average	-0.092	-0.652	-0.614	-0.011

- B2 and C2 have statistically significant load reductions in all event hours.
- B2 and C2 also both show load increases in post-event hours.
- The net impact of statistically significant event and post-event hour estimates are -0.57 kWh for B2 and -0.53 kWh for C2.
  - i.e. Even with a shorter event window and the same number of snapback-hours, cell B2 produced more net load reduction.
- B1 has estimated load reductions in all event hours, but only hour-ending 16 is statistically significant.

Figure B-2
Fixed Effects Estimates for 2013

2014

Control Group versus:

Hour	PCT Customer-4hr (B1)	PCT Utility-4hr (B2)	PCT Utility-6hr (C2)	IHD-4hr (B3)
12	0.016	0.054	0.062	0.086
13	0.001	-0.013	0.092	0.032
14	-0.09	-0.089	-0.699++	0.044
15	-0.115	-0.848++	-0.747++	-0.051
16	-0.023	-0.803++	-0.607++	0.033
17	0.012	-0.672++	-0.553++	-0.047
18	0.108	-0.439++	-0.407++	-0.051
19	0.177+	0.549++	-0.331++	-0.016
20	0.042	0.434++	0.666++	-0.037
21	0.045	0.301++	0.554++	0.051
22	0.08	0.126+	0.310++	0.011
23	0.185++	0.129++	0.169++	0.072
24	0.161++	0.041	0.090+	0.042
Event Average	-0.005	-0.691	-0.557	-0.029

Values in the table represent hourly event load impacts measured in kWh.

++ p<0.01, + p<0.05

- B2 and C2 have statistically significant load reductions in all event hours.
- B2 and C2 also both show load increases in post-event hours.
- The net impact of statistically significant event and post-event hour estimates are -1.22 kWh for B2 and -1.56 kWh for C2.
- B1 and B3 have mixed positive and negative estimated load impacts during event hours but none are statistically significant.

Figure B-3
Fixed Effects Estimates for 2014

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