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VIA ELECTRONIC FILING
Aida Camacho-Welch, Secretary
New Jersey Board of Public Utilities
44 South Clinton Avenue, 9th Floor
P.O. Box 350
Trenton, New Jersey 08625-0350

RE: I/M/O Natural Gas Commodity and Delivery Capacities in the State Of New Jersey – Investigation of the Current and Mid-Term Future Supply and Demand (BPU Docket No. GO20010033)

Dear Secretary Camacho-Welch,

On behalf of our client Google, LLC, we submit these comments regarding the BPU's gas capacity investigation. Google, LLC is a multinational technology company and manufacturer of the Nest Learning Thermostat, the Nest Thermostat E, and the Nest Thermostat (2020), three of the leading smart thermostats offered in the United States. Nest thermostats incorporate numerous features that help customers reduce their energy consumption for residential heating and cooling, which can also help utilities and the state of New Jersey accomplish core energy efficiency and peak demand reduction goals.

Comments on Non-Pipe Alternatives Questions for Stakeholders

Question A: How have voluntary peak management demand programs been structured in other jurisdictions or related industries? For example, how much would it cost to purchase and install directly controllable thermostats for all firm heating customers? Would smart meters be required as well? What would be the cost of these? Are there other examples of peak management demand programs, and what best practices can the State implement for these programs?

Google's response:
Smart thermostats are an established and cost-effective solution to deliver peak demand flexibility to gas utilities. There are now clear reference points in the industry where gas utilities have utilized

smart thermostats to deliver peak demand reduction for gas in a similar way to on the electric side. The keys to building effective gas demand response ("DR") programs are: 1) a customer-centric view to program design and incentives; and 2) to leverage the learnings from many years of electric smart thermostat demand response. At its core, the same smart thermostat that is being deployed for energy efficiency and electric demand response can also be utilized for gas demand response, if the right customer incentives and program rules are in place.

Google recommends the following best practices:

- **Design for the residential sector** - Smart thermostats are primarily deployed in single-family and multi-family homes, and occasionally in very small commercial settings. There is gas demand response potential both in single-family and multi-family (apartment) homes.
- **Leverage experience from smart thermostat DR on the electric side** - In the same way that "Non-Pipes Alternatives" lean on best practices from "Non-Wires Alternatives," gas demand response can learn from the deep experience of electric demand response via smart thermostats. The wheel does not need to be recreated. Gas DR programs can be adapted from what has been successful on the electric side. We recommend that New Jersey convene a working group comprised of GDCs, smart thermostat manufacturers (which includes Google Nest), as well as Distributed Energy Resource Management System (DERMS) providers to further discuss best practices in gas DR program design.
- **Consider relevant utility case studies** - There are two examples of gas peak demand management programs that New Jersey can consider in framing a program: Southern California Gas Company ("SoCalGas") and Consolidated Edison Company of New York, Inc. ("Con Edison"). We have included more information about each program below.

SoCalGas was the first smart thermostat gas DR program of its kind in the world when it was launched in 2017 in response to the Aliso Canyon gas constraint in Southern California. The program has been successful in reducing gas capacity constraints. Nexant has led multiple evaluations for this program which found average DR event savings of 0.085-0.113 therms per customer, or roughly 15% savings.[1]

Con Edison proposed the Smart Solutions for Natural Gas Customers Program ("Smart Solutions") in 2017 to address increased demand for natural gas in its service territory and limited pipeline capacity. This innovative, integrated, multi-solution program has successfully decreased gas usage in New York and helped to procure alternative resources to meet customer heating and other thermal needs.[2]

Question B: Consider a program in which smart thermostats controlled directly by the GDC during potential supply disruption were provided to all firm heating customers at no cost to the customer, and the capital cost to the GDC could be included in rate base. Please describe the benefits and consequences of such a program. How should Staff consider the program in terms of cost to provide reliability? Would it be equitable to all customers?

Google's response:

A program in which smart thermostats are provided at no cost to customers in exchange for their participation in a gas DR program with their GDC would provide the greatest impact and widest, most equitable reach to customers. It would also result in the largest possible flexible gas DR resource. There are positive precedents for this exact kind of broad campaign focused on customer adoption, such as:

- New Jersey Natural Gas's Free Thermostat initiative in June 2020 to provide energy and cost savings to customers during the COVID pandemic[3]
- ComEd's Million Thermostat Program[4]

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[1] Nexant's 2017-2018 SoCalGas Demand Response Winter Load Impact Evaluation, available at: http://www.calmac.org/publications/SoCalGas_2018_DR_Evaluation_Report_-_Public_FINAL.pdf; Nexant's 2018-2019 Winter Load Impact Evaluation of SoCalGas Smart Therm Program, available at: http://www.calmac.org/publications/SoCalGas_2019_DR_Evaluation_Report_-_PUBLIC_FINAL.pdf (We have also attached all cited documents to these comments.)

[2] Con Edison Gas Demand Response Pilot Implementation Plan, 2018-2021, available at: https://www.coned.com/-/media/files/coned/documents/save-energy-money/rebates-incentives-tax-credits/smart-usage-rewards/gas-demand-response-implementation-plan.pdf; see also "Consolidated Edison gets approval for natural gas demand response pilot program" [EIA Article]

[3] https://www.njresources.com/news/releases/2020/njng/20-21njnggooglethermostat.aspx

[4] https://smartenergycc.org/wp-content/uploads/2016/09/SGCC-2016-Members-Meeting-Million-Thermostat-Program.pdf

- Ontario's Green Savings Free Thermostat Program[5]

There is also emerging precedent for considering smart thermostats as a regulatory asset through Grid Modernization proceedings around the country. We would advise, however, that smart thermostats not be considered like legacy DLC switches that are controlled directly by a utility (as in AC Cycling programs), but rather as a behind-the-meter, load-reduction device that can be aggregated into a reliable DR resource that is controllable and dispatchable via a GDC's DERMS platform. Con Edison utilized this approach and defined their participation parameters as: *"Customers and/or aggregators are responsible for their participation strategy on gas DR event days. Con Edison will not have direct control of customer appliances, controls, or other equipment."*[6]

Question C: What would be the potential uptake and impact of a "time of use" (TOU) program? For example, if a TOU or other peak demand-management program was offered to customers based on smart thermostats, would an opt-out program have a bigger impact than an opt-in program? If so, what would be the magnitude? Would it be more effective to offer an option to customers to opt in or opt out based on a level of emergency (e.g., yellow, orange, or red) where there would be different price incentives based on the level of the emergency?

Google's response:

AMI meters are not needed to run residential smart thermostat DR programs today. However, the data captured through AMI meters and technology would enable GDCs to perform more granular analysis for load forecasting and dispatch needs across the grid. In the future, with higher penetration of solar and electric vehicles, AMI meters and technology will provide GDCs with the ability to create a more targeted DR dispatch model in high-growth or constrained areas, or during critical peaks. The grid will become more complex over time with the increase of DERs. It will require increasingly automated command-and-control systems to support grid operations and to enhance system planning overall for reliability. AMI meters and supporting technology are foundational elements to support that vision. In addition, for GDCs and third-party suppliers to be

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[5] https://ontariogreensavings.com/free-thermostat/

[6] Con Edison Gas Demand Response Implementation Plan, Page 8 (https://www.coned.com/-/media/files/coned/documents/save-energy-money/rebates-incentives-tax-credits/smart-usage-rewards/gas-demand-response-implementation-plan.pdf)

able to leverage more advanced rate structures to further help shape demand, such as Time of Use, Critical Peak Pricing, Real-Time-Pricing, etc., AMI will be required.

Thank you for the opportunity to provide these comments.

Respectfully submitted,

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Attorneys for Google, LLC

Enclosures

REPORT

SoCalGas Demand Response: 2017/2018 Winter Load Impact Evaluation

August 14, 2018

Prepared for
Southern California Gas Company

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CALMAC ID: SCG0220

Table of Contents

1 Executive Summary

SoCalGas was directed by the California Public Utilities Commission (CPUC) to continue and expand the SoCalGas Thermostat Program in response to the potential need for demand reductions during the 2017-2018 winter and future winters. The Smart Thermostat Program for 2018 was an offering where two vendors (Vendor 1 and Vendor 2) recruited from their installed smart thermostat customer base, and offered incentives for customers to enroll. The program was event-based, meaning that it targeted relatively few hours on days of peak demand. Load reductions were attained on event days from temporary degree setbacks on thermostats, which led to a reduction in demand for heating. All activations took place either between the hours of 5 AM to 9 AM or 5 PM to 9 PM.

Gas load impacts (usage reductions) on event days were estimated by applying the best practices that have been developed for electric Demand Response (DR) program measurement and evaluation in California. As in the annual electric DR evaluations, the SoCalGas Smart Thermostat Program load impact estimates leverage the wide availability of interval data from advanced meters to estimate the usage reductions.

Table 1-1 provides a summary of the 2017-2018 winter SoCalGas Smart Thermostat Program hourly event impacts for each event and for the average morning and evening event by vendor. The average load reduction for a Vendor 1 morning event was 0.031 thm per participant leading to an aggregate reduction of 217.152 thm, or 16.0%. The average load reduction for a Vendor 1 evening event was 0.012 thm, leading to an aggregate reduction of 81.795 thm, or 10.7%. The average load reduction for a Vendor 2 morning event was 0.050 thm, leading to an aggregate reduction of 102.308 thm, or 25.0%. The average load reduction for a Vendor 2 evening event was 0.014 thm, leading to an aggregate reduction of 37.768 thm, or 15.6%. Vendor 2 event impacts were consistently larger than Vendor 1 event impacts, and both vendors saw morning event impacts that were larger than evening event impacts.

Table 1-1: Winter 2017-2018 Load Impact Estimates

Date	Event Window	Vendor 1				Vendor 2				Avg. Event Temp. (°F)
		Number of Participants	Average Impact (thm)	Aggregate Impact (thm)	Impact (%)	Number of Participants	Average Impact (thm)	Aggregate Impact (thm)	Impact (%)	
20-Feb	AM	6,976	0.029	201.36	12.5%	2,029	0.052	105.14	21.2%	44.8
20-Feb	PM	-	-	-	-	2,029	0.031	63.70	22.0%	51.8
21-Feb	AM	6,976	0.032	224.78	15.5%	2,029	0.052	104.96	23.7%	50.2
21-Feb	PM	-	-	-	-	2,029	0.023	46.84	18.0%	53.2
22-Feb	AM	6,976	0.031	214.12	14.1%	2,029	0.048	96.41	21.2%	48.7
22-Feb	PM	-	-	-	-	2,029	0.016	32.47	13.3%	53.5
23-Feb	AM	6,976	0.030	211.73	15.3%	-	-	-	-	48.3
26-Feb	PM	6,976	0.012	85.01	11.4%	2,029	0.017	34.29	16.4%	55.5
27-Feb	AM	6,976	0.031	214.71	16.5%	2,029	0.050	101.86	25.9%	46.8
28-Feb	PM	6,976	0.015	105.33	12.7%	2,029	0.010	20.76	9.6%	54.2
1-Mar	AM	6,976	0.032	222.01	16.4%	2,029	0.058	116.67	28.7%	51.0
1-Mar	PM	6,976	0.008	55.05	8.0%	2,029	0.014	28.55	14.3%	54.7
2-Mar	AM	6,976	0.033	231.36	21.6%	2,029	0.044	88.81	29.1%	52.3
All Events										
Avg.	**AM**	6,976	0.031	217.15	16.0%	2,029	0.050	102.31	25.0%	48.9
Avg.	**PM**	6,976	0.012	81.80	10.7%	2,029	0.019	37.77	15.6%	53.8
Common Events across both vendors										
Avg.	**AM**	6,976	0.031	218.01	16.1%	2,029	0.050	102.31	25.0%	49.0
Avg.	**PM**	6,976	0.012	81.80	10.7%	2,029	0.014	27.87	13.4%	54.8

The SoCalGas Thermostat program is one of the first, if not the first, natural gas based demand response programs in the US. It has proven that smart thermostats can be used to reduce demand for natural gas during targeted periods of time in the morning and evening. However, the thermostat setback strategy was also shown to be important, and can significantly affect the size of the load reductions and the post-event "snap back", as shown by the different vendor performance. The snap back following the event when a customer's preferred temperature settings are restored can be quite significant, and generally erases any net daily therm savings.

From a technical perspective, it's clear the program met the objectives of reducing gas consumption during specific windows of time. However, due to gas usage snap backs in the hours following events, there were no statistically significant net daily therm savings that resulted from this program. Without statistically significant net daily therm savings there is an open question regarding whether the program created value from a reliability or economic perspective. While on the electric grid blackouts can be caused by an immediate supply/demand imbalance, gas supply shortages causing low gas system pressure and deliverability issues are typically a more protracted event due to the slow speed of how gas travels. It's unclear how much of a supply shortage may exist for only a few hours in Southern California. If there aren't supply shortages lasting only a few hours, it's possible that traditional energy efficiency and behavioral conservation based programs, most notably Seasonal Energy Update energy reports, may yield greater savings over longer periods of supply shortage. These interventions have the dual benefit of providing significant gas savings on both DR event days and non-DR days throughout the winter.

2 Overview

SoCalGas was directed by the California Public Utilities Commission (CPUC) to continue and expand the SoCalGas Thermostat Program in response to the potential need for demand reductions during the 2017-2018 winter and future winters. The Smart Thermostat Program for 2018 was an offering where two vendors (Vendor 1 and Vendor 2) recruited from their installed smart thermostat customer base, and offered incentives for customers to enroll. The program was event-based, meaning that it targeted relatively few hours on days of peak demand. Load reductions were attained on event days from temporary degree setbacks on thermostats, which led to a reduction in demand for heating. Further details regarding the implementation of the pilot are contained in Section 2.1.

Gas load impacts on event days were estimated by applying the best practices that have been developed for electric Demand Response (DR) program measurement and evaluation in California. In 2008, the California Public Utilities Commission (CPUC) and joint electric Investor-Owned Utilities (IOUs) developed California's Load Impact Protocols, which required the electric utilities to conduct annual evaluations of all DR programs in the state. As in the annual electric DR evaluations, the SoCalGas Smart Thermostat Program load impact estimates leverage the wide availability of interval data from advanced meters to estimate usage reductions. The program evaluation methodology that uses a matched control group is similar to how most electric DR programs have been evaluated for several years, including Southern California Edison's (SCE's)® Save Power Days (also known as Peak Time Rebate) Program,[1] which is also a smart thermostat program.

Throughout this report, Nexant will define event, program, and load as follows:

- Event – refers to the four-hour period during which SoCalGas adjusted a customer's thermostat in order to reduce heating demand during that period (an "activation"). There can be multiple events in a single day.
- Program – refers to the SoCalGas Smart Thermostat Program, which is a combination of the Vendor 1 Program and the Vendor 2 Program
- Load – refers to customer gas usage, measured in therms (thm)

2.1 Program Design and Implementation

The SoCalGas Smart Thermostat program used the Bring Your Own Thermostat (BYOT) model to recruit existing customers with Vendor 1 and Vendor 2 thermostats into the program by offering up to $75 of incentives. Customers who enrolled in the program received a $50 enrollment incentive, as well as a $25 participation incentive after the winter season for remaining in the program. To recruit customers into the program, SoCalGas promoted the program using social media and radio advertising, and the vendors reached out to customers who had already adopted smart thermostat technologies. SoCalGas additionally sent out bill inserts to customers and had an email campaign for the program. Before the start of the program, customers were told that if an event was called, customer thermostats could be

[1] Nexant. "2017 Load Impact Evaluation of Southern California Edison's Peak Time Rebate Program." April 1, 2018. CALMAC Study ID: SCE0420.

adjusted remotely by SoCalGas by a few degrees, and there would be no “penalty of non-participation” for overriding a smart thermostat during a Natural Gas Conservation event. As shown in Table 2-1, at the end of recruitment, Vendor 1 had a little over 7,000 customers enroll in the Vendor 1 program and Vendor 2 had almost 2,000 customers enroll in the Vendor 2 program, for a total of approximately 9,000 customers enrolled in the SoCalGas Smart Thermostat Program.

Table 2-1: Vendors and Respective Pilot Program Enrollment

Contracted Vendor	Smart Thermostat Program	Enrolled Customers
Vendor 1	Vendor 1 Program	7,132
Vendor 2	Vendor 2 Program	1,842

Table 2-2 provides a summary of eligibility screens that each vendor applied to customers who had agreed to participate. Customers needed to own a thermostat from the respective vendor and needed to be a current SoCalGas residential gas service account holder. Vendor 2 additionally required that participants could not currently be enrolled in the SCE Save Power Days Program or the "SoCalGas Advanced Meter Opt-Out Program".

Table 2-2: Smart Thermostat Program Vendor Eligibility Requirements

Vendor 1 Criteria	Vendor 2 Criteria
Own Vendor 1 Thermostat with an active account	Own Vendor 2 Thermostat with active account
Have a wireless network installed at service address	Have a wireless network installed at service address
Active SoCalGas Account	Active SoCalGas Account
	Not enrolled in SCE Save Power Days
	Installed Advanced Meter at service address
	Natural gas furnace
	Not enrolled in “SoCalGas Meter Opt-Out Program”

Natural Gas Conservation events took place during periods of system constraint by adjusting thermostats to a lower temperature by no more than four degrees. Once the activations came to an end, thermostats were returned to their original set points.[2] All activations took place either between the hours of 5 AM to 9 AM or 5 PM to 9 PM, and customers who participated in the program received a notice at least two hours before the event.[3]

[2] Vendor 1 limits its thermostat adjustment to three degrees. Vendor 1 thermostats additionally will pre-adjust the temperature in the home before the event to maximize comfort. However, in the case of a morning event the thermostat will not pre-adjust the temperature unless the customer has a specific setting enabled. This is to ensure noise comfort for the customer.

[3] With the exception of Vendor 1’s second event in a day, which notifies the customer at the time of the activation.

In May 2018, SoCalGas conducted a focus group in order to evaluate overall customer satisfaction with the DR program. In the focus group, customers did not report any pain points for enrollment in either program, and they found enrollment in the program to be "fast and easy". The focus group also found that both Vendor 1 and Vendor 2 customers were very satisfied with the program, and were likely to recommend the program to a friend and participate in the program again.[4]

2.2 Program Participants

Customers who signed up to participate in the SoCalGas Smart Thermostat Program are inherently different from customers who did not sign up to participate in the program or customers who were not targeted by SoCalGas marketing or thermostat vendors. Before the evaluation, specific customer segments were examined to observe how program participants differed from the overall population. Table 2-3 compares the portion of CARE customers who enrolled in the pilot to the overall population. Program participants were less likely to be CARE customers compared to the general residential population.

Table 2-3: Comparison of Program and Participation CARE Customers

CARE	% of Program Participants	% of SoCalGas Residential Customers
Yes	9%	28%
No	91%	72%
All	100%	100%

Table 2-4 compares the breakout of SoCalGas program participant housing type to the SoCalGas residential customer population. Program participants were more likely to reside in a single family home compared to the general population.

Table 2-4: Comparison of Program and Population Housing Types

Housing Type	% of Program Participants	% of SoCalGas Residential Customers
Single Unit	84%	65%
2 or More Separate Units	2%	3%
2-4 Connected Units	4%	10%
5 or More Connected Units	10%	22%
Mobile Home Park	0%	0%
All	100%	100%

[4] From Vendor 1 program and Vendor 2 progam Focus Group Report.

Figure 2-1 shows a heat map of the locations of pilot participants throughout the SoCalGas service territory. The largest concentrations of customers are in the LA Basin and Orange County areas. The next largest concentration is in the Riverside, Palm Springs and Bakersfield areas.

Figure 2-1: Heat Map of Pilot Participant Location

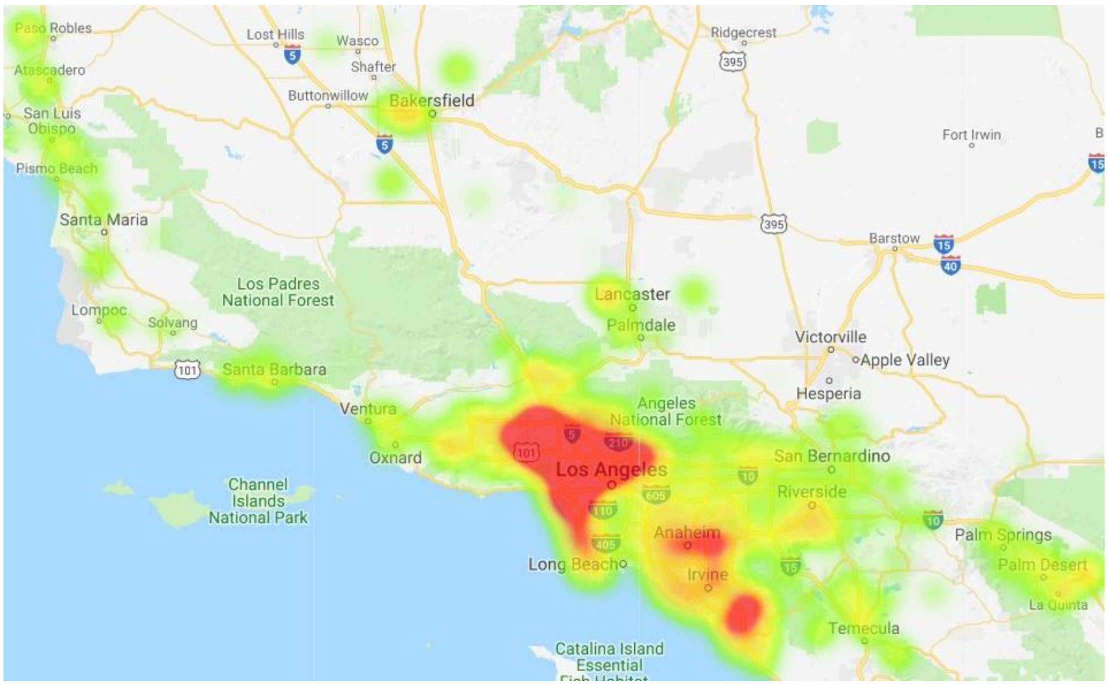
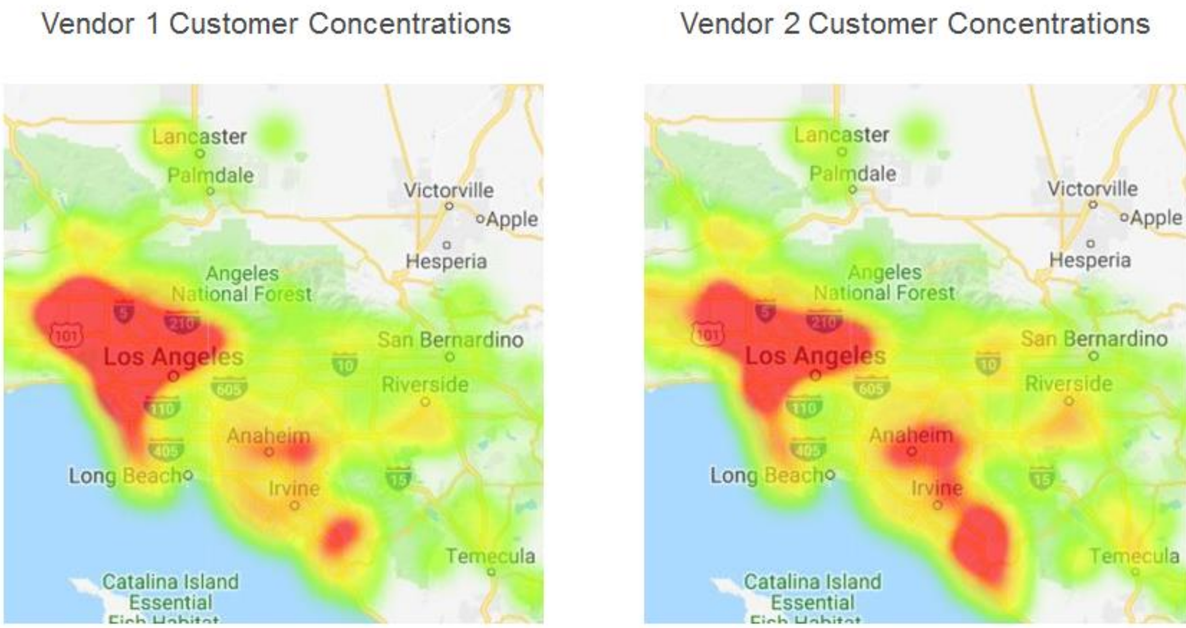


Figure 2-2 shows a heat map of pilot participants broken out by vendor. Vendor 2 has greater concentrations of customers in the Orange County region than Vendor 1, but the two vendors have similar customer concentrations in the LA Basin.

Figure 2-2: Heat Map of Pilot Participant Location By Vendor



2.3 Event Summary

Events were four hours long and took place either in the morning from 5 AM to 9 AM or in the evening from 5 PM to 9 PM. All of the events took place between February 20, 2018 and March 2, 2018. There were a total of thirteen events on nine different days, with seven morning events and six evening events. On four of the nine days, both morning and evening events were called.

Table 2-5 provides a summary of the events called during the 2017/2018 season. The thermostat vendor identifies which vendor(s) was called for each event, and the devices targeted column refers to the number of devices that were activated for an event. The last four columns record the participation status of the activated devices. Full participation refers to devices that were successfully accessed and the DR settings were in place for the entire event. An opt-out refers to customers that overrode the DR event settings. Vendor 1 kept track of which customers opted out before or during events. Vendor 2 did not, and so all opt-outs are counted as opting out before an event for Vendor 2 customers. Other refers to devices that were either “off”, in an incompatible mode, or were not accessible due to technical issues. On average, 57% of devices targeted participated in the entire event, 22% of devices targeted opted out before the event, 13% of devices targeted opted out during the event, and 8% did not participate in the event due to technical issues.

Table 2-5: Overall Event Summary

Date	Event Window	Thermostat Vendor	Devices Targeted	Full Participation	Opt-out Before	Opt-out During	Other
2/20/2018	AM	Vendor 1 and Vendor 2	9,384	51%	25%	19%	5%
2/20/2018	PM	Vendor 2 only	1,564	59%	17%	0%	24%
2/21/2018	AM	Vendor 1 and Vendor 2	9,374	55%	24%	17%	4%
2/21/2018	PM	Vendor 2 only	1,550	59%	19%	0%	22%
2/22/2018	AM	Vendor 1 and Vendor 2	9,354	55%	23%	17%	4%
2/22/2018	PM	Vendor 2 only	1,541	60%	19%	0%	21%
2/23/2018	AM	Vendor 1 only	7,801	56%	23%	20%	1%
2/26/2018	PM	Vendor 1 and Vendor 2	9,317	57%	23%	15%	5%
2/27/2018	AM	Vendor 1 and Vendor 2	9,317	55%	24%	17%	4%
2/28/2018	PM	Vendor 1 and Vendor 2	9,313	55%	23%	17%	4%
3/1/2018	AM	Vendor 1 and Vendor 2	9,575	56%	23%	17%	5%
3/1/2018	PM	Vendor 1 and Vendor 2	9,814	59%	22%	14%	5%
3/2/2018	AM	Vendor 1 and Vendor 2	9,807	59%	20%	16%	4%
Average	-	-	-	57%	22%	13%	8%

Each vendor was called for a different number of events. Vendor 1 customers were called for ten of the thirteen events and Vendor 2 customers were called for twelve of the thirteen events. Vendor 1 customers did not participate in the first three evening events due to technical difficulties, but participated in the remaining events. Vendor 2 customers were not called for a morning event on February 23, but participated in the remaining events. Both vendors were called for nine of the thirteen events, and there was one day where both vendors were called for both a morning and an evening event.

Tables 2-6 and 2-7 give the event summaries for each vendor. Vendor 2 had a higher participation rate on average than Vendor 1, with an average of 59% of Vendor 2 customers participating in events compared to 55% of Vendor 1 customers participating in events. Vendor 2 also had a higher percent of customers that did not participate due to technical issues, with 22% of customers characterized with a participation status of other, while Vendor 1 had only 1% of participants categorized as other. These differences could be due to different methods of recording participation between the two vendors, as Vendor 2 did not record different opt-out times in the same way that Vendor 1 did. Vendor 1 broke out its opt-outs into customers that opted-out before an event and customers that opted-out during an event. On average, 24% of

Vendor 1 customers opted-out before an event and 20% of Vendor 1 customers opted-out during an event. This distribution did not change significantly between morning and evening events. On average, about 19% of Vendor 2 customers opted out either before or during an event.

Table 2-6: Vendor 1 Event Summary

Date	Time	Devices Targeted	Full Participation	Opt-out Before	Opt-out During	Other
2/20/2018	AM	7,816	51%	26%	22%	1%
2/20/2018	PM					
2/21/2018	AM	7,812	55%	24%	20%	1%
2/21/2018	PM					
2/22/2018	AM	7,806	55%	24%	21%	1%
2/22/2018	PM					
2/23/2018	AM	7,801	56%	23%	20%	1%
2/26/2018	PM	7,792	56%	25%	18%	1%
2/27/2018	AM	7,792	55%	24%	20%	1%
2/28/2018	PM	7,792	54%	24%	21%	1%
3/1/2018	AM	7,793	56%	23%	21%	1%
3/1/2018	PM	8,034	58%	23%	18%	1%
3/2/2018	AM	8,029	59%	21%	19%	1%
Average	-	7,847	55%	24%	20%	1%

Table 2-7: Vendor 2 Event Summary

Date	Event Window	Devices Targeted	Full Participation	Opt-out Before	Opt-out During	Other
2/20/2018	AM	1,568	54%	22%		24%
2/20/2018	PM	1,564	59%	17%		24%
2/21/2018	AM	1,562	57%	23%		20%
2/21/2018	PM	1,550	59%	19%		22%
2/22/2018	AM	1,548	57%	22%		21%
2/22/2018	PM	1,541	60%	19%		21%
2/23/2018	AM					
2/26/2018	PM	1,525	64%	12%		24%
2/27/2018	AM	1,525	57%	23%		20%
2/28/2018	PM	1,521	61%	17%		22%
3/1/2018	AM	1,782	57%	22%		20%
3/1/2018	PM	1,780	61%	15%		23%
3/2/2018	AM	1,778	60%	20%		21%
Average	-	1,604	59%	19%		22%

3 Load Impact Estimation Methodology

The primary challenge in estimating load impacts for DR programs such as the Smart Thermostat Program is estimating how much gas participants would have used during an event in the absence of SoCalGas dispatching the program. The estimated participants' usage in the absence of the event is referred to as the counterfactual or the reference load. This was not a randomized control trial, so the primary source of data used to develop reference loads is a matched control group. Control customers were selected from a pool of non-participant customers that passed several filters that were also applied to the program participants, and were statistically matched to program participants. The fundamental idea behind the matching process is to find customers who were not subject to DR events that have similar observable characteristics to those who were subject to DR events.

Once a suitable control group was created from a group of non-participants, the next step was to use a "difference-in-differences" analysis to estimate load impacts. Difference-in-differences helps to yield more precise estimates and can correct for observable differences in load not accounted for through matching. This calculation was done using a fixed-effects regression methodology, which reduces the standard error of the estimates. The underlying approach for difference-in-differences is comprised of the following:

- Measure gas demand for both treatment and control customers on proxy (similar non-event) days;
- Measure gas demand for both treatment and control customers on event days;
- Treatment effects are calculated by taking the difference between the treatment and matched control group in the event hours and subtracting any difference between the two groups in the event period hours on proxy days.

Additional details on the load impact estimation methodology including the selection of the matched control group and difference-in-differences regression model can be found in Appendix A.

4 Load Impacts

During the 2017-2018 winter, thirteen events were called on nine different days. All thirteen events ran for four hours and were called either from 5 AM to 9 AM or from 5 PM to 9 PM. Load impacts were evaluated separately for each vendor due to differences in when vendor customers were called for events and the ways in which events were implemented for each vendor. The remainder of this section presents the load impacts for each vendor for each event the vendor participated in.

4.1 Load Impacts for Vendor 1

Table 4-1 summarizes the average and aggregate impacts for each Vendor 1 event as well as the event temperature. Vendor 1 customers participated in eight morning events and two evening events for a total of 10 events. The average hourly impact during a morning event was 0.031 thm per participant, representing a 16% load reduction from an average reference load of 0.204 thm. The average hourly aggregate impact during a morning event was a 217.152 thm load reduction from a reference load of 1,423.104 thm. The average hourly per-customer impact during an evening event was 0.012 thm, an 11% load reduction from an average reference load of 0.114 thm. The average hourly aggregate impact was a 81.795 thm load reduction from a reference load of 711.552 thm.

Time of day and corresponding levels of consumption, which are at least partially driven by temperature, were large drivers of impact differences. Morning event impacts and reference loads were consistently higher than evening event impacts and reference loads, with higher reference loads generally associated with larger event impacts. On average, there was a 5 degree temperature difference between the average morning event hour and the average evening event hour. The afternoon events also likely had reduced heating load due to the heat buildup in the home during the day as well as warmer event period temperatures.

Table 4-1: Vendor 1 Event Summary for Average Customer

Date	Event Window	Vendor 1					Avg. Event Temp. (°F)
		Average Load w/o DR (thm)	Average Load w/ DR (thm)	Average Impact (thm)	Aggregate Impact (thm)	Impact (%)	
20-Feb	AM	0.241	0.213	0.029	201.36	12.5%	44.8
21-Feb	AM	0.214	0.182	0.032	224.78	15.5%	50.2
22-Feb	AM	0.222	0.192	0.031	214.12	14.1%	48.7
23-Feb	AM	0.206	0.176	0.030	211.73	15.3%	48.3
26-Feb	PM	0.109	0.097	0.012	85.01	11.4%	55.5
27-Feb	AM	0.192	0.161	0.031	214.71	16.5%	46.8
28-Feb	PM	0.123	0.108	0.015	105.33	12.7%	54.2
1-Mar	AM	0.195	0.163	0.032	222.01	16.4%	51.0
1-Mar	PM	0.109	0.101	0.008	55.05	8.0%	54.7
2-Mar	AM	0.154	0.121	0.033	231.36	21.6%	52.3
All Events							
Avg.	**AM**	0.204	0.172	0.031	217.15	16.0%	48.9
Avg.	**PM**	0.114	0.102	0.012	81.80	10.7%	54.8

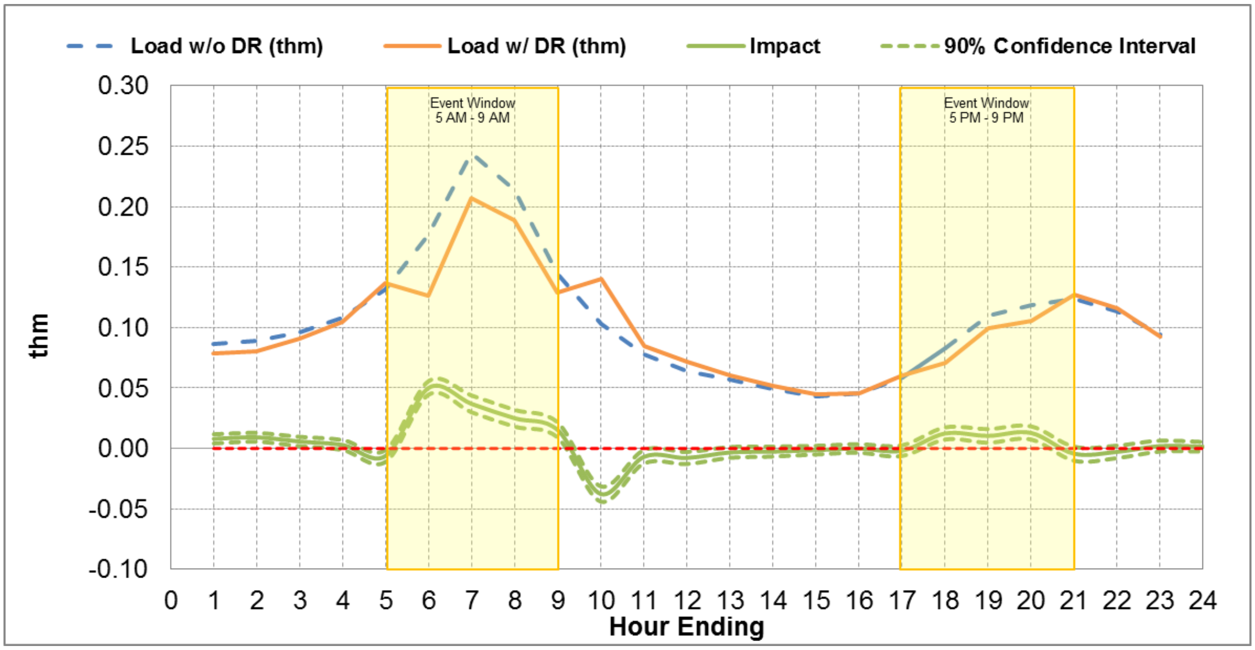
Vendor 1 customers experienced three different event day types: days with only morning activations, days with only evening activations, and days with both morning and evening activations. There was one day (March 1) where both a morning and evening event were called. Figure 4-1 provides the average per customer load with DR, load without DR (reference load), and load impact for that day. The load shape and usage patterns for the morning event window in Figure 4-1 are illustrative of customer behavior during all morning events, and the load shapes and usage patterns during the evening event window in Figure 4-1 are illustrative of the customer load shapes during all evening events.[5] Morning event windows had the highest overall reference load and highest overall impacts, with the largest impact occurring in the first hour of the morning event. Evening events had a much lower reference load and lower impacts.

In the hour following both morning and evening events, there is what is referred to as "snap back", which is when customer gas usage is higher after an event than would be expected if an event had not taken place. This is because during an event, the Vendor 1 thermostat temperature is lowered by up to 3°F. After the event, the thermostat temperature is returned to its pre-event temperature. In order to increase the temperature in the home to the non-event temperature, the HVAC system has to run more consistently for up to the first hour following the event (or longer). This can result in increased consumption in the hours following an event compared to what would typically be expected on a similar non-event day. The average snap back for Vendor 1 customers following morning events was 0.033 thms, with the load of the average participant 26% greater than customers that did not participate in the event. The

[5] This figure does not represent average morning event impacts across all morning events or average evening event impacts across all evening events. Its purpose is to illustrate what both events looked like, and shows exact impacts only for days where both morning and evening events were called.

average snap back for Vendor 1 customers following evening events was 0.015 therms, representing a 12% load increase compared to customers that did not participate in the event.

Figure 4-1: Vendor 1 Average Hourly Load Impact per Customer on Average Event Day with both Morning and Evening Events Called



4.2 Load Impacts for Vendor 2

Table 4-2 summarizes the average and aggregate impacts for each Vendor 2 event as well as the event temperature. Vendor 2 customers participated in six morning events and six evening events for a total of twelve events. The average impact during a morning event was 0.050 thm, representing a 25% reduction from an average reference load of 0.205 thm. The average hourly aggregate impact was a 102.308 thm reduction from a reference load of 415.905 thm. The average impact during an evening event was 0.019 thm, representing a 16% load reduction from an average reference load of 0.120 thm. The average aggregate impact was a 37.768 thm reduction from a reference load of 243.48 thm.

Similar to Vendor 1, all events Vendor 2 customers participated in were within approximately 10°F of each other. Time of day and corresponding levels of consumption, which are at least partially driven by temperature, were large drivers of impact differences. Morning event impacts and reference loads were also consistently higher than evening event impacts and reference loads, with higher reference loads generally associated with larger event impacts.

Table 4-2: Vendor 2 Event Summary for Average Customer

Date	Event Window	Vendor 2					Event Temp. (°F)
		Average Load w/o DR (thm)	Average Load w/ DR (thm)	Average Impact (thm)	Aggregate Impact (thm)	Impact (%)	
20-Feb	AM	0.244	0.192	0.052	105.141	21.2%	44.78
20-Feb	PM	0.147	0.116	0.031	63.701	22.0%	51.76
21-Feb	AM	0.218	0.166	0.052	104.957	23.7%	50.23
21-Feb	PM	0.133	0.110	0.023	46.844	18.0%	53.24
22-Feb	AM	0.224	0.176	0.048	96.413	21.2%	48.70
22-Feb	PM	0.127	0.111	0.016	32.466	13.3%	53.51
26-Feb	PM	0.104	0.087	0.017	34.285	16.4%	55.49
27-Feb	AM	0.195	0.145	0.050	101.858	25.9%	46.81
28-Feb	PM	0.111	0.101	0.010	20.764	9.6%	54.23
1-Mar	AM	0.198	0.140	0.058	116.673	28.7%	50.99
1-Mar	PM	0.099	0.085	0.014	28.552	14.3%	54.73
2-Mar	AM	0.152	0.108	0.044	88.805	29.1%	52.33
All Events							
Avg.	**AM**	0.205	0.155	0.050	102.308	25.0%	48.97
Avg.	**PM**	0.120	0.101	0.019	37.768	15.6%	53.83

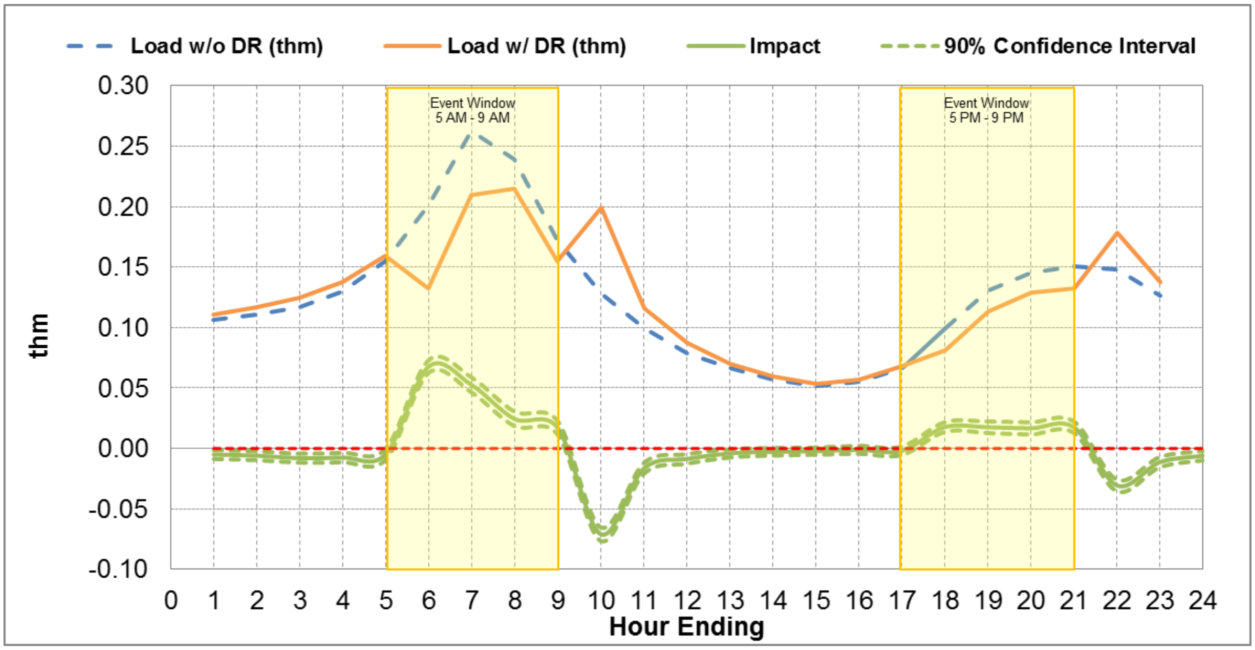
Vendor 2 customers experienced three different event day types: days with only morning events, days with only evening events, and days with both morning and evening events. There were four days where both a morning and evening event was called in the same day. Figure 4-1 provides the average per customer load with DR, load without DR (reference load), and load impact for the average event day for Vendor 2 customers where there were both morning and evening activations. The load shape and usage patterns for the morning event window in Figure 4-2 are illustrative of customer behavior during all morning events, and the load shapes and usage patterns during the evening event window in Figure 4-2 are illustrative of the customer load shapes during all evening events.[6] Morning event windows had the highest overall reference load and highest overall impacts, with the largest impact occurring in the first hour of the morning event. Evening events had a much lower reference load and lower impacts.

In the hour following the event, the snap back for the average Vendor 2 customer was larger than with Vendor 1 customers. The average snap back for Vendor 2 customers following morning events was 0.068 thm, with the load of the average participant 60% greater than customers that did not participate in the event. The average snap back for Vendor 2 customers following evening events was 0.028 thm, representing a 24% load increase compared to customers that did not participate in the event. In the evening, the post-event snap back

[6] This figure does not represent average morning event impacts across all morning events or average evening event impacts across all evening events. Its purpose is to illustrate what both events looked like, and shows exact impacts only for days where both morning and evening events were called.

increased the hourly consumption to a new higher hourly peak for Vendor 2 treatment customers between the hours of 9 PM and 10 PM.

Figure 4-2: Vendor 2 Average Hourly Load Impact per Customer on Average Event Day with both Morning and Evening Activations



4.3 Comparison of Vendor Load Impacts

Table 4-3 contains a summary of the average customer load impacts for each event for each vendor. The two vendors experienced a different mix of events during the 2017-2018 winter. Vendor 1 customers participated in seven morning events and three evening events, while Vendor 2 customers participated in six morning events and six evening events. Both vendors participated together in a total of nine events. In this section, we will use events where both vendors participated when comparing impacts since during these events customers experienced the same weather conditions. Each vendor took a different approach to the thermostat setback during the events, which is evident in the different load impacts and snap back patterns observed between the two vendors under similar weather conditions.

Vendor 2 and Vendor 1 customers both participated in a total of six morning events. During morning events, the average temperature was 48.97°F. Vendor 2 customers had a slightly higher baseline than Vendor 1 customers, with an average reference load of 0.205 thm compared to the Vendor 1 average reference load of 0.203 thm. Vendor 2 also had a much higher event impact than Vendor 1, with an average hourly impact of 0.050 thm during the event, 25% of the reference load. Vendor 1 customers had an average hourly impact of 0.031 thm, 16% of the reference load. However, as discussed above it should be noted that Vendor 2 customers also had a much larger snapback than Vendor 1 customers in the hour following an event, with Vendor 2 DR customers using 60% more load than would be expected in the absence of an event and Vendor 1 customers using 26% more load than would be expected in the absence of an event.

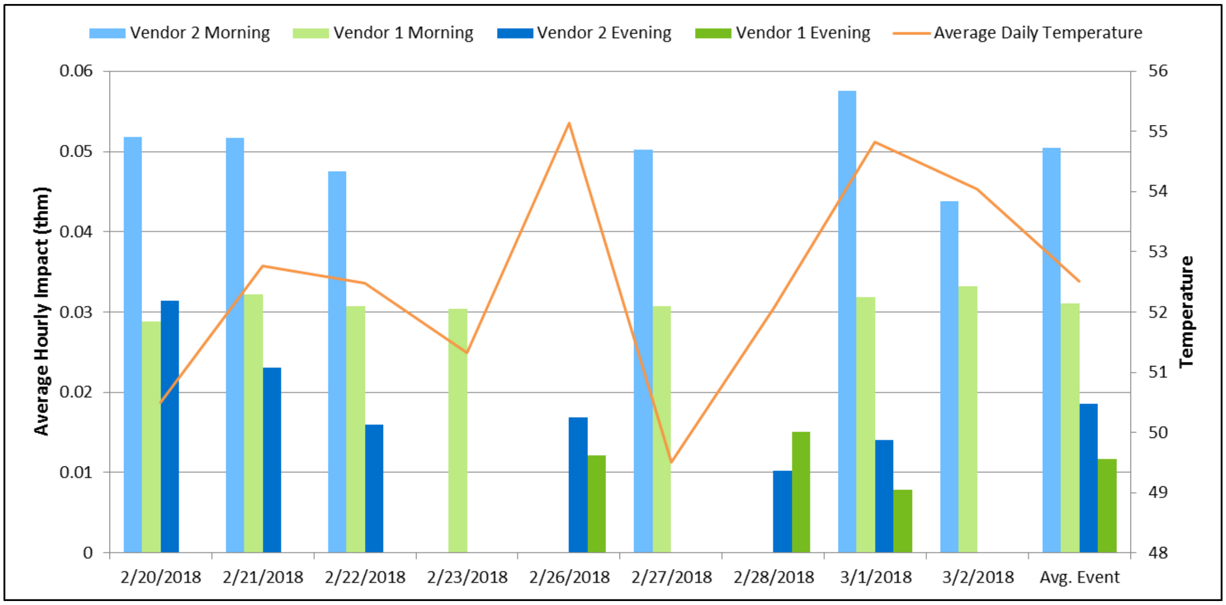
Vendor 2 and Vendor 1 customers both participated in a total of three evening events. During evening events, the average temperature was 54.82°F. Vendor 1 customers had a higher baseline than Vendor 2 customers, with an average reference load of 0.114 thm, compared to the Vendor 2 reference load of 0.104 thm. Similar to the morning impacts, Vendor 2 had a slightly higher event impact than Vendor 1, with an average hourly impact of 0.014 thm, 13% of the reference load. Vendor 1 customers had an average hourly impact of 0.012 thm, 10.7% of the reference load. Vendor 2 also again had a higher snapback after evening events than Vendor 1, seeing a 24% increase in load relative to the reference load in the hour following an event. Vendor 1 customers saw a 12% increase in load relative to the reference load in the hour following an event.

Table 4-3: Summary Load Impacts for Common Events Across Both Vendors

Date	Event Window	Vendor 1				Vendor 2				Event Temp. (°F)
		Average Load w/o DR (thm)	Average Load w/ DR (thm)	Average Impact (thm)	Impact (%)	Average Load w/o DR (thm)	Average Load w/ DR (thm)	Average Impact (thm)	Impact (%)	
20-Feb	AM	0.241	0.213	0.029	12.5%	0.244	0.192	0.052	21.2%	44.78
21-Feb	AM	0.214	0.182	0.032	15.5%	0.218	0.166	0.052	23.7%	50.23
22-Feb	AM	0.222	0.192	0.031	14.1%	0.224	0.176	0.048	21.2%	48.70
26-Feb	PM	0.109	0.097	0.012	11.4%	0.104	0.087	0.017	16.4%	55.49
27-Feb	AM	0.192	0.161	0.031	16.5%	0.195	0.145	0.050	25.9%	46.81
28-Feb	PM	0.123	0.108	0.015	12.7%	0.111	0.101	0.010	9.6%	54.23
1-Mar	AM	0.195	0.163	0.032	16.4%	0.198	0.140	0.058	28.7%	50.99
1-Mar	PM	0.109	0.101	0.008	8.0%	0.099	0.085	0.014	14.3%	54.73
2-Mar	AM	0.154	0.121	0.033	21.6%	0.152	0.108	0.044	29.1%	52.33
Common Events across both vendors										
Avg.	**AM**	0.203	0.172	0.031	16.1%	0.205	0.155	0.050	25.0%	48.97
Avg.	**PM**	0.114	0.102	0.012	10.7%	0.104	0.091	0.014	13.4%	54.82

Figure 4-3 illustrates the variation in impacts across events for each vendor for all events. Vendor 2 event impacts are blue and Vendor 1 event impacts are green. Vendor 2 consistently delivered larger impacts than Vendor 1 customers for morning events, and morning events consistently had larger impacts than evening events. Vendor 1 impacts varied very little across each event type, with all morning event impacts within 0.002 thm of the average morning event impact and all evening event impacts within 0.004 thm of the average evening event impact. Vendor 2 impacts varied more, with one morning event impact up to 0.008 thm greater than the average morning event impact and one evening event impact up to 0.011 thm greater than the average evening event impact.

Figure 4-3: Event Impact Summary by Vendor



4.4 Daily Therm Savings

Table 4-4 illustrates the average and aggregate daily savings for each event day type by vendor. It should be noted that neither vendor saw statistically significant daily savings for any event day type due to the snap-back in the hours following both morning and evening events. However, with a larger sample size it is possible that both vendors could see statistically significant daily savings in the future. Vendor 1 customers had a maximum daily saving of 4.9%[7] on March 1, when SoCalGas called both a morning and evening event. Vendor 2 customers had maximum average daily savings when only morning events were called, with an average daily impact of 2.5%. However, due to the small number of each event type, these numbers may not represent which event type would provide the largest daily savings on average.

Table 4-4: Estimated Daily Therm Savings by Vendor

Vendor	Event Day Type	Average Daily Impact (thm)	Aggregate Daily Impact (thm)	Aggregate Daily Impact (CCF)	Daily Impact (%)	Statistically Significant	Event Day Type Count
Vendor 1	AM Only	0.068	472.147	458.395	2.3%	No	6
	PM Only	0.047	328.490	318.923	1.8%	No	2
	AM & PM	0.118	826.482	802.410	4.9%	No	1
Vendor 2	AM Only	0.066	133.083	129.207	2.5%	No	2
	PM Only	0.016	31.463	30.546	0.6%	No	2
	AM & PM	0.045	91.226	88.569	1.6%	No	4

[7] Not statistically significant.

5 Conclusions and Recommendations

Table 5-1 provides a summary of the 2017-2018 winter SoCalGas Smart Thermostat Program hourly event impacts for each event and for the average morning and evening event by vendor. The average load reduction for a Vendor 1 morning event was 0.031 thm per participant leading to an aggregate reduction of 217.152 thm, or 16.0%. The average load reduction for a Vendor 1 evening event was 0.012 thm, leading to an aggregate reduction of 81.795 thm, or 10.7%. The average load reduction for a Vendor 2 morning event was 0.050 thm, leading to an aggregate reduction of 102.308 thm, or 25.0%. The average load reduction for a Vendor 2 evening event was 0.014 thm, leading to an aggregate reduction of 37.768 thm, or 15.6%. Overall, Vendor 2 customers consistently produced larger average event impacts relative to Vendor 1 customers. Across both vendors morning events provided larger impacts relative to evening events. Due to gas usage snap-backs after the event window, neither vendor had statistically significant daily therm savings, regardless of when an event was called or how many events were called.

Table 5-1: Winter 2017-2018 Load Impact Estimates

Date	Event Window	Vendor 1				Vendor 2				Event Temp. (°F)
		Number of Participants	Average Impact (thm)	Aggregate Impact (thm)	Impact (%)	Number of Participants	Average Impact (thm)	Aggregate Impact (thm)	Impact (%)	
20-Feb	AM	6,976	0.029	201.355	12.5%	2,029	0.052	105.141	21.2%	44.78
20-Feb	PM	-	-	-	-	2,029	0.031	63.701	22.0%	51.76
21-Feb	AM	6,976	0.032	224.779	15.5%	2,029	0.052	104.957	23.7%	50.23
21-Feb	PM	-	-	-	-	2,029	0.023	46.844	18.0%	53.24
22-Feb	AM	6,976	0.031	214.118	14.1%	2,029	0.048	96.413	21.2%	48.70
22-Feb	PM	-	-	-	-	2,029	0.016	32.466	13.3%	53.51
23-Feb	AM	6,976	0.030	211.733	15.3%	-	-	-	-	48.25
26-Feb	PM	6,976	0.012	85.005	11.4%	2,029	0.017	34.285	16.4%	55.49
27-Feb	AM	6,976	0.031	214.712	16.5%	2,029	0.050	101.858	25.9%	46.81
28-Feb	PM	6,976	0.015	105.334	12.7%	2,029	0.010	20.764	9.6%	54.23
1-Mar	AM	6,976	0.032	222.013	16.4%	2,029	0.058	116.673	28.7%	50.99
1-Mar	PM	6,976	0.008	55.048	8.0%	2,029	0.014	28.552	14.3%	54.73
2-Mar	AM	6,976	0.033	231.357	21.6%	2,029	0.044	88.805	29.1%	52.33
All Events										
Avg.	**AM**	6,976	0.031	217.152	16.0%	2,029	0.050	102.308	25.0%	48.87
Avg.	**PM**	6,976	0.012	81.795	10.7%	2,029	0.019	37.768	15.6%	53.83
Common Events across both vendors										
Avg.	**AM**	6,976	0.031	218.055	16.1%	2,029	0.050	102.308	25.0%	48.97
Avg.	**PM**	6,976	0.012	81.795	10.7%	2,029	0.014	27.867	13.4%	54.82

The SoCalGas Thermostat program is one of the first, if not the first, natural gas based demand response programs in the US. It has proven that smart thermostats can be used to reduce demand for natural gas during targeted periods of time in the morning and the evening.

However, the snap back following the event when a customer's preferred temperature settings are restored can be quite significant, and generally erase any net daily therm savings. Though, with larger sample sizes it may be possible to achieve statistically significant net daily therm savings. The thermostat setback strategy was also shown to be important, and can significantly affect the size of the load reductions and the post-event snap back, as shown by the different vendor performance. The performance differential actually provides a valuable data point, in that the setback strategy could be fine-tuned or adjusted to better meet a distribution system's specific need.

From a technical perspective, it's clear the program met the objectives of reducing gas consumption during specific windows of time. However, without statistically significant net daily therm savings there is an open question regarding whether the program created value from a reliability or economic perspective. While on the electric grid blackouts can be caused by an immediate supply/demand imbalance, gas supply shortages causing low gas system pressure and deliverability issues are typically a more protracted event due to the slow speed of how gas travels. It's unclear how much of a supply shortage may exist for only a few hours in Southern California. If there aren't supply shortages lasting only a few hours, it's possible that traditional energy efficiency and behavioral conservation based programs, most notably Seasonal Energy Update energy reports, may yield greater savings over longer periods of supply shortage. These interventions have the dual benefit of providing significant gas savings on both DR event days and non-DR days throughout the winter.

Appendix A Load Impact Methodology Details

A.1 Selection of Matched Control Group

Customers who signed up to participate in the Vendor 1 or Vendor 2 programs are inherently different from customers who did not sign up to participate in the SoCalGas DR programs or customers who were not targeted by the thermostat vendors. For this reason, a control group must be constructed using statistical matching. It is possible that the customers who enrolled in the SoCalGas DR programs had particular characteristics that made them more likely to enroll than customers who did not enroll or customers who were not targeted to enroll. This is particularly important when studying early adopters of a new technology such as smart thermostats who may have very different gas consumption patterns from those of the rest of the population. This type of behavior introduces selection bias because the difference in usage between the two groups caused by characteristics differences could be mistaken as the impact of treatment. A matched control group is the primary source for reference loads which are used to estimate impacts. The method used to assemble the matched control group is designed to ensure that the control group load on event days is an accurate estimate of what load would have been among SoCalGas DR customers on event days if an event hadn't taken place.

Nexant selected the control groups using propensity score matching to find residential SoCalGas customers who are non-DR program participants with load shapes most similar to those of SoCalGas DR participants. In this procedure, a probit model is used to estimate a score for each customer based on a set of observable variables that are assumed to affect the decision to join a SoCalGas DR program. A probit model is a regression model designed to estimate probabilities—in this case, the probability that a customer would enroll in a SoCalGas DR program. The score can be interpreted two different ways. First, the propensity score can be thought of as a summary variable that includes all the relevant information in the observable variables about whether a customer would choose to participate in a SoCalGas DR program. Each customer in the DR program population was matched with a customer in the non-DR population that has the closest propensity score. The second way to think of the propensity score is as the probability that a customer will join a SoCalGas DR program based on the included independent variables. Thinking of it this way, each customer in the control group was matched to a SoCalGas DR customer with a similar probability of joining a SoCalGas DR program given the observed variables. Nexant performed the match within four clusters that grouped customers based on their load shape similarity. In other words, the match was conducted separately for SoCalGas DR customers that had load shapes similar to one-another.

In order to select the probit model used to find the best match for each treatment customer, "out of sample" testing was performed to evaluate several different probit model specifications. Out of sample testing involves running each of the different model specifications using all but one of the proxy days, leaving the unused proxy day to test how well the model performed. By leaving a different proxy day out each time the matching selection is run, one is able to see how well the matches look on a day that was not used to select the match. During this process, sixteen different model specifications were tested using different observable variables including usage during event hours, average total daily usage, and usage from 12pm to 9pm. For each of the eleven models six different "calipers" were tested. Calipers set a maximum threshold of how large the difference in propensity scores can be for a matched pair. During the matching process, the treatment customers are matched to the control customer who has the most similar propensity score to them. Additionally, treatment customers can only be matched to a control customer in the same load shape cluster. If the difference between a treatment customer and control customer's propensity score is higher than the set caliper, the treatment customer will not be matched. Therefore, a caliper sets the standard for how close the matched pairs need to be. In order to find the closest control customer matches, the SoCalGas DR customers were split out by vendor to find the optimal probit model for each vendor. This provided much closer matches for each of the two thermostat vendor customers.

Figure A-1 and Figure A-2 show the results of the matched control group for the two thermostat vendors. The Vendor 1 customers match very well to their matched control group on proxy days. Vendor 2 also matches very well, although not quite as well as Vendor 1 customers do. This is in part due to the difference in sample size between the two vendors. Vendor 1 has over 7,000 customers while Vendor 2 has less than 2,000 customers. Both vendors also do not match perfectly during the daytime hours. This is because when selecting the model matching during event hours was given priority over non-event hours, since non-event hours are not as crucial for estimating event impacts.

Figure 5-1: Hourly Average Demand for Vendor 1 Customers on Proxy Days

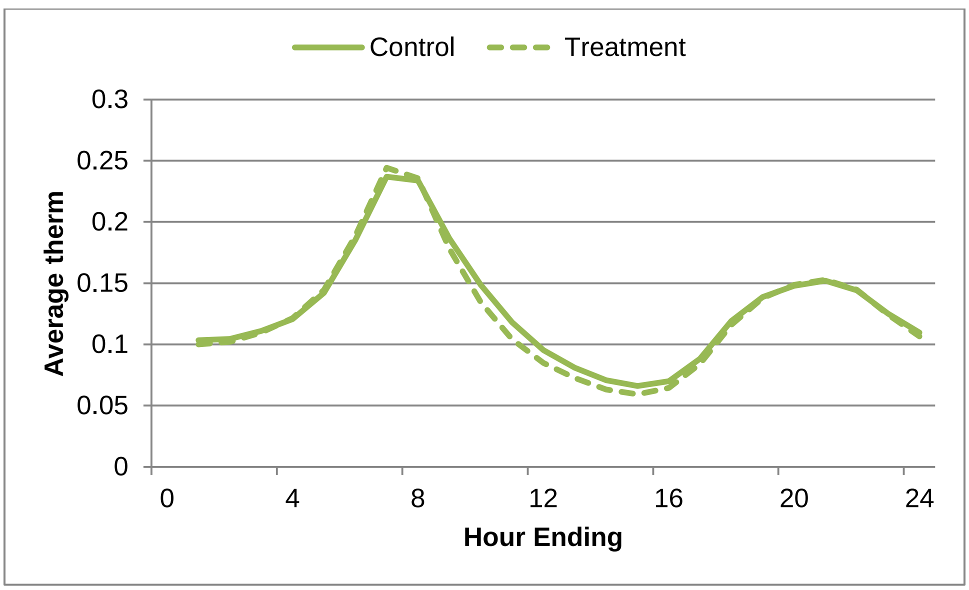
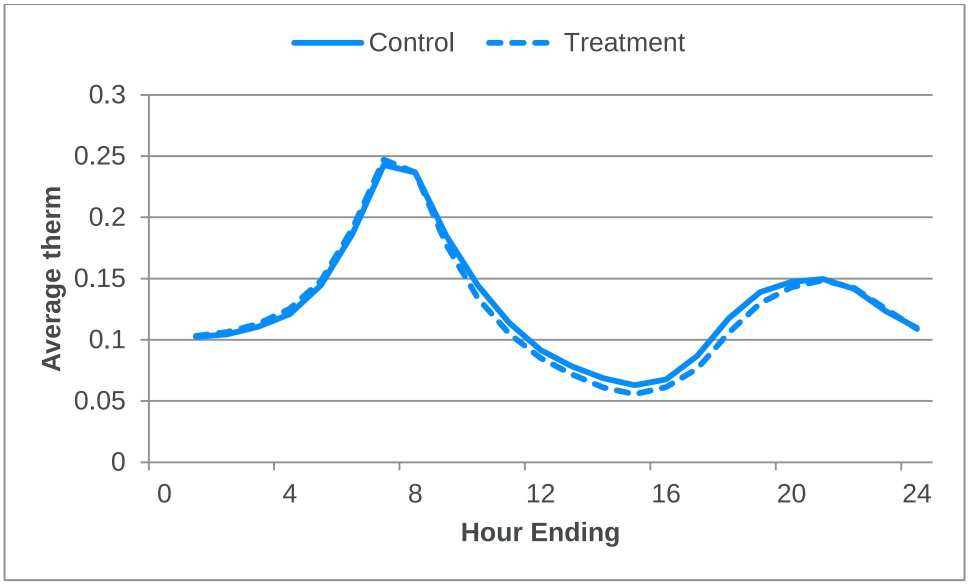


Figure 5-2: Hourly Average Demand for Vendor 2 Customers on Proxy Days



A.2 Difference-in-Differences Regression Models

After a matched control group was created, program impacts were estimated using a difference-in-differences regression model. This methodology is based on the assumption that the program impact is equal to the difference in usage between the treatment and the control groups during the event period, minus any pre-existing difference between the two groups. When using difference-in-differences, the matched control group does not need to perfectly match the treatment group on the proxy days. Any differences that may be due to observable differences in load not accounted for through matching will be netted out by the differencing. It is a reasonable assumption that any unobservable differences between the treatment and the control groups during the event period hours on proxy days stay the same during the DR event hours. Therefore any further difference between the groups in the DR event hours is assumed to be the impact of treatment. This regression model is shown in Equation A-1 below:

Equation A-1: Difference-in-Differences Models

$$thm_{i,t} = a + b \cdot Treatment_i + c \cdot Event_t + d \cdot (Treatment_i \cdot Event_t) + u_t + \varepsilon_{i,t} \text{ for } i \in \{1, \ldots, n_i\} \text{ and } t \in \{1, \ldots, n_t\}$$

Variable	Definition
i, t, n	Indicate observations for each individual i, date t and event number n
a	The model constant
b	Pre-existing difference between treatment and control customers
c	The difference between event and proxy days common to both treatment and control group members[8]
d	The net difference between treatment and control group customers during event days–this parameter represents the difference-in-differences
u	Time effects for each date that control for unobserved factors that are common to all treatment and control customers but unique to the time period
v	Customer fixed effects that control for unobserved factors that are time-invariant and unique to each customer; fixed effects do not control for fixed characteristics such as air conditioning that interact with time varying factors like weather
E	The error for each individual customer and time period
$Treatment$	A binary indicator or whether or not the customer is part of the treatment or control group
$Event$	A binary indicator of whether an event occurred that day–impacts are only observed if the customer is enrolled in DR ($Treatment$ = 1) and it was an event day

The model was estimated using both event days and proxy days, which are nonevent days with similar weather conditions and system load usage as days when events are called. The difference in loads between treatment and control customers for the event period hours on proxy days is subtracted from the differences on DR event hours to adjust for any differences between the treatment and control groups due to random chance.

As an extra validation, the simple difference in loads between treatment and control customers during event hours on event and proxy days was calculated to ensure that the regression model produces a similar output. The regression model also reduces the standard errors of the impact estimates compared to those that can be calculated from a simple difference in loads.

[8] In practice, this term is absorbed by the time effects, but it is useful for representing the model logic.

REPORT

2018-2019 Winter Load Impact Evaluation of SoCalGas Smart Therm Program

CALMAC Study ID SCG0224

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1 Executive Summary

SoCalGas was directed by the California Public Utilities Commission (CPUC) to continue and expand the SoCalGas Smart Therm Program in response to the potential need for demand reductions during the 2018-2019 winter and future winters. The Smart Therm Program for 2019 was an offering where customers were recruited from an installed smart thermostat customer base of six vendors, and offered incentives to enroll. The program was event-based, meaning that it targeted relatively few hours on days of peak demand. Load reductions were attained on event days from temporary degree setbacks on thermostats, which led to a reduction in demand for heating. All activations took place either between the hours of 5 AM to 9 AM or 6 PM to 10 PM[1].

Gas load impacts (usage reductions) on event days were estimated by applying the best practices that have been developed for electric Demand Response (DR) program measurement and evaluation in California. As in the annual electric DR evaluations, the SoCalGas Smart Therm Program load impact estimates leverage the wide availability of interval data from advanced meters to estimate the usage reductions.

Table 1-1 provides a summary of the 2018-2019 winter Smart Therm Program hourly event impacts for each event and for the average morning and evening event, along with the average number of customers that participated in an event. It should be noted that the number of customers called for morning and evening events differed, so the average and aggregate impacts for these events cannot be directly compared. The average load reduction for a morning event hour was 0.027 CCF/hr per participant leading to an aggregate reduction of 0.093 MMcf/hr, or 15.1%. The average load reduction per participant for an evening event hour was 0.020 CCF/hr, leading to an aggregate reduction of 0.019 MMcf/hr, or 15.5%.

Table 1-1: Winter 2018-2019 Hourly Load Impact Estimates[2]

Event Window	Number of Customers Called	Average Hourly Impact (CCF/hr)	Aggregate Hourly Impact (MMcf/hr)	Impact (%)
5am – 9am	33,895	0.027	0.093	15.10%
6pm – 10pm	9,208	0.020	0.019	15.50%

Table 1-2 provides a summary of 2018-2019 event savings for the average morning and evening event. These event savings are the sum of the hourly event impacts, and do not include the load lost after the event due to snap back. The average event savings for a morning event

[1] A small subset of customers were part of a testing strategy that involved an 8-hour event with a 2-degree setback. Testing strategy results are reported in Section 4.4.

[2] All impacts were originally calculated in therms and then divided by a conversion factor of 1.03 to get CCF.

was 0.110 CCF per participant leading to aggregate event savings of 0.372 MMcf. The average event savings for an evening event was 0.083 CCF per participant, leading to aggregate event savings of 0.076 MMcf.

Table 1-2: Winter 2018-2019 Event Savings Estimates

Event Window	Number of Customers Called	Average Event Savings (CCF)	Aggregate Event Savings (MMcf)	Savings (%)
5am – 9am	33,895	0.110	0.372	15.10%
6pm – 10pm	9,208	0.083	0.076	15.50%

Table 1-3 provides a summary of 2018-2019 net daily savings for the average morning and evening event. Daily savings include savings that occurred during the event as well as any pre- or post-event heating that may increase load relative to what would have occurred in the absence of an event. The average daily savings for a morning event was 0.061 CCF per participant leading to aggregate savings of 0.207 MMcf, or 2.24%. The average daily savings for an evening event was 0.034 CCF per participant leading to aggregate daily savings of 0.031 MMcf, or 1.27%.

Table 1-3: Winter 2018-2019 Daily Savings Estimates

Event Window	Number of Customers Called	Average Daily Savings (CCF)	Aggregate Daily Savings (MMcf)	Savings (%)
5am – 9am	33,895	0.061	0.207	2.24%
6pm – 10pm	9,208	0.034	0.031	1.27%

The SoCalGas Smart Therm program is one of the first, if not the first, natural gas based demand response programs in the US. It has proven that smart thermostats can be used to reduce demand for natural gas during targeted periods of time in the morning and evening. However, as discussed in section 4.2, the thermostat setback strategy was also shown to be important, and can significantly affect the size of the load reductions and the post-event "snap back." The snap back following the event when a customer's preferred temperature settings are restored can be quite significant, and greatly reduces net daily CCF savings compared to the event savings. Two new event implementation strategies were tested this year to determine if snap back could be reduced. While these efforts reduced snap back, they did not necessarily reduce daily consumption relative to current implementation strategies.

From a technical perspective, it's clear the program met the objectives of significantly reducing gas consumption during specific windows of time. However, due to gas usage snap backs in the hours following events, the net daily CCF savings that resulted from this program were only in the 1% to 2% range depending on the timing of the event.

2 Overview

SoCalGas was directed by the California Public Utilities Commission (CPUC) to continue and expand the SoCalGas Smart Therm Program in response to the potential need for demand reductions during the 2018-2019 winter and future winters. The Smart Therm Program for 2019 was an offering where six vendors (Nest, ecobee, Honeywell, Radio Thermostat, Lux, and Emerson/Sensi) participated. Customers were recruited from their installed smart thermostat customer bases, and offered incentives to enroll. Recruitment was conducted by the thermostat vendors or by SoCalGas.

The program was event-based, meaning that it targeted relatively few hours on days of peak demand. Load reductions were attained on event days from temporary degree setbacks on thermostats, which led to a reduction in demand for heating. Further details regarding the program design and implementation are contained in Section 2.1.

Gas load impacts on event days were estimated by applying the best practices that have been developed for electric Demand Response (DR) program measurement and evaluation in California. In 2008, the California Public Utilities Commission (CPUC) and joint electric Investor-Owned Utilities (IOUs) developed California's Load Impact Protocols, which required the electric utilities to conduct annual evaluations of all DR programs in the state. As in the annual electric DR evaluations, the SoCalGas Smart Therm Program load impact estimates leverage the wide availability of interval data from advanced meters to estimate usage reductions. The program evaluation methodology that uses a matched control group is similar to how most electric DR programs have been evaluated for several years, including Southern California Edison's (SCE's)® Smart Energy Program (also known as Peak Time Rebate),[3] which is also a smart thermostat program.

Throughout this report, Nexant will define event, program, and load as follows:

- Event – refers to the four-hour period during which SoCalGas adjusted a customer's thermostat in order to reduce heating demand during that period (an "activation"). There can be multiple events in a single day.
- Program – refers to the SoCalGas Smart Therm Program.
- Load – refers to customer gas usage, measured in hundred cubic feet (CCF) or million cubic feet (MMcf).

[3] Nexant. "2018 Load Impact Evaluation of Southern California Edison's Smart Energy Program." April 1, 2019. CALMAC Study ID: SCE0433.

2.1 Program Design and Implementation

The SoCalGas Smart Therm Program allows eligible residential customers[4] with a natural gas furnace and an approved smart thermostat to receive incentives for reducing gas use. This winter's program season ran from December 1, 2018 to April 1, 2019 and included a wider range of smart thermostats. Along with Nest and ecobee, who participated in the previous year's program, customers with smart thermostats from Honeywell, Lux, Radio Thermostat and Emerson/Sensi were able to participate.

The Smart Therm program is voluntary and only those customers who sign up for the program through their smart thermostat vendor can participate. SoCalGas offers various incentives to encourage customers to enroll and participate. Customers earn an initial $50 for enrolling in the program. Those who enrolled by March 1, 2019 and stay enrolled through April 1, 2019 were eligible to receive an additional $25 and customers receive this $25 credit for each winter season they remain enrolled. As such, customers who participated in the 2018 Demand Response season received a $25 credit for remaining in the program for the 2019 winter season.

Program events are four-hours in length and can result in up to a four-degree adjustment to a customer's thermostat.[5] Events may be called from 5:00 AM to 9:00 AM and from 6:00 PM to 10:00 PM on weekdays that are not Federal holidays. Customers receive a notification 10- to 12-hours before the event. Customers may override the setback, which opts the customer out of the event, without penalty. Once the activations came to an end, thermostats were returned to their original set points. Two aggregators, EnergyHub and Whisker Labs, provided dispatch related services for the thermostat vendors.

To recruit customers into the program, SoCalGas promoted the program using social media and radio advertising, and the vendors reached out to customers who had already adopted smart thermostat technologies. SoCalGas additionally sent out an email campaign for the program.

2.2 2019 Changes to the Smart Therm Program

SoCalGas introduced several program design changes this year. They changed the evening event window from 5 PM to 9 PM to 6 PM to 10 PM and eliminated the possibility for customers to participate in multiple events in a single day. The main reason for limiting customers to only one event per day was to prevent customer fatigue and to see if that would increase participation in events. Additionally, during the 2019 season SoCalGas tested two new event implementation strategies on a subset of customers to determine if the new strategies were able to reduce gas consumption, reduce post event snap back, and increase customer satisfaction. These strategies were tested from February 19 through February 21. Table 2-1 depicts the details of the two strategies that were implemented as well as the standard implementation

[4] Eligible customers must have an active SoCalGas account with an Advanced Meter and have a participating smart thermostat controlling a natural-gas-fired furnace in their residence. Additional information is online: https://www.socalgas.com/save-money-and-energy/rebates-and-incentives/smart-therm/smart-therm-faq

[5] Degree setback varied by thermostat vendor, with the majority of vendors adjusting up to 3-degrees only.

method for reference. The first test strategy had the same event length as a typical implementation method, but randomly rolled customers off the event within a 30-minute period just after the event ended (e.g. 9 AM – 9:30 AM). The second test strategy was 8 hours in length, with only a 2-degree offset. The results of the test implementation strategies can be found in Section 4.4 of this report.

Table 2-1: Summary of 2019 Test Implementation Strategies

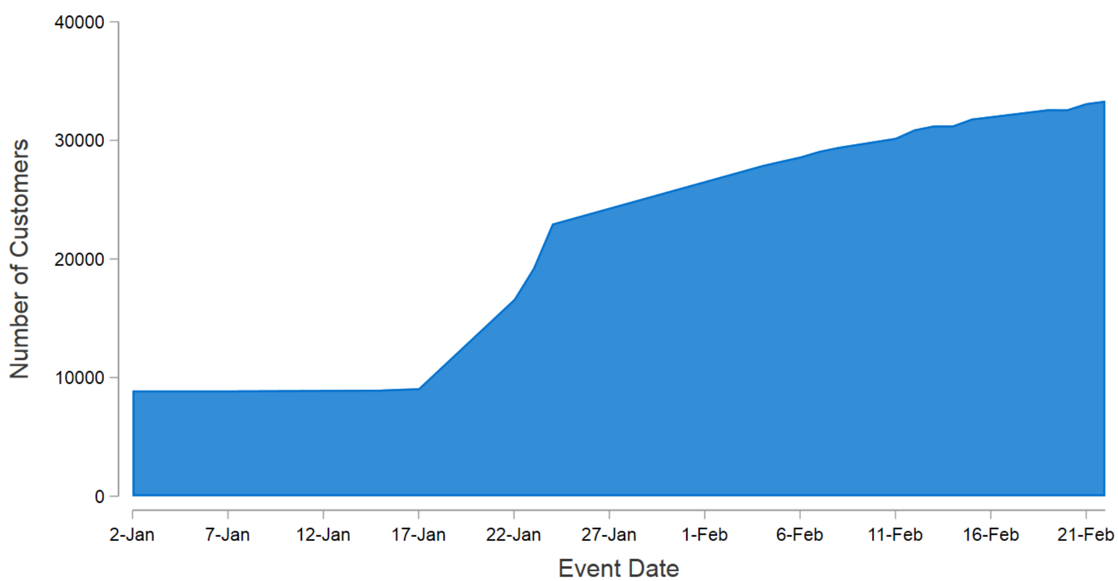
Implementation Method	Event Length	Degree Offset	Event Time
Default Strategy	4 hours	Up to 4 degrees	5 AM – 9 AM or 6 PM – 10 PM
Test Strategy 1	4 hours	3 degrees	5 AM – 9 AM, with a 30-minute randomized device withdrawal between 9:00-9:30 am
Test Strategy 2	8 hours	2 degrees	5 AM – 1 PM

2.3 Program Participants

2.3.1 Enrollment

At the time of the evaluation (March 1, 2019), the vendors had 37,159 customers and 42,627 thermostats enrolled in the program and at the end of recruitment (June 2019), the vendors had a total of 44,400 enrolled customers and 50,034 thermostats. As can be seen in Figure 2-1, the DR season started in 2019 with just under 10,000 enrollees. Growth was flat through the first two weeks of January, but then increased rapidly in late January. This growth was driven by recruiting efforts that took place over the course of the season for each thermostat vendor.

Figure 2-1: 2019 Season Program Participation



2.3.2 Participant Characteristics

Customers who signed up to participate in the Smart Therm Program are inherently different from customers who did not sign up to participate in the program or customers who were not targeted by SoCalGas marketing or thermostat vendors. Before the evaluation, specific customer segments were examined to observe how program participants differed from the overall population. Table 2-2 compares the portion of CARE customers who enrolled in the program to the overall population. Program participants were less likely to be CARE customers compared to the general residential population.

Table 2-2: Comparison of Program and Participation CARE Customers

CARE	% of Program Participants	% of SoCalGas Residential Customers
Yes	15.1%	28.5%
No	84.9%	71.5%
All	100%	100%

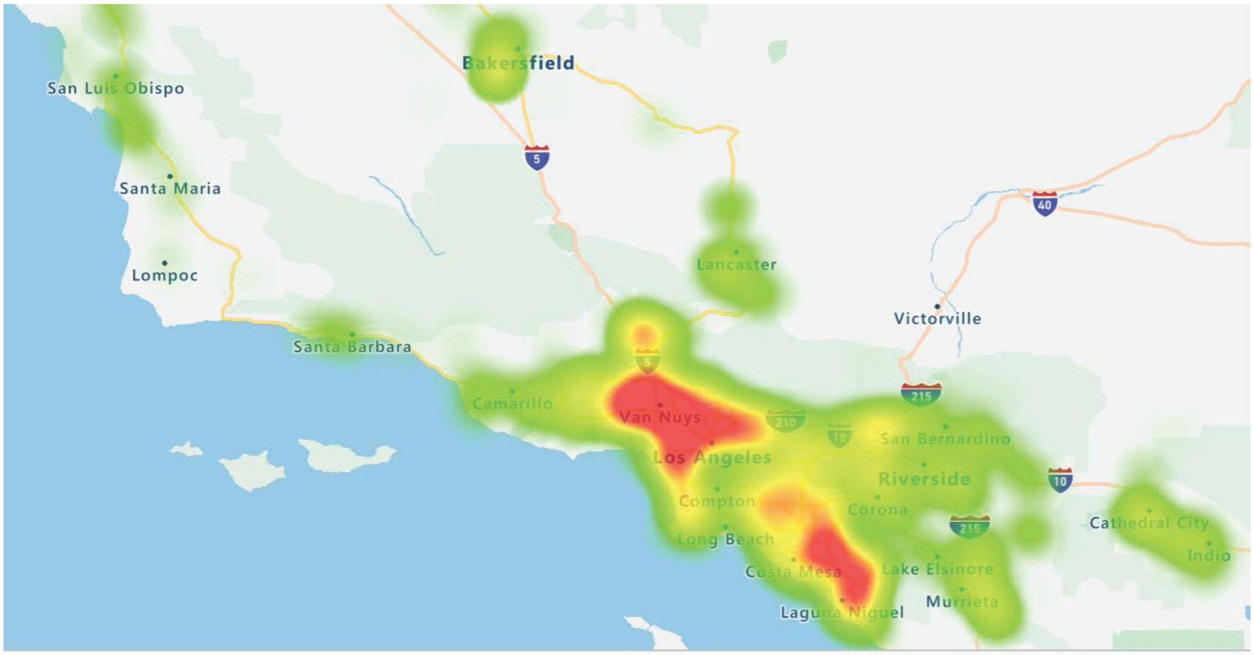
Table 2-3 compares the breakout of Smart Therm participant housing type to the SoCalGas residential customer population. Program participants were more likely to reside in a single family home compared to the general population.

Table 2-3: Comparison of Program and Population Housing Types

Housing Type	% of Program Participants	% of SoCalGas Residential Customers
Single Unit	78.3%	64.0%
2 or More Separate Units	2.3%	2.8%
2-4 Connected Units	5.3%	10.5%
5 or More Connected Units	14.0%	22.6%
Mobile Home Park	0.00%	0.02%
All	100%	100%

The location of program participants was also examined. Figure 2-2 shows a heat map of the locations of pilot participants throughout the SoCalGas service territory. The largest concentrations of customers are in the LA Basin and Orange County areas. The next largest concentration is in the Riverside, Palm Springs and Bakersfield areas.

Figure 2-2: Heat Map of Program Participant Location



2.4 Event Summary

During the 2018-2019 winter season, there were 29 events called over 24 days. The first event was called on January 2, 2019 and the last event was called on February 22, 2019. The majority of events were called in the morning (5:00 AM to 9:00 AM). However, on five days in February, both a morning and evening event (6:00 PM to 10:00 PM) were called. On days with multiple events, customers were called for either a morning event or an evening event. No customers participated in multiple events in a single day.

Table 2-4 provides an overview of the events called during the 2018-2019 season by date and time. In the next column, we list the number of smart thermostats that were activated for each event.

Table 2-4: Overall Event Summary

Event	Date	Event Window	Devices Targeted
1	2-Jan	5am – 9am	10,780
2	3-Jan	5am – 9am	10,789
3	4-Jan	5am – 9am	10,790
4	7-Jan	5am – 9am	10,808
5	15-Jan	5am – 9am	10,891
6	16-Jan	5am – 9am	10,887
7	17-Jan	5am – 9am	10,997
8	22-Jan	5am – 9am	11,141
9	23-Jan	5am – 9am	19,884
10	24-Jan	5am – 9am	22,934
11	4-Feb	5am – 9am	32,033
12	5-Feb	5am – 9am	33,241
13	6-Feb	5am – 9am	33,769
14	7-Feb	5am – 9am	34,178
15	8-Feb	5am – 9am	34,732
16	11-Feb	5am – 9am	32,469
17	11-Feb	6pm – 10pm	2,694
18	12-Feb	5am – 9am	24,992
19	12-Feb	6pm – 10pm	11,073
20	13-Feb	5am – 9am	25,477
21	13-Feb	6pm – 10pm	11,069
22	14-Feb	5am – 9am	25,813
23	14-Feb	6pm – 10pm	11,068
24	15-Feb	5am – 9am	25,825
25	15-Feb	6pm – 10pm	11,065
26	19-Feb	5am – 9am	37,528
27	20-Feb	5am – 9am	38,510
28	21-Feb	5am – 9am	38,547
29	22-Feb	5am – 9am	39,165

2.4.1 Event Participation

Table 2-5 depicts the participation for each event. Full participation refers to devices that were successfully programmed by the vendor, where the DR settings were in place for the entire event and the customer did not opt out. Approximately 51% of customers fully participated in an event on average. Partial participation refers to devices that only participated in a portion of the DR activation because they were either “off” or in a cooling mode for the rest of the time period, which was the case for approximately 1% of event participants on average. An opt-out refers to customers that overrode the DR event settings by manually changing their thermostat. Approximately 20% of event participants opted out on average. Other refers to a device not being accessible due to technical issues, the device being “off”, or the device being in a cooling mode. Approximately 27% of devices were not accessible for an event on average.

Overall, participation was relatively constant throughout all of the events, with an average of 51% of customers fully participating in events. The lowest level of full participation was 39%, which occurred on February 8 and February 11 for morning events. On these days, a larger number of thermostats were in the “Other” category, indicating that there may have been difficulties accessing the thermostats on those days. The highest level of full participation was 74%, which occurred on the February 11 evening event. It is worth noting however, that for that evening event a very low number of devices were targeted (2,694) and so this is likely why the participation was so much higher than average.

Overall, the average full participation rate of 51% was lower than the 2018 average full participation rate of 57%. There are several possible reasons for this. Events were called much earlier in the year and were called over a longer period of time compared to last year. Additionally, there were more than four times the number of customers enrolled in the program this year compared to last year, which resulted in essentially an entirely different participant population. The opt-out rates or thermostat settings of the new customers may differ from 2018 customers for the existing implementation strategy.

Table 2-5: Event Participation Summary

Date[6]	Time	Devices Targeted	Full Participation	Partial Participation[7]	Opt-Out Before[8]	Opt-Out During[9]	Other[10]
2-Jan	5am – 9am	10,780	51%	1%	1%	21%	26%
3-Jan	5am – 9am	10,789	51%	2%	1%	21%	25%
4-Jan	5am – 9am	10,790	52%	1%	1%	20%	26%
7-Jan	5am – 9am	10,808	51%	2%	1%	21%	25%
15-Jan	5am – 9am	10,891	53%	3%	1%	20%	23%
16-Jan	5am – 9am	10,887	55%	3%	1%	17%	24%
17-Jan	5am – 9am	10,997	56%	4%	1%	15%	24%
22-Jan	5am – 9am	11,141	50%	3%	1%	19%	27%
23-Jan	5am – 9am	19,884	46%	0%	0%	26%	28%
24-Jan	5am – 9am	22,934	53%	0%	1%	17%	29%
4-Feb	5am – 9am	32,033	50%	0%	0%	20%	30%
5-Feb	5am – 9am	33,241	50%	0%	0%	22%	28%
6-Feb	5am – 9am	33,769	47%	0%	0%	20%	33%
7-Feb	5am – 9am	34,178	47%	0%	0%	20%	33%
8-Feb	5am – 9am	34,732	39%	0%	0%	14%	47%
11-Feb	5am – 9am	32,469	39%	0%	0%	15%	46%
11-Feb	6pm – 10pm	2,694	74%	0%	0%	20%	6%
12-Feb	5am – 9am	24,992	52%	0%	0%	19%	29%
12-Feb	6pm – 10pm	11,073	50%	0%	0%	24%	26%
13-Feb	5am – 9am	25,477	55%	0%	0%	16%	29%
13-Feb	6pm – 10pm	11,069	49%	0%	0%	29%	22%
14-Feb	5am – 9am	25,813	57%	0%	0%	16%	27%
14-Feb	6pm – 10pm	11,068	53%	0%	0%	25%	22%
15-Feb	5am – 9am	25,825	56%	0%	0%	15%	29%
15-Feb	6pm – 10pm	11,065	51%	0%	1%	25%	23%
19-Feb	5am – 9am	37,528	51%	0%	0%	22%	27%
20-Feb	5am – 9am	38,510	52%	0%	0%	21%	27%
21-Feb	5am – 9am	38,547	54%	0%	0%	21%	25%
22-Feb	5am – 9am	39,165	49%	0%	1%	19%	31%

[6] Not all devices able to report on event participation summary statistics for events after Jan 22

[7] Participated in only part of the event because device was “off” or in cooling mode for the remainder of the event

[8] Customer overrode DR settings by manually changing the thermostat before the event started

[9] Customer overrode DR settings by manually changing the thermostat during the event. On average devices participated for 60 minutes.

[10] Device was not accessible because of technical issues, because device was “off”, or because device was in cooling mode

3 Load Impact Estimation Methodology

The primary challenge in estimating load impacts for DR programs such as the Smart Therm Program is estimating how much gas participants would have used during an event in the absence of SoCalGas dispatching the program. The estimated participants' usage in the absence of the event is referred to as the counterfactual or the reference load. This was not a randomized control trial, so the primary source of data used to develop reference loads is a matched control group. Control customers were selected from a pool of non-participant customers that passed several filters that were also applied to the program participants, and were statistically matched to program participants. The fundamental idea behind the matching process is to find customers who were not subject to DR events that have similar observable characteristics to those who were subject to DR events.

Once a suitable control group was created from a group of non-participants, the next step was to use a "difference-in-differences" analysis to estimate load impacts. Difference-in-differences helps to yield more precise estimates and can correct for observable differences in load not accounted for through matching. This calculation was done using a fixed-effects regression methodology, which reduces the standard error of the estimates. The underlying approach for difference-in-differences is comprised of the following:

- Measure gas demand for both treatment and control customers on proxy (similar non-event) days;

- Measure gas demand for both treatment and control customers on event days;

- Treatment effects are calculated by taking the difference between the treatment and matched control group in the event hours and subtracting any difference between the two groups in the event period hours on proxy days.

Additional details on the load impact estimation methodology including the selection of the matched control group and difference-in-differences regression model can be found in Appendix A.

4 Results

During the 2018-2019 winter, 29 events were called on 24 different days. All 29 events ran for four hours and were called either from 5 AM to 9 AM or from 6 PM to 10 PM[11]. The remainder of this section presents the load impacts for the Smart Therm program.

The results section focuses on the following three key metrics:

1. **Hourly impact:** The demand reduction for the average hour during the 4-hour event window. Hourly impacts were calculated by using the methodology described in Section 3.

2. **Event savings:** The total energy savings for the DR event across the full 4-hour event. Event savings were calculated by summing the four hourly impacts in the event window.

3. **Daily savings:** The net savings across the entire event day (CCF saved during the event minus CCF lost due to the “snap back” after the event). Daily savings were calculated by summing all 24 hourly impacts on the event day. In order to avoid including impacts that were not a result of the event, Nexant assumed that all hourly impacts after 3 PM were 0 CCF/hr for morning events, and all impacts before 12 PM were 0 CCF/hr for evening events. More information on this methodology can be found in Appendix A.

4.1 Load Impact Results

Table 4-1 summarizes the average hourly and aggregate hourly impacts for all customers that participated in the event. The schedule of event day, timing, and number of thermostats targeted can be found in Table 2-4. In total, there were twenty-four events called during the morning and five events called during the evening.

The average hourly impact during a morning event was .027 CCF/hr per participant representing a 15.1% load reduction from an average reference load of .181 CCF/hr. The aggregate hourly impact was a 0.093 MMcf/hr reduction during an average morning event hour. The average hourly impact during an evening event was .020 CCF/hr per participant representing a 15.5% load reduction from the average reference load of .134 CCF/hr. The aggregate hourly impact for an evening event was 0.019 MMcf/hr.

Table 4-2 summarizes the average event savings and aggregate event savings for all customers that participated in the event. The average event savings during a morning event was .110 CCF per participant representing a 15.1% load reduction from an average reference load of .751 CCF. The aggregate event savings was 0.372 MMcf during an average morning event. The average event savings during an evening event was .083 CCF per participant

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[11] A small subset of customers were part of a testing strategy that involved an 8-hour event with a 2-degree setback. Testing strategy results are reported in Section 4.4.

representing a 15.5% load reduction from the average reference load of .537 CCF. The aggregate event savings for an average evening event was 0.076 MMcf.

Table 4-3 summarizes the average daily savings and aggregate daily savings for all customers that participated in the event. The average daily savings on a day with a morning event was .061 CCF per participant leading to aggregate daily savings of 0.207 MMcf, or 2.2%. The average daily savings for a day with an evening event was .034 CCF per participant leading to aggregate daily savings of 0.031 MMcf, or 1.3%.

Time of day and corresponding levels of consumption, which are at least partially influenced by temperature, were large drivers of impact differences. Morning event impacts and reference loads were consistently higher than evening event impacts and reference loads, with higher reference loads generally associated with larger event impacts. There was a five degree temperature difference between the average morning event hour and the average evening event hour. The evening events also likely had reduced heating load due to the heat buildup in the home during the day as well as warmer event period temperatures.

Table 4-1: Average Hourly Impacts for All Events and Average Events[12]

Date	Event Window	Average Hourly Load w/o DR (CCF/hr)	Average Hourly Load w DR (CCF/hr)	Average Hourly Impact (CCF/hr)	Aggregate Hourly Impact (MMcf/hr)	Hourly Impact (%)	Avg. Event Temp. (F)
2-Jan	5am – 9am	0.215	0.179	0.036	0.032	16.86%	41.5
3-Jan	5am – 9am	0.210	0.176	0.034	0.030	16.06%	46.99
4-Jan	5am – 9am	0.205	0.167	0.038	0.034	18.57%	48.74
7-Jan	5am – 9am	0.143	0.110	0.033	0.030	23.22%	51.19
15-Jan	5am – 9am	0.155	0.119	0.035	0.032	22.89%	60.15
16-Jan	5am – 9am	0.134	0.100	0.034	0.031	25.29%	61.88
17-Jan	5am – 9am	0.103	0.072	0.030	0.028	29.71%	60.42
22-Jan	5am – 9am	0.176	0.158	0.018	0.029	9.99%	51.53
23-Jan	5am – 9am	0.180	0.153	0.026	0.050	14.62%	49.24
24-Jan	5am – 9am	0.157	0.132	0.024	0.056	15.49%	56.99
4-Feb	5am – 9am	0.130	0.100	0.030	0.083	23.00%	53.78
5-Feb	5am – 9am	0.155	0.123	0.032	0.090	20.57%	49.75
6-Feb	5am – 9am	0.217	0.189	0.028	0.081	13.00%	45.5
7-Feb	5am – 9am	0.219	0.192	0.027	0.078	12.22%	47.26
8-Feb	5am – 9am	0.208	0.180	0.029	0.084	13.72%	47.03
11-Feb	5am – 9am	0.212	0.186	0.026	0.072	12.14%	44.29
11-Feb	6pm – 10pm	0.146	0.112	0.034	0.008	23.43%	50
12-Feb	5am – 9am	0.193	0.169	0.024	0.052	12.31%	47.26
12-Feb	6pm – 10pm	0.124	0.106	0.017	0.016	14.05%	57.2
13-Feb	5am – 9am	0.131	0.106	0.025	0.054	18.74%	56.98
13-Feb	6pm – 10pm	0.151	0.128	0.023	0.021	15.26%	52.61
14-Feb	5am – 9am	0.101	0.080	0.021	0.047	20.79%	58.48
14-Feb	6pm – 10pm	0.127	0.106	0.021	0.019	16.45%	55.72
15-Feb	5am – 9am	0.136	0.110	0.026	0.060	19.35%	52.25
15-Feb	6pm – 10pm	0.133	0.112	0.021	0.020	16.05%	55.27
19-Feb	5am – 9am	0.217	0.192	0.025	0.079	11.71%	46.54
20-Feb	5am – 9am	0.208	0.179	0.029	0.091	13.98%	47.98
21-Feb	5am – 9am	0.186	0.156	0.030	0.095	16.22%	46.04
22-Feb	5am – 9am	0.219	0.189	0.031	0.103	14.06%	45.55
All Events							
Avg.	**AM**	**0.180**	**0.153**	**0.027**	**0.093**	**15.21%**	**49.72**
Avg.	**PM**	**0.134**	**0.113**	**0.021**	**0.019**	**15.46%**	**54.68**

[12] Customers who were in the implementation strategy test groups were excluded from the results on Feb 19 – Feb 21. For details on the implementation strategy results please see Section 4.4.

Table 4-2: Event Savings for All Events and Average Events[13]

Date	Event Window	Average Total Event Load w/o DR (CCF)	Average Total Event Load w DR (CCF)	Average Event Savings (CCF)	Aggregate Event Savings (MMcf)	Event Savings (%)	Avg. Event Temp. (F)
2-Jan	5am – 9am	0.861	0.716	0.145	0.129	16.86%	41.5
3-Jan	5am – 9am	0.841	0.706	0.135	0.120	16.06%	46.99
4-Jan	5am – 9am	0.822	0.669	0.153	0.136	18.57%	48.74
7-Jan	5am – 9am	0.573	0.440	0.133	0.119	23.22%	51.19
15-Jan	5am – 9am	0.618	0.477	0.142	0.127	22.89%	60.15
16-Jan	5am – 9am	0.536	0.401	0.136	0.123	25.29%	61.88
17-Jan	5am – 9am	0.410	0.288	0.122	0.111	29.71%	60.42
22-Jan	5am – 9am	0.703	0.633	0.070	0.117	9.99%	51.53
23-Jan	5am – 9am	0.718	0.613	0.105	0.202	14.62%	49.24
24-Jan	5am – 9am	0.626	0.529	0.097	0.223	15.49%	56.99
4-Feb	5am – 9am	0.519	0.399	0.119	0.333	23.00%	53.78
5-Feb	5am – 9am	0.621	0.494	0.128	0.361	20.57%	49.75
6-Feb	5am – 9am	0.870	0.757	0.113	0.324	13.00%	45.5
7-Feb	5am – 9am	0.875	0.768	0.107	0.311	12.22%	47.26
8-Feb	5am – 9am	0.833	0.719	0.114	0.336	13.72%	47.03
11-Feb	5am – 9am	0.849	0.746	0.103	0.286	12.14%	44.29
11-Feb	6pm – 10pm	0.585	0.448	0.137	0.033	23.43%	50
12-Feb	5am – 9am	0.771	0.676	0.095	0.206	12.31%	47.26
12-Feb	6pm – 10pm	0.494	0.425	0.069	0.064	14.05%	57.2
13-Feb	5am – 9am	0.523	0.425	0.098	0.216	18.74%	56.98
13-Feb	6pm – 10pm	0.603	0.511	0.092	0.085	15.26%	52.61
14-Feb	5am – 9am	0.406	0.322	0.084	0.186	20.79%	58.48
14-Feb	6pm – 10pm	0.507	0.423	0.083	0.077	16.45%	55.72
15-Feb	5am – 9am	0.545	0.440	0.105	0.239	19.35%	52.25
15-Feb	6pm – 10pm	0.532	0.447	0.085	0.078	16.05%	55.27
19-Feb	5am – 9am	0.868	0.766	0.102	0.316	11.71%	46.54
20-Feb	5am – 9am	0.833	0.716	0.116	0.362	13.98%	47.98
21-Feb	5am – 9am	0.743	0.622	0.120	0.381	16.22%	46.04
22-Feb	5am – 9am	0.878	0.755	0.123	0.411	14.06%	45.55
All Events							
Avg.	**AM**	**0.721**	**0.611**	**0.110**	**0.373**	**15.21%**	**49.72**
Avg.	**PM**	**0.537**	**0.454**	**0.083**	**0.076**	**15.46%**	**54.68**

[13] Customers who were in the implementation strategy test groups were excluded from the results on Feb 19 – Feb 21. For details on the implementation strategy results please see Section 4.4.

Table 4-3: Daily Savings for All Events and Average Events[14]

Date	Event Window	Average Total Daily Load w/o DR (CCF)	Average Total Daily Load w DR (CCF)	Average Daily Savings (CCF)	Aggregate Daily Savings (MMcf)	Daily Savings (%)	Avg. Event Temp. (F)
2-Jan	5am – 9am	3.246	3.243	0.003	0.003	0.10%	41.5
3-Jan	5am – 9am	2.944	2.927	0.018	0.016	0.61%	46.99
4-Jan	5am – 9am	2.806	2.774	0.032	0.028	1.13%	48.74
7-Jan	5am – 9am	2.297	2.219	0.078	0.069	3.39%	51.19
15-Jan	5am – 9am	2.799	2.727	0.072	0.064	2.56%	60.15
16-Jan	5am – 9am	2.167	2.065	0.102	0.092	4.72%	61.88
17-Jan	5am – 9am	1.812	1.666	0.145	0.132	8.01%	60.42
22-Jan	5am – 9am	2.392	2.342	0.050	0.082	2.07%	51.53
23-Jan	5am – 9am	2.238	2.165	0.073	0.140	3.26%	49.24
24-Jan	5am – 9am	1.790	1.721	0.069	0.159	3.87%	56.99
4-Feb	5am – 9am	2.346	2.224	0.122	0.340	5.20%	53.78
5-Feb	5am – 9am	2.818	2.702	0.116	0.329	4.13%	49.75
6-Feb	5am – 9am	3.287	3.232	0.055	0.157	1.67%	45.5
7-Feb	5am – 9am	3.034	2.987	0.047	0.136	1.54%	47.26
8-Feb	5am – 9am	2.791	2.731	0.060	0.176	2.14%	47.03
11-Feb	5am – 9am	2.962	2.898	0.064	0.177	2.15%	44.29
11-Feb	6pm – 10pm	3.322	3.271	0.051	0.012	1.54%	50
12-Feb	5am – 9am	2.540	2.506	0.035	0.075	1.36%	47.26
12-Feb	6pm – 10pm	2.961	2.916	0.045	0.041	1.52%	57.2
13-Feb	5am – 9am	2.417	2.327	0.089	0.197	3.69%	56.98
13-Feb	6pm – 10pm	2.711	2.703	0.008	0.008	0.31%	52.61
14-Feb	5am – 9am	1.966	1.896	0.070	0.156	3.58%	58.48
14-Feb	6pm – 10pm	2.207	2.146	0.061	0.056	2.75%	55.72
15-Feb	5am – 9am	2.249	2.169	0.080	0.181	3.55%	52.25
15-Feb	6pm – 10pm	2.586	2.567	0.019	0.017	0.72%	55.27
19-Feb	5am – 9am	3.077	3.035	0.042	0.131	1.37%	46.54
20-Feb	5am – 9am	3.323	3.253	0.070	0.217	2.10%	47.98
21-Feb	5am – 9am	3.257	3.168	0.088	0.280	2.71%	46.04
22-Feb	5am – 9am	3.075	3.027	0.049	0.162	1.58%	45.55
All Events							
Avg.	**5am – 9am**	**2.721**	**2.660**	**0.061**	**0.207**	**2.24%**	**49.72**
Avg.	**6pm – 10pm**	**2.651**	**2.618**	**0.034**	**0.031**	**1.27%**	**54.68**

[14] Customers who were in the implementation strategy test groups were excluded from the results on Feb 19 – Feb 21. For details on the implementation strategy results please see Section 4.4.

4.1.1 Event Day Load Shapes and Snap Back

Figure 4-1 and Figure 4-2 show the full 24-hour profile for average customer load impacts, reference loads, and observed loads for the average morning and evening event day. While there were five days that had both morning and evening events called across the different thermostats, no set of customers was called for both event windows within a single event day. Therefore, there is no load profile for both a morning and evening event taking place in a single day, as no customer experienced this type of event in the 2018-2019 DR season. Morning event windows had the highest overall reference load and highest overall impacts with the largest impact occurring in the first hour of the morning event. Evening events had a much lower reference load and lower impacts.

In the hour following both morning and evening events, there is what is referred to as “snap back”, which is when customer gas usage is higher after an event than would be expected if an event had not taken place. After the event, the thermostat temperature is returned to its pre-event temperature. In order to increase the temperature in the home to the non-event temperature, the HVAC system has to run more consistently for up to the first hour following the event (or longer). This can result in increased consumption in the hours following an event compared to what would typically be expected on a similar non-event day. The average snap back in the hour following morning events was 0.033 CCF/hr, with the load of the average participant 29% greater than customers that did not participate in the event. The 2019 morning event snap back is 15% lower than the 2018 morning event snap back, which is discussed in more detail in section 4.3.

The average snap back in the hour following evening events was 0.035 therms, representing a 35% load increase compared to customers that did not participate in the event. For an evening event, the snap back was large enough that it shifted the evening peak for DR participants from 7-8 PM to 10-11 PM. However, the 10-11 PM peak created by DR customers is smaller than the counterfactual peak, 0.136 CCF/hr versus 0.141 CCF/hr for the average customer between 7 and 8 PM. The 2019 evening event snap back is twice the size of the 2018 evening event snap back, which is correlated with the large event savings seen during 2019 evening events compared to 2018 evening events. Last year’s evening snap back also created a DR participant peak that was higher than the counterfactual peak, while this year’s snap back does not. A comparison of 2019 impacts to 2018 impacts is described in more detail in section 4.3.

Figure 4-1: Load Shape on Average Morning Event Day

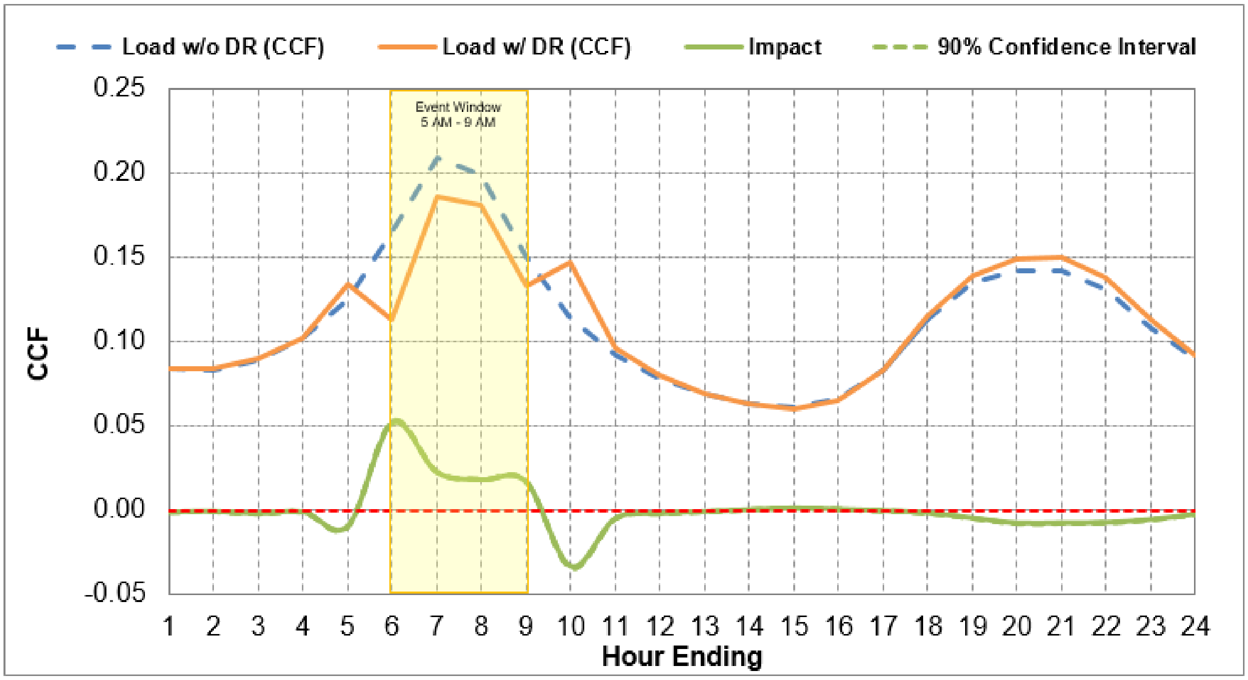
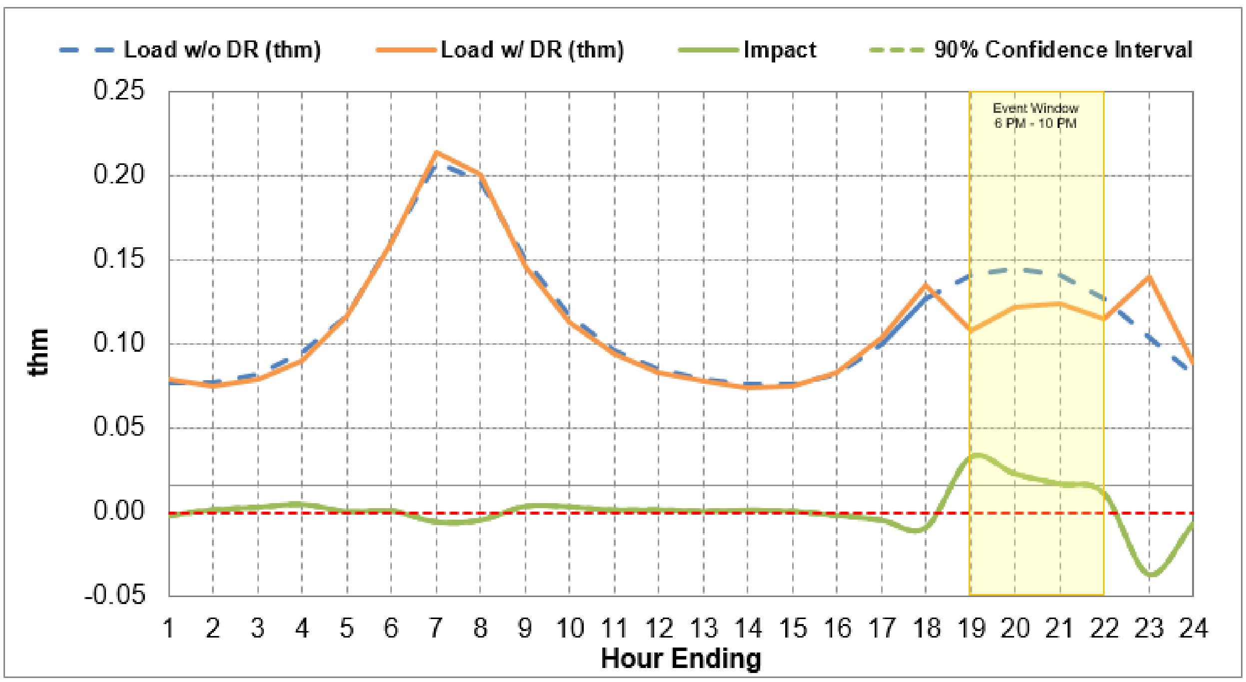


Figure 4-2: Load Shape Average Evening Event Day

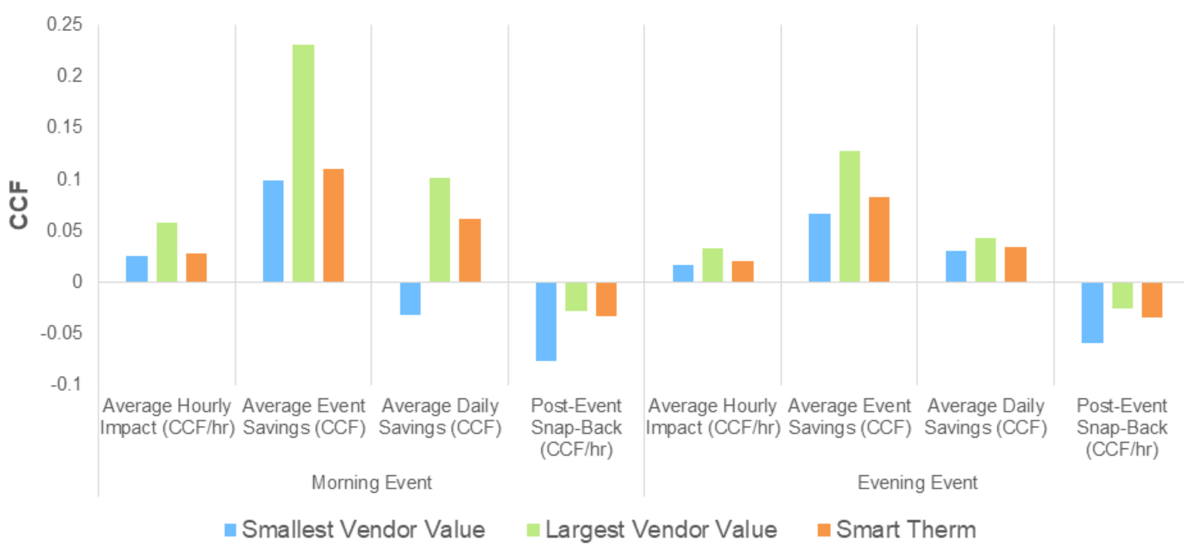


4.2 Vendor Comparison

In addition to evaluating program-level results, Nexant evaluated load impact results for each vendor. Figure 4-3 compares the program results to the range of vendor-specific load impacts, with the green bar representing vendors with the largest savings, blue representing the smallest savings, and orange representing the program-level savings summarized in Section 4.1. For the average morning event, some vendors were able to achieve more than twice the average hourly impacts and event savings compared to the overall program. Daily savings varied greatly by vendor, with some vendors experiencing negative daily savings and other vendors experiencing daily savings much larger than program level daily savings. For the average evening event, there was less variation between vendors, although some achieved large event savings and hourly impacts relative to the overall Smart Therm program. For both morning and evening events, some vendors experienced significantly larger snap backs compared to the overall program. In the evening, the increase in gas consumption for some vendors was large enough that it created a new DR participant evening peak that was significantly larger than the counterfactual 7-8 PM peak. However, that was not the case for the Smart Therm program as a whole.

Several different reasons could explain the variation we see in event savings, snap back, and daily savings. The first could be the different implementation strategies each vendor used. Vendor strategies include 4-degree setback, 3-degree setback, and up to 3-degree setback based on a customer's comfort setting. Each strategy yielded different levels of load reduction and snap back, which affected overall daily savings. There was also variation depending on the size of the average customer, with the vendor with the largest average customer also experiencing the largest event savings. Finally, it is important to note that some vendors had very few participants and were evaluated for relatively few events. Accordingly, some of the vendor-specific results below (such as the negative daily savings) are not statistically significant and could change next year when more data is available.

Figure 4-3: Vendor Comparison of Metrics for Average Morning and Evening Event



4.3 Comparison to 2018 Results

In 2018, 9,267 customers participated in SoCalGas' demand response program. A total of 13 events were called over 9 days, with two days in which all vendors were called for a morning-only event and two days in which all vendors were called for an evening-only event. Only days with all vendors participating in morning- or evening-only events have been included in the year-over-year comparison depicted below. Including days where only a single vendor was called or days where customers participated in both the morning and evening would not be an appropriate comparison to the current evaluation.

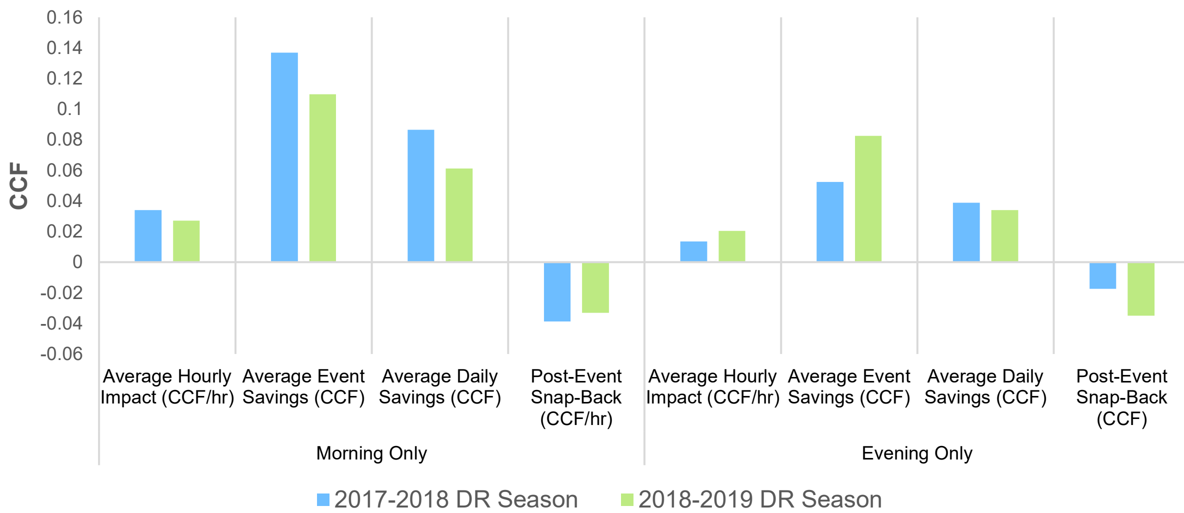
Figure 4-4 compares the results from the 2018 evaluation to the current evaluation for the average morning and evening event. For the average morning event, the average hourly impact and average event savings are approximately 20% lower compared to 2018, and the daily savings are about 30% lower than in 2018. There are several possible reasons for these differences. First, this comparison is based on an average over 24 events (2019) to an average over 2 events (2018), which means that each event day in 2018 carries significantly more weight than each event day in 2019. Second, 2019 morning events were generally called earlier in the season compared to 2018, with 40% of 2019 morning events called in January compared to all 2018 morning events called at the end of February or early March. Finally, the customer mix for morning events changed substantially in 2019, with enrollment in the program increasing by over 300%. Compared to 2018 participants, new participants were more likely to be enrolled in CARE and on average had lower annual consumption levels than 2018 participants. The new customers and their lower average gas consumption levels affected morning event impacts by reducing the amount of consumption available for curtailment. Additionally, as participation grew, the share of participants represented by the vendor with the largest event savings declined, which reduced the average impacts of the overall program.

Unlike the morning events, evening events largely contained customers who participated in the program in both winters and were only called towards the end of February. In the evening, the average hourly impact and average event savings increased by about 50% in 2019 compared to the 2018 impacts. This is likely due to the shift of the evening event to a later time, which coincided better with the evening peak for residential customers. Despite the improved event performance in 2019, the average daily savings decreased, which is possibly driven by the larger snap back for evening-only events in 2019 compared to 2018.

Overall, the daily savings this year were lower than 2018 for both morning and evening events. However, it is important to note that while last year's daily savings were not statistically significant, due in part to a relatively small number of customers and few events, this year the results are statistically significant. Therefore, with the larger participant population and larger number of events, this year's results are likely more representative of what this program is capable of delivering across all metrics with the current implementation strategy[15].

[15] It should be noted that, as seen in Sections 4.2 and 4.4, implementation strategies do affect impacts. Therefore, if vendors change their implementation methods, as some plan to do in the upcoming DR season, it is likely that these impacts will change.

Figure 4-4: Year-Over-Year Comparison of Metrics



4.4 Strategy Implementation Results

As stated in Section 2.2, SoCalGas tested two new strategies during the 2019 season. These strategies were implemented from February 19 through February 21 in order to test their effectiveness. SoCalGas selected a subset of Smart Therm customers and randomly assigned them to one of three groups:

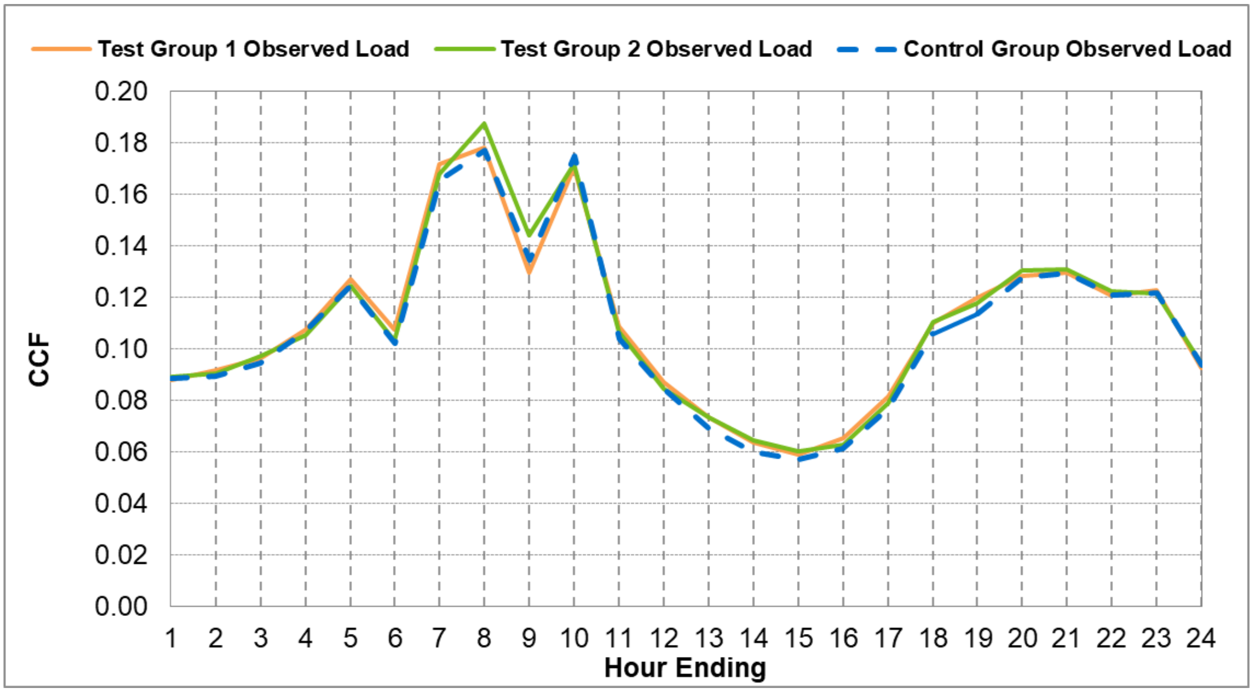
1. Control Group – these customers received the same implementation strategy they had received the entire DR season

2. Treatment Group #1 – These customers participated in a 4-hour event with a 3-degree setback. The event lasted from 5 AM – 9 AM, and then customers were randomly rolled off the event from 9:00 AM – 9:30 AM.

3. Treatment Group #2 – These customers participated in an 8-hour event with a 2-degree setback. The event lasted from 5 AM – 1 PM.

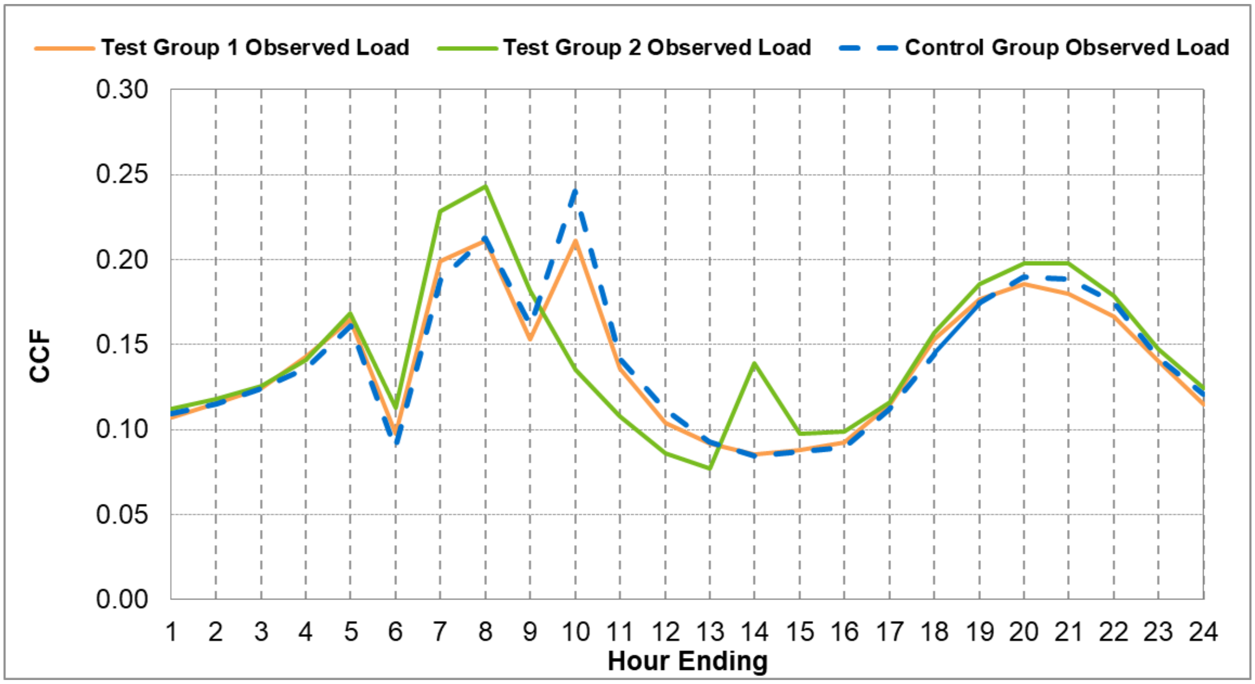
Each group contained approximately 900 customers, for a total of approximately 2,700 customers participating in the implementation strategy tests. In order to ensure that the control group was a valid representation of the other two test groups, Nexant first compared the behavior of each group on event days when all customers received the same implementation strategy. Figure 4-5 plots the observed load from the three groups on the average morning event day when all customers received the same implementation strategy. Overall, the three groups behaved similarly on event days where they received the same implementation strategy.

Figure 4-5: Comparison of Control Group and Test Groups on non-Test Event Days



Nexant then compared the behavior of each group on the three test days to determine the impact of the different implementation strategies. Figure 4-6 shows the observed load of the three groups on the average morning event day when the different strategies were tested. Overall, Test Group #2 had the highest observed load from 5 AM to 9 AM, 19% higher than the control group on average, and the lowest observed load from 9 AM to 1 PM, 27% lower than the control group on average. Test group #1 had an observed load almost identical to that of the control group from 5 AM to 9 AM, but a snap back 12% lower than the control group in the hour following the event. Over the course of the entire day, the control group consumed 3.39 CCF, Test Group #1 consumed 3.36 CCF, and Test Group #2 consumed 3.48 CCF. So, while both implementation strategies were able to reduce post-event snap back, Test Group #1 saw very little change in daily consumption relative to the control group and Test Group #2 saw higher daily consumption relative to the control group.

Figure 4-6: Comparison of Control Group and Test Groups on Test Event Days



5 Conclusions and Recommendations

Figure 5-1 provides a summary of the 2018-2019 winter Smart Therm Program hourly event impacts for each event and for the average morning and evening event. The average hourly load reduction for a morning event was 0.027 CCF/hr per participant leading to an aggregate reduction of 0.093 MMcf/hr, or 15.1%. The average hourly load reduction for an evening event was 0.020 CCF/hr, leading to an aggregate reduction of 0.019 MMcf/hr, or 15.5%. Morning events also consistently had larger impacts than evening events, with the exception of February 11 when relatively few customers were called for an evening event and had much higher than average participation.

Figure 5-1: Winter 2018-2019 Hourly Load Impact Estimates

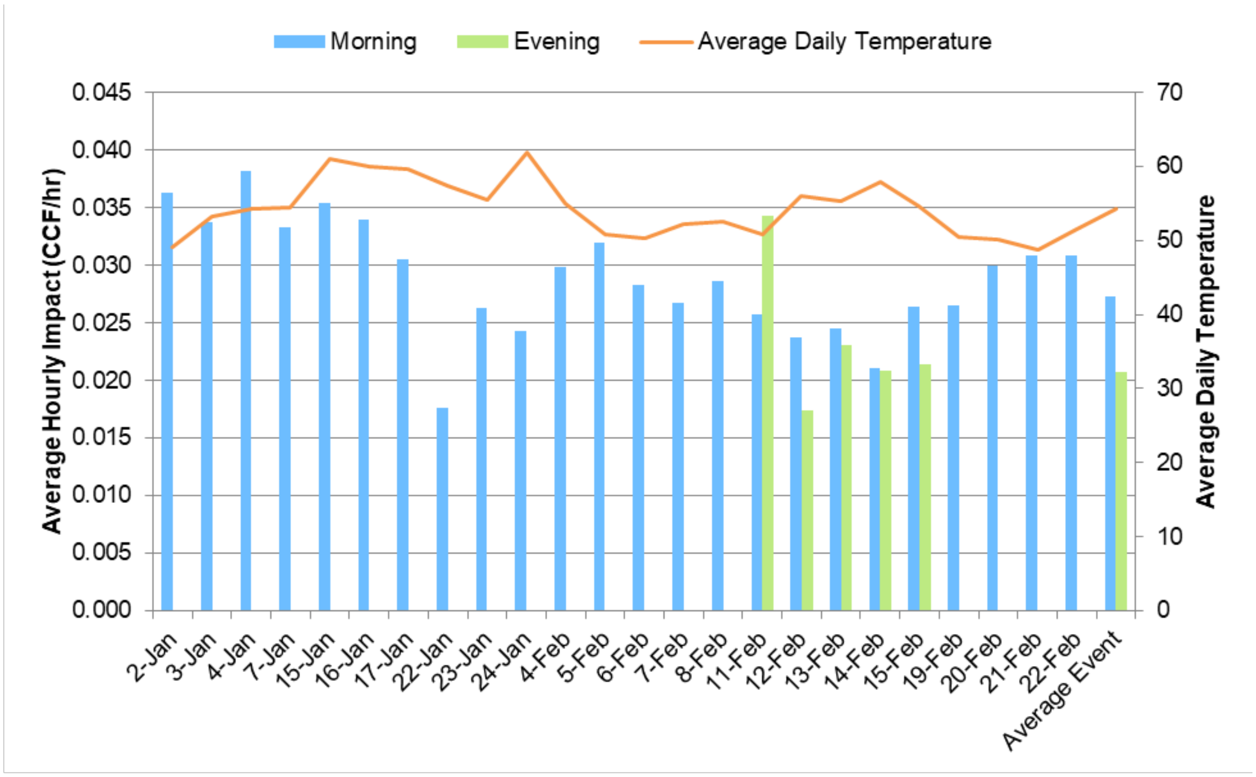


Figure 5-2 provides a summary of 2018-2019 event savings for each event and for the average morning and evening event. The average event savings for a morning event was 0.110 CCF per participant leading to aggregate event savings of 0.372 MMcf. The average event savings for an evening event was 0.083 CCF per participant, leading do aggregate event savings of 0.076 MMcf.

Figure 5-2: Winter 2018-2019 Event Savings Estimates

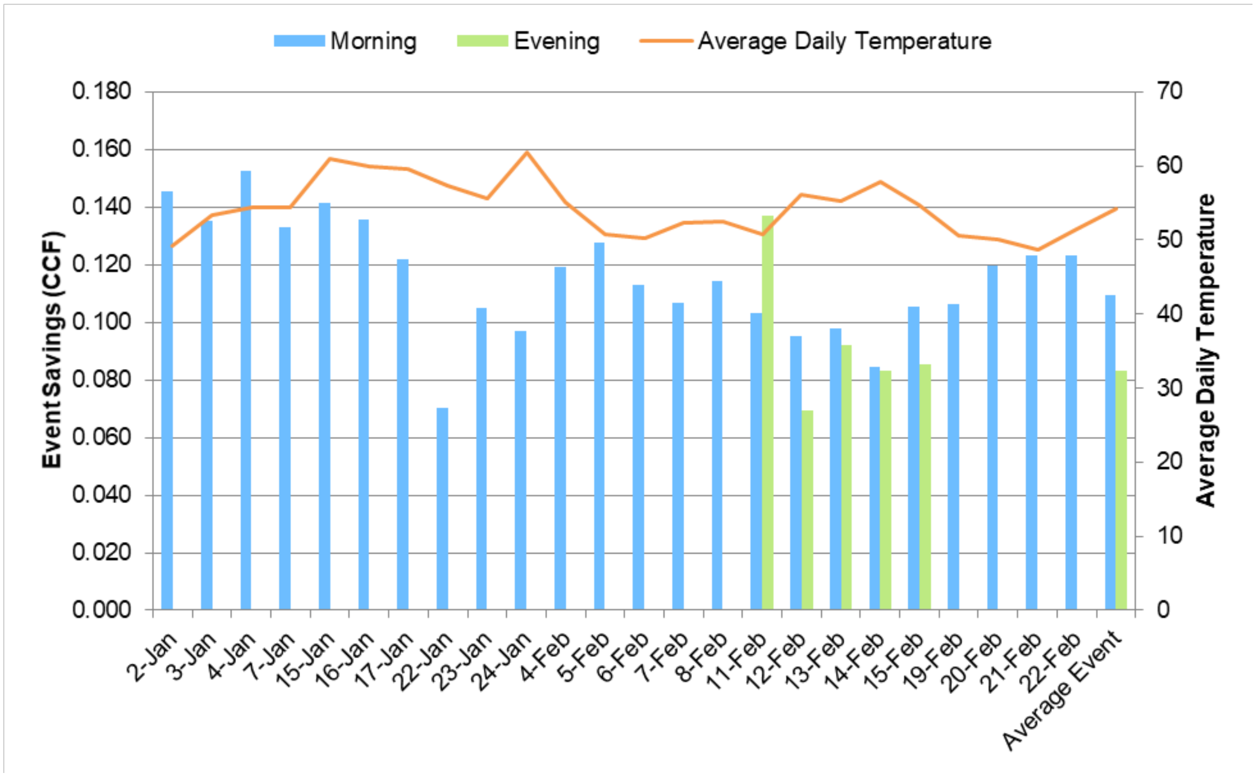
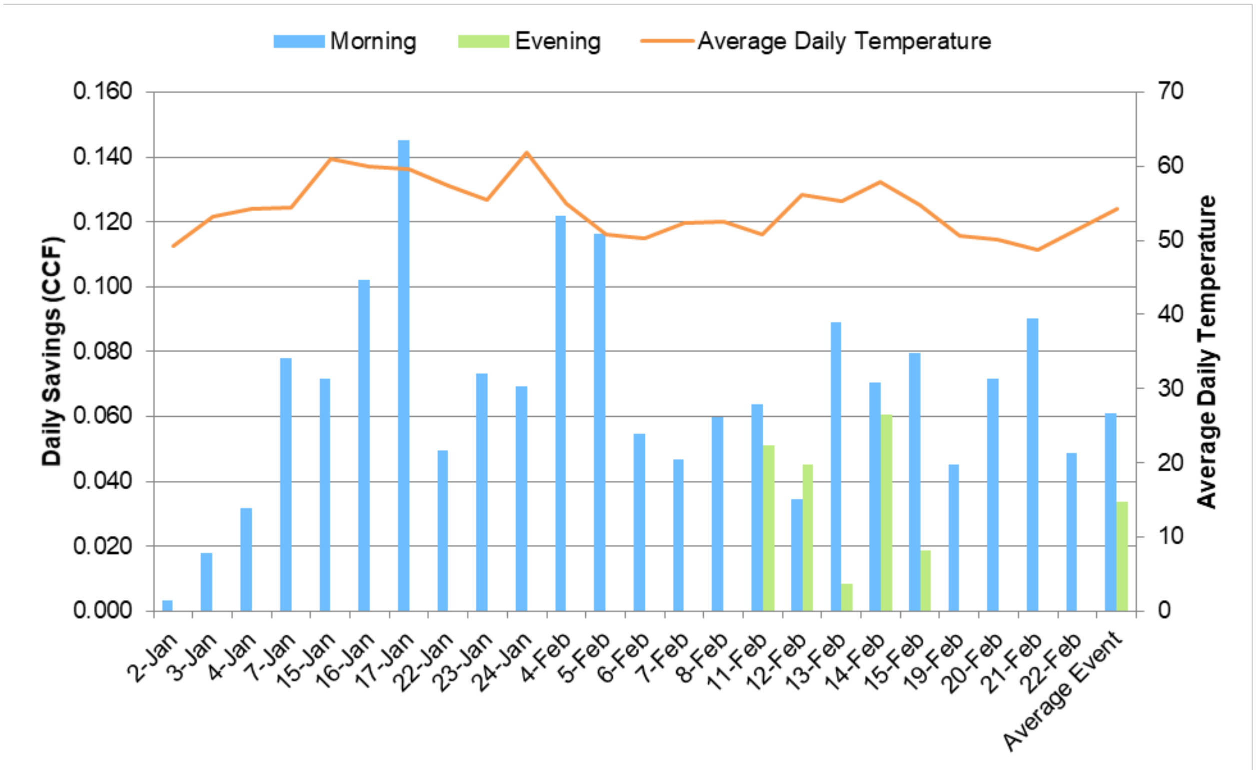


Figure 5-3 provides a summary of 2018-2019 net daily savings for each event and for the average morning and evening event. Overall, we see more variation between the events for daily savings than we see for hourly impacts or event savings. The average daily savings for a morning event was 0.061 CCF per participant leading to aggregate savings of 0.207 MMcf, or 2.24%. The average daily savings for an evening event was 0.034 CCF per participant leading to aggregate daily savings of 0.031 MMcf, or 1.27%.

Figure 5-3: Winter 2018-2019 Daily Savings Estimates



The SoCalGas Thermostat program is one of the first, if not the first, natural gas based demand response programs in the US. It has proven that smart thermostats can be used to reduce demand for natural gas during targeted periods of time in the morning and the evening and can achieve net daily savings as a result of calling these events. However, the snap back following the event when a customer's preferred temperature settings are restored can be quite significant, and greatly reduces net daily CCF savings when compared to event savings.

From a technical perspective, it's clear the program met the objectives of significantly reducing gas consumption during specific windows of time. However, due to gas usage snap backs in the hours following events, the net daily CCF savings that resulted from this program were only in the 1% to 2% range depending on the timing of the event.

Appendix A Load Impact Methodology Details

A.1 Selection of Matched Control Group

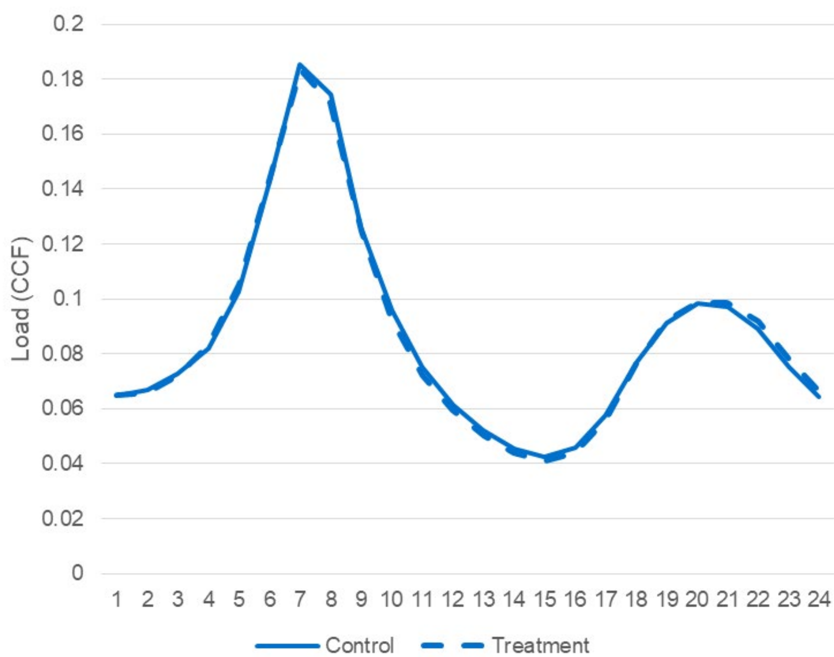
Customers who signed up to participate in the Smart Therm program are inherently different from customers who did not sign up to participate in the Smart Therm program or customers who were not targeted by the thermostat vendors. For this reason, a control group must be constructed using statistical matching. It is possible that the customers who enrolled in the Smart Therm program had particular characteristics that made them more likely to enroll than customers who did not enroll or customers who were not targeted to enroll. This is particularly important when studying early adopters of a new technology such as smart thermostats who may have very different gas consumption patterns from those of the rest of the population. This type of behavior introduces selection bias because the difference in usage between the two groups caused by characteristics differences could be mistaken as the impact of treatment. A matched control group is the primary source for reference loads which are used to estimate impacts. The method used to assemble the matched control group is designed to ensure that the control group load on event days is an accurate estimate of what load would have been among Smart Therm customers on event days if an event hadn't taken place.

Nexant selected the control groups using propensity score matching to find residential SoCalGas customers who are non-DR program participants with load shapes most similar to those of Smart Therm participants. In this procedure, a probit model is used to estimate a score for each customer based on a set of observable variables that are assumed to affect the decision to join the Smart Therm program. A probit model is a regression model designed to estimate probabilities—in this case, the probability that a customer would enroll in the Smart Therm program. The score can be interpreted two different ways. First, the propensity score can be thought of as a summary variable that includes all the relevant information in the observable variables about whether a customer would choose to participate in Smart Therm. Each customer in the DR program population was matched with a customer in the non-DR population that has the closest propensity score. The second way to think of the propensity score is as the probability that a customer will join the Smart Therm program based on the included independent variables. Thinking of it this way, each customer in the control group was matched to a Smart Therm customer with a similar probability of joining the Smart Therm program given the observed variables. Nexant performed the match within four clusters that grouped customers based on their load shape similarity. In other words, the match was conducted separately for Smart Therm customers that had load shapes similar to one-another.

In order to select the probit model used to find the best match for each treatment customer, "out of sample" testing was performed to evaluate several different probit model specifications. Out of sample testing involves running each of the different model specifications using all but one of the proxy days, leaving the unused proxy day to test how well the model performed. By leaving a different proxy day out each time the matching selection is run, one is able to see how well the matches look on a day that was not used to select the match. During this process, sixteen different model specifications were tested using different observable variables including usage during event hours, average total daily usage, and usage from 12pm to 9pm. For each of the eleven models six different “calipers” were tested. Calipers set a maximum threshold of how large the difference in propensity scores can be for a matched pair. During the matching process, the treatment customers are matched to the control customer who has the most similar propensity score to them. Additionally, treatment customers can only be matched to a control customer in the same load shape cluster. If the difference between a treatment customer and control customer’s propensity score is higher than the set caliper, the treatment customer will not be matched. Therefore, a caliper sets the standard for how close the matched pairs need to be. In order to find the closest control customer matches, the Smart Therm customers were split out by vendor to find the optimal probit model for each vendor. This provided much closer matches for each of the vendor customers.

Figure A-1 shows the results of the matched control group for Smart Therm participants. The customers match very well to their matched control group on proxy days. This is expected due to the large number of participants in the program.

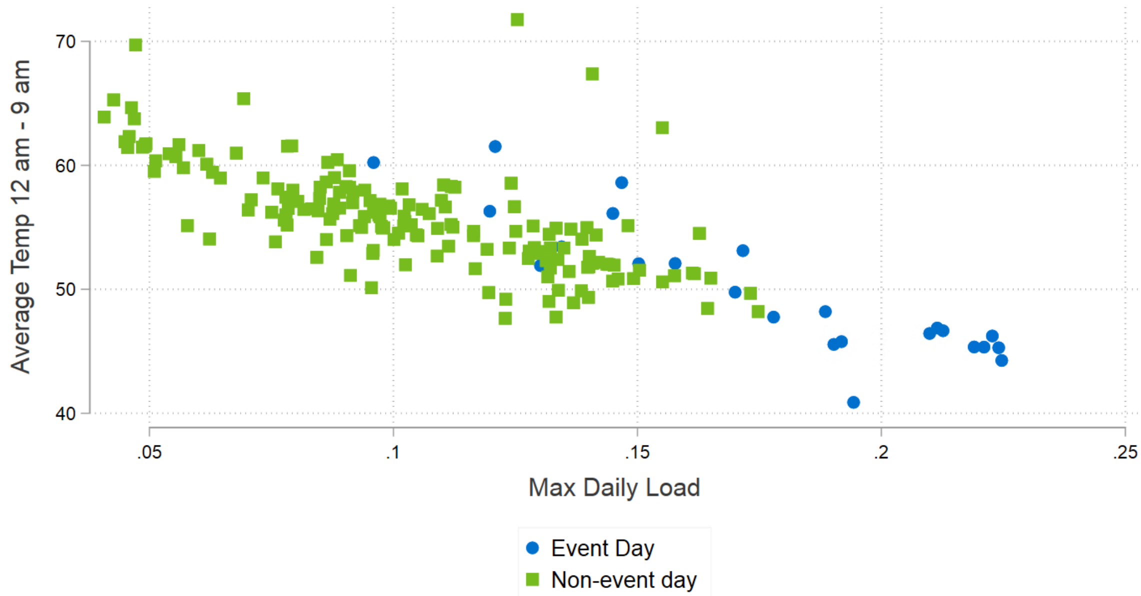
Figure A-1: Hourly Average Demand for All Customers on Proxy Days



Proxy Day Selection

As stated above, in order to validate the matching model to ensure customers would behave similarly on an event day, Nexant uses out-of-sample testing to match customers on event-like nonevent days, referred to here as “proxy days”. To select these days, Nexant looks at the load of the control pool and different temperatures metrics on event days and non-event days. Non-event days with a similar combination of load and temperature conditions to event days are then selected as proxy days for out-of-sample testing. Figure A-2 shows the maximum daily load for the average control customer plotted against the average temperature from 12 AM – 9 AM for each event day in the 2018-2019 DR season and each non-event day for the 2017-2018 and 2018-2019 winters. Although there are two seasons from which Nexant could select proxy days, there are no non-event days that are similar to the relatively cold and high load conditions that are seen on the event days this season. As a result, even though the treatment and control customers match up well on more moderate days it is difficult to determine if their similarities carry over to the more extreme event days. This reduces the overall accuracy of the control group when estimating load impacts on event days. While program goals and operational needs should drive event dispatch, we note that withholding a few very cold days for evaluation purposes will provide key data points to further strengthen the Smart Therm evaluator's ability to develop credible ex post estimates.

Figure A-2: Average Temperature from 12-9 AM vs. Max Daily Load



A.2 Difference-in-Differences Regression Models

After a matched control group was created, program impacts were estimated using a difference-in-differences regression model. This methodology is based on the assumption that the program impact is equal to the difference in usage between the treatment and the control groups during the event period, minus any pre-existing difference between the two groups. When using difference-in-differences, the matched control group does not need to perfectly match the treatment group on the proxy days. Any differences that may be due to observable differences in load not accounted for through matching will be netted out by the differencing. It is a reasonable assumption that any unobservable differences between the treatment and the control groups during the event period hours on proxy days stay the same during the DR event hours. Therefore any further difference between the groups in the DR event hours is assumed to be the impact of treatment. This regression model is shown in Equation A-1 below:

Equation A-1: Difference-in-Differences Models

$$thm_{i,t} = a + b \cdot Treatment_i + c \cdot Event_t + d \cdot (Treatment_i \cdot Event_t) + u_t + v_i + \varepsilon_{i,t} \text{ for } i \in \{1, \dots, n_i\} \text{ and } t \in \{1, \dots, n_t\}$$

Variable	Definition
i, t, n	Indicate observations for each individual *i*, date *t* and event number *n*
a	The model constant
b	Pre-existing difference between treatment and control customers
c	The difference between event and proxy days common to both treatment and control group members[1]
d	The net difference between treatment and control group customers during event days–this parameter represents the difference-in-differences
u	Time effects for each date that control for unobserved factors that are common to all treatment and control customers but unique to the time period
v	Customer fixed effects that control for unobserved factors that are time-invariant and unique to each customer; fixed effects do not control for fixed characteristics such as air conditioning that interact with time varying factors like weather
ε	The error for each individual customer and time period
$Treatment$	A binary indicator or whether or not the customer is part of the treatment or control group
$Event$	A binary indicator of whether an event occurred that day–impacts are only observed if the customer is enrolled in Smart Therm (*Treatment* = 1) and it was an event day

The model was estimated using both event days and proxy days, which are nonevent days with similar weather conditions and system load usage as days when events are called. The difference in loads between treatment and control customers for the event period hours on proxy days is subtracted from the differences on DR event hours to adjust for any differences between the treatment and control groups due to random chance.

As an extra validation, the simple difference in loads between treatment and control customers during event hours on event and proxy days was calculated to ensure that the regression model produces a similar output. The regression model also reduces the standard errors of the impact estimates compared to those that can be calculated from a simple difference in loads.

A.3 Calculating Daily Savings

Due to the lack of proxy days that mirrored event day conditions, as described in section A.1, when estimating hourly load impacts across all 24 hours of the event day there was often differences between the Smart Therm participant load and the reference load. Figure A-3 depicts these load shapes during an average morning event, as shown in section 4. In the evening we can see that there are differences between the reference load and observed load in the evening, several hours after the two groups came together in the middle of the day. For the purpose of calculating daily savings, it was assumed that these differences were not due to "treatment effects", or an event being called in the morning. This means that for morning events, it was assumed that after 3 PM the two groups had equal amounts of load each hour and for evening events, it was assumed that before 12 PM the two groups had equal amounts of load

[1] In practice, this term is absorbed by the time effects, but it is useful for representing the model logic.

for each hour. Figure A-4 illustrates what this assumption looks like for the average morning event.

Figure A-3: Load Shape on Average Morning Event Day

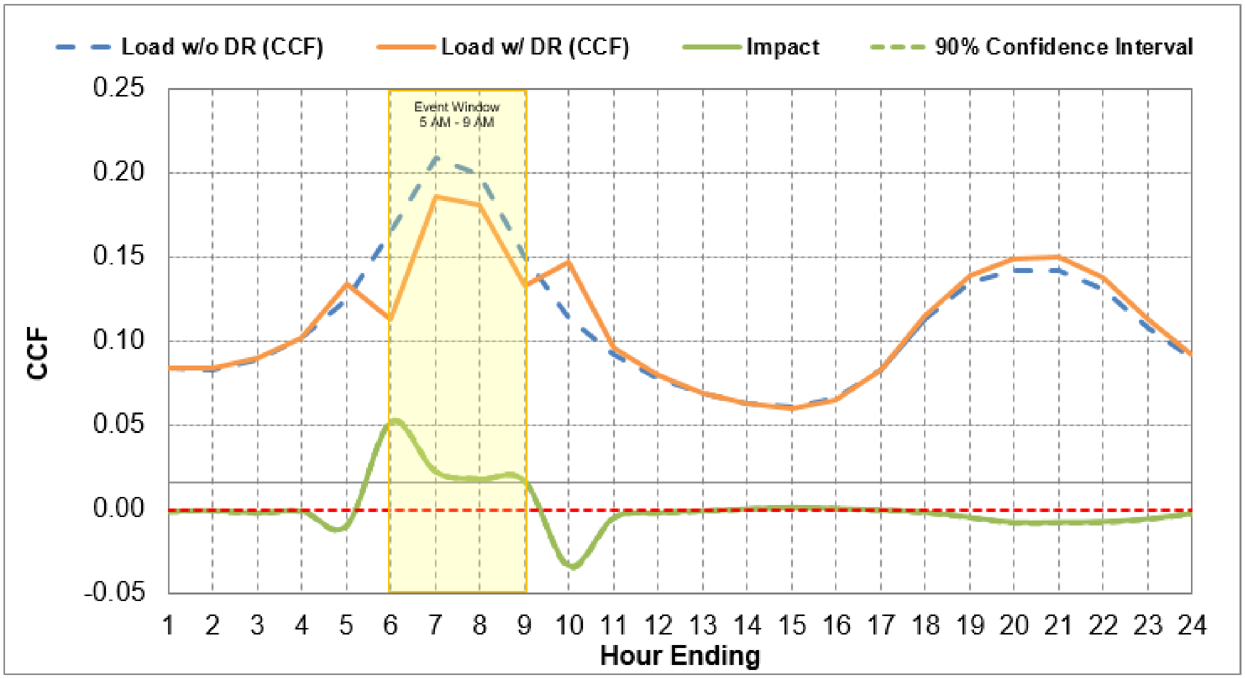
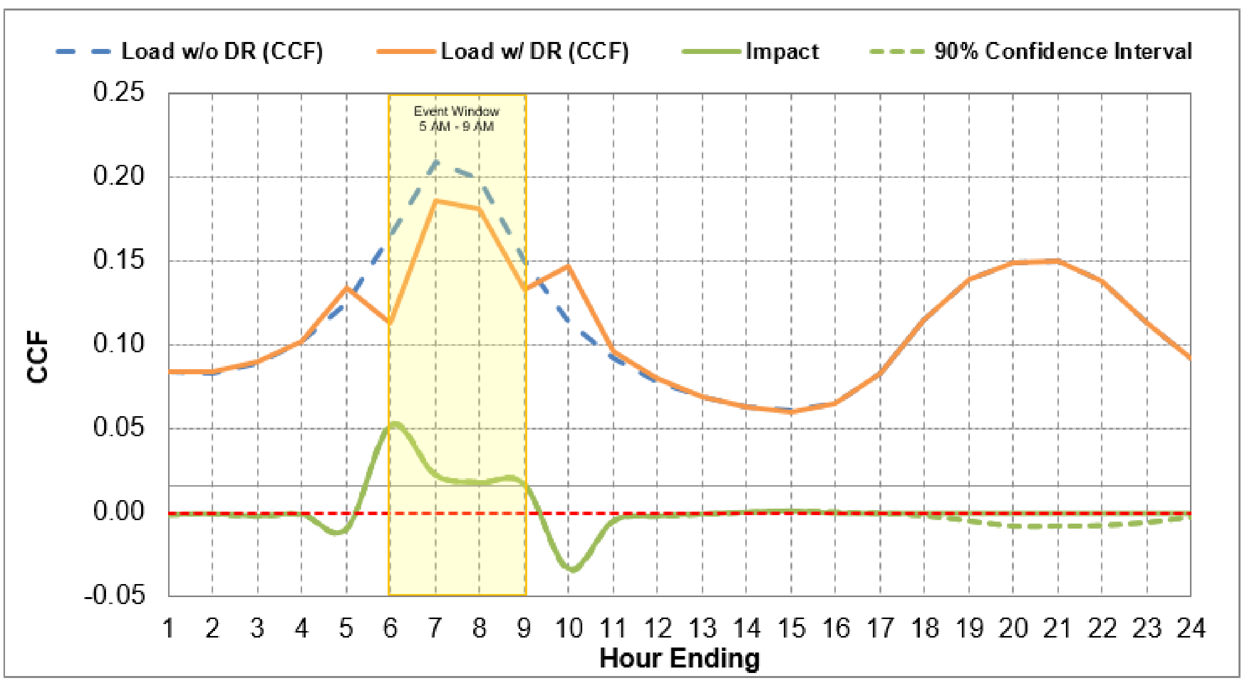


Figure A-4: Load Shape on Average Morning Event Day with Daily Savings Adjustment



Appendix B Results (thm)

Table B-2, and Table B-3 present the results from section 4 in therms rather than CCF. All results were originally calculated in therms, and then divided by a conversion factor of 1.03 to get the results in CCF.

Table B-1: Average Hourly Impacts for All Events and Average Events (thm)

Date	Event Window	Average Hourly Load w/o DR (thm)	Average Hourly Load w DR (thm)	Average Hourly Impact (thm)	Aggregate Hourly Impact (thm)	Hourly Impact (%)	Avg. Event Temp. (F)
2-Jan	5am – 9am	0.222	0.184	0.037	333.30	16.90%	41.5
3-Jan	5am – 9am	0.216	0.182	0.035	309.82	16.10%	46.99
4-Jan	5am – 9am	0.212	0.172	0.039	350.01	18.60%	48.74
7-Jan	5am – 9am	0.148	0.113	0.034	305.51	23.20%	51.19
15-Jan	5am – 9am	0.159	0.123	0.036	327.48	22.90%	60.15
16-Jan	5am – 9am	0.138	0.103	0.035	316.07	25.30%	61.88
17-Jan	5am – 9am	0.106	0.074	0.031	285.54	29.70%	60.42
22-Jan	5am – 9am	0.181	0.163	0.018	300.60	10.00%	51.53
23-Jan	5am – 9am	0.185	0.158	0.027	519.76	14.60%	49.24
24-Jan	5am – 9am	0.161	0.136	0.025	574.10	15.50%	56.99
4-Feb	5am – 9am	0.134	0.103	0.031	857.22	23.00%	53.78
5-Feb	5am – 9am	0.160	0.127	0.033	930.41	20.60%	49.75
6-Feb	5am – 9am	0.224	0.195	0.029	833.68	13.00%	45.5
7-Feb	5am – 9am	0.225	0.198	0.028	801.34	12.20%	47.26
8-Feb	5am – 9am	0.214	0.185	0.029	866.25	13.70%	47.03
11-Feb	5am – 9am	0.219	0.192	0.027	737.52	12.10%	44.29
11-Feb	6pm – 10pm	0.151	0.115	0.035	85.79	23.40%	50
12-Feb	5am – 9am	0.199	0.174	0.024	531.40	12.30%	47.26
12-Feb	6pm – 10pm	0.127	0.109	0.018	164.46	14.10%	57.2
13-Feb	5am – 9am	0.135	0.109	0.025	556.92	18.70%	56.98
13-Feb	6pm – 10pm	0.155	0.132	0.024	217.77	15.30%	52.61
14-Feb	5am – 9am	0.105	0.083	0.022	479.61	20.80%	58.48
14-Feb	6pm – 10pm	0.130	0.109	0.021	197.17	16.50%	55.72
15-Feb	5am – 9am	0.140	0.113	0.027	615.23	19.30%	52.25
15-Feb	6pm – 10pm	0.137	0.115	0.022	201.96	16.00%	55.27
19-Feb	5am – 9am	0.224	0.197	0.026	814.79	12.20%	46.54
20-Feb	5am – 9am	0.214	0.184	0.030	932.78	14.30%	47.98
21-Feb	5am – 9am	0.191	0.160	0.031	980.98	16.50%	46.04
22-Feb	5am – 9am	0.226	0.194	0.032	1,059.59	14.10%	45.55
All Events							
Avg.	**AM**	**0.186**	**0.157**	**0.028**	**959.92**	**15.10%**	**49.72**
Avg.	**PM**	**0.138**	**0.117**	**0.021**	**196.79**	**15.50%**	**54.68**

Table B-2: Event Savings for All Events and Average Events (thm)

Date	Event Window	Average Total Event Load w/o DR (thm)	Average Total Event Load w DR (thm)	Average Event Savings (thm)	Aggregate Event Savings (thm)	Event Savings (%)	Avg. Event Temp. (F)
2-Jan	5am – 9am	0.887	0.738	0.150	1,333.19	16.90%	41.5
3-Jan	5am – 9am	0.866	0.727	0.139	1,239.30	16.10%	46.99
4-Jan	5am – 9am	0.846	0.689	0.157	1,400.02	18.60%	48.74
7-Jan	5am – 9am	0.590	0.453	0.137	1,222.06	23.20%	51.19
15-Jan	5am – 9am	0.637	0.491	0.146	1,309.93	22.90%	60.15
16-Jan	5am – 9am	0.552	0.413	0.140	1,264.28	25.30%	61.88
17-Jan	5am – 9am	0.423	0.297	0.126	1,142.18	29.70%	60.42
22-Jan	5am – 9am	0.724	0.652	0.072	1,202.39	10.00%	51.53
23-Jan	5am – 9am	0.740	0.632	0.108	2,079.05	14.60%	49.24
24-Jan	5am – 9am	0.645	0.545	0.100	2,296.39	15.50%	56.99
4-Feb	5am – 9am	0.534	0.411	0.123	3,428.89	23.00%	53.78
5-Feb	5am – 9am	0.640	0.508	0.132	3,721.64	20.60%	49.75
6-Feb	5am – 9am	0.896	0.779	0.116	3,334.72	13.00%	45.5
7-Feb	5am – 9am	0.901	0.791	0.110	3,205.34	12.20%	47.26
8-Feb	5am – 9am	0.858	0.740	0.118	3,464.98	13.70%	47.03
11-Feb	5am – 9am	0.874	0.768	0.106	2,950.08	12.10%	44.29
11-Feb	6pm – 10pm	0.603	0.461	0.141	343.17	23.40%	50
12-Feb	5am – 9am	0.794	0.697	0.098	2,125.60	12.30%	47.26
12-Feb	6pm – 10pm	0.509	0.438	0.072	657.83	14.10%	57.2
13-Feb	5am – 9am	0.539	0.438	0.101	2,227.69	18.70%	56.98
13-Feb	6pm – 10pm	0.621	0.527	0.095	871.10	15.30%	52.61
14-Feb	5am – 9am	0.418	0.331	0.087	1,918.44	20.80%	58.48
14-Feb	6pm – 10pm	0.522	0.436	0.086	788.69	16.50%	55.72
15-Feb	5am – 9am	0.562	0.453	0.109	2,460.92	19.30%	52.25
15-Feb	6pm – 10pm	0.548	0.460	0.088	807.83	16.00%	55.27
19-Feb	5am – 9am	0.894	0.789	0.105	3,259.16	12.20%	46.54
20-Feb	5am – 9am	0.858	0.738	0.120	3,731.11	14.30%	47.98
21-Feb	5am – 9am	0.765	0.641	0.124	3,923.93	16.50%	46.04
22-Feb	5am – 9am	0.904	0.777	0.127	4,238.37	14.10%	45.55
All Events							
Avg.	**AM**	**0.743**	**0.630**	**0.113**	**3,839.69**	**15.10%**	**49.72**
Avg.	**PM**	**0.553**	**0.467**	**0.085**	**787.18**	**15.50%**	**54.68**

Table B-3: Daily Savings for All Events and Average Events (thm)

Date	Event Window	Average Total Daily Load w/o DR (thm)	Average Total Daily Load w DR (thm)	Average Daily Savings (thm)	Aggregate Daily Savings (thm)	Daily Savings (%)	Avg. Event Temp. (F)
2-Jan	5am – 9am	3.343	3.340	0.003	30.55	0.10%	41.5
3-Jan	5am – 9am	3.033	3.014	0.018	164.79	0.60%	46.99
4-Jan	5am – 9am	2.890	2.857	0.033	291.34	1.10%	48.74
7-Jan	5am – 9am	2.366	2.286	0.080	714.39	3.40%	51.19
15-Jan	5am – 9am	2.883	2.809	0.074	662.76	2.60%	60.15
16-Jan	5am – 9am	2.232	2.127	0.105	952.60	4.70%	61.88
17-Jan	5am – 9am	1.866	1.716	0.150	1,360.44	8.00%	60.42
22-Jan	5am – 9am	2.464	2.413	0.051	848.75	2.10%	51.53
23-Jan	5am – 9am	2.305	2.230	0.075	1,446.10	3.30%	49.24
24-Jan	5am – 9am	1.844	1.772	0.071	1,641.09	3.90%	56.99
4-Feb	5am – 9am	2.416	2.290	0.126	3,506.92	5.20%	53.78
5-Feb	5am – 9am	2.903	2.783	0.120	3,391.69	4.10%	49.75
6-Feb	5am – 9am	3.385	3.329	0.056	1,614.91	1.70%	45.5
7-Feb	5am – 9am	3.125	3.077	0.048	1,398.50	1.50%	47.26
8-Feb	5am – 9am	2.875	2.813	0.062	1,811.12	2.10%	47.03
11-Feb	5am – 9am	3.051	2.985	0.066	1,820.15	2.10%	44.29
11-Feb	6pm – 10pm	3.421	3.369	0.053	127.68	1.50%	50
12-Feb	5am – 9am	2.617	2.581	0.036	775.58	1.40%	47.26
12-Feb	6pm – 10pm	3.050	3.003	0.046	426.49	1.50%	57.2
13-Feb	5am – 9am	2.489	2.397	0.092	2,024.98	3.70%	56.98
13-Feb	6pm – 10pm	2.793	2.784	0.009	80.43	0.30%	52.61
14-Feb	5am – 9am	2.025	1.953	0.073	1,601.90	3.60%	58.48
14-Feb	6pm – 10pm	2.273	2.211	0.063	574.29	2.80%	55.72
15-Feb	5am – 9am	2.316	2.234	0.082	1,859.98	3.50%	52.25
15-Feb	6pm – 10pm	2.663	2.644	0.019	175.23	0.70%	55.27
19-Feb	5am – 9am	3.169	3.126	0.043	1,353.27	1.50%	46.54
20-Feb	5am – 9am	3.423	3.351	0.072	2,235.26	2.10%	47.98
21-Feb	5am – 9am	3.354	3.263	0.091	2,879.44	2.80%	46.04
22-Feb	5am – 9am	3.168	3.117	0.050	1,671.77	1.60%	45.55
All Events							
Avg.	**5am – 9am**	**2.802**	**2.740**	**0.063**	**2,132.74**	**2.20%**	**49.72**
Avg.	**6pm – 10pm**	**2.731**	**2.696**	**0.035**	**318.69**	**1.30%**	**54.68**

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Gas Demand Response Pilot Implementation Plan, 2018-2021

Consolidated Edison Company of New York, Inc.
Updated: July 1, 2020
Case 17-G-0606

Contents

1 Executive Summary

Consolidated Edison Company of New York, Inc. ("Con Edison" or "the Company") proposed the Smart Solutions for Natural Gas Customers Program ("Smart Solutions")[1] to address increased demand for natural gas in its service territory and limited pipeline capacity. This innovative, integrated, multi-solution proposal seeks to decrease gas usage and procure alternative resources to meet customer heating and other thermal needs. As part of the Smart Solutions portfolio and pursuant to the New York Public Service Commission's ("PSC") Order,[2] Con Edison established a Gas Demand Response ("DR") Pilot ("Gas DR Pilot" or "Pilot") that aims to reduce net customer gas demand during the entirety of a peak gas demand day during the coldest winter days.

Gas DR has been piloted between November 1, 2018 through March 31, 2019 (the "2018/2019 Winter Capability Period"), November 1, 2019 through March 31, 2020 (the "2019/2020 Winter Capability Period') and will continue for the period between November 1, 2020 through March 31, 2021 (the "2020/2021 Winter Capability Period") in certain zones in Con Edison's service territory, with a prescribed limit for the number of customers who are eligible to participate. The designation of this effort as a Pilot and the limit on the number of participating customers are necessary due to the limited experience with gas DR in Con Edison's service territory as well as in New York State and nationally. Con Edison intends to use this Pilot to gather insights into optimal gas DR operational parameters and achievable customer response that will potentially inform a tariffed program to be proposed at the end of the Pilot, if appropriate.

This Implementation Plan outlines the key parameters of the Gas DR Pilot, which consists of a Performance-Based Gas DR Offering primarily targeting Con Edison's commercial and industrial ("C&I") gas customers and multi-family buildings with centralized heating systems and a Direct Load Control ("DLC") Gas DR Offering targeting Con Edison's residential gas customers.

The Company developed the Gas DR Pilot parameters by leveraging interviews and discussions with Con Edison's largest gas customers, as well as aggregators and solution providers that are active in the electric DR space in New York State. The Pilot has been designed to account for customer capabilities, while providing sufficient economic incentive to customers for participation. Where possible, Con Edison has leveraged many of the existing capabilities and procedures from its electric DR programs in the design of the Gas DR Pilot, with the ultimate goal of making Gas DR Pilot participation attractive for existing electric DR participants (who are often also gas customers) and aggregators.

The Company has received authorization for $5.1 million to support the Gas DR Pilot over a three-year period. The Company intends to continue reallocating financial resources within the various components of the Gas DR Pilot as needed as authorized by the PSC. If incentive costs are higher than anticipated, the Company will petition the Commission for additional funding.

Following the submission of this updated Implementation Plan, Con Edison will continue preparing the administrative functions that will enable the continuation of the program in time for the 2020/2021

[1] Case No. 17-G-0606, *Petition of Consolidated Company of New York, Inc. for Approval of the Smart Solutions for Natural Gas Customers Program* (filed September 29, 2017).
[2] Case No. 17-G-0606, New York State Public Service Commission, *Order Approving With Modification Gas Demand Response Pilot* (effective August 9, 2018).

Winter Capability Period. During the period of the Pilot, Con Edison will continue engaging customers and the market and will provide regular updates to New York State Department of Public Service Staff ("Staff") and respond to any Staff concerns and recommendations.

2 Introduction

2.1 Background to the Gas DR Pilot

Con Edison delivers natural gas to approximately 1.1 million customers in Manhattan, the Bronx, the First and Third Wards of Queens, and most of Westchester County. Natural gas is delivered by interstate pipelines to Con Edison at various points in or near its service territory and is distributed to customers through approximately 4,300 miles of mains and 370,000 service lines. Con Edison must have sufficient pipeline capacity available to meet its customers' demand on a peak design day. The design day customer demand only reflects gas used by firm gas customers and does not include, for example, the gas supply needs of customers taking interruptible delivery service or electric generating stations; to the extent interruptible customers require fuel on the coldest days of the year, they are required to use an alternate fuel.

On the supply side, pipeline capacity coming into Con Edison's service territory is fully contracted, and proposals for new pipeline projects have recently encountered increased difficulty in securing necessary preconstruction permits.

To address the increased customer demand and limited pipeline capacity, Con Edison has proposed the Smart Solutions for Natural Gas Customers Program.[3] This innovative, integrated, multi-solution strategy seeks to decrease gas usage and procure alternative resources to meet customer heating and other thermal needs. The Smart Solutions Program is designed to develop alternative means to meet customers' heating and other thermal needs in a cost-effective manner, seek to defer the Company's requirement for incremental upstream pipeline capacity, reduce the use of pipeline delivered services, mitigate the need for a moratorium on new gas customer interconnections, and contribute to the achievement of state and local environmental goals.

The Smart Solutions proposal includes four non-traditional solutions to address customer gas needs:

- Developing the Gas DR Pilot to reduce net customer demand during the entirety of a peak gas demand day;
- Doubling the Company's existing gas energy efficiency program;
- Creating a gas innovation program for renewable alternatives to natural gas heating (request for information issued in Q2 2018); and
- Issuing a market solicitation for additional Non-Pipeline Solutions (NPS) on either the supply or demand side, which will provide a pathway for the advancement of new technologies and facilitate new abilities to engage with and deliver service to customers; examples include beneficial electrification of heating and localized natural gas storage alternatives (a request for proposals was issued on December 15, 2017).

Con Edison launched a Gas DR Pilot for the 2018/2019 Winter Capability Period consisting of (1) a Performance-Based Gas DR Pilot targeting Con Edison's C&I customers and multi-family buildings with centralized heating systems and (2) a DLC Gas DR Pilot targeting Con Edison's residential customers.

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[3] For additional information, see Case No. 17-G-0606, *Petition of Consolidated Company of New York, Inc. for Approval of the Smart Solutions for Natural Gas Customers Program* (filed September 29, 2017).

This Implementation Plan describes the characteristics of the Gas DR Pilot, as informed by Con Edison's operational requirements, and the capabilities of Con Edison's customers and the market using smart thermostat technology.

2.2 Gas DR Pilot Objectives

The Gas DR Pilot tests the feasibility of incentivizing customers to provide net reductions of natural gas demand during peak gas demand days (from 10:00 am to 10:00 am the following day) on the coldest days of the winter.

The overall goals of the Gas DR Pilot are to:

- Understand the magnitude of net load reduction that customers are able to provide following notification over a 24-hour window from 10:00 am to 10:00 am the following day (an "event");
- Test customer engagement as measured by number of customers enrolled and participant response;
- Assess third-party participation as measured by number of aggregators enrolled and aggregator response;
- Streamline event dispatch based on internal and external stakeholder response;
- Test the participants' ability and willingness to participate in consecutive events (i.e., when events occur consecutively over multiple days) and events on holidays;
- Collect information on successful customer gas use reduction strategies;
- Inform the process of setting program incentive levels;
- Test baseline methodologies for robustness; and
- Provide data on reliability and repeatability of total reductions during events, as an input to Con Edison's peak day gas demand forecasting process.

The Gas DR Pilot was offered initially in the 2018/2019 Winter Capability Season, continued to be offered in the 2019/2020 Winter Capability Season and will continue being offered in the 2020/2021 Winter Capability Season. Con Edison has evaluated the results of the 2018/2019 and 2019/2020 Winter Capability Seasons and will continue to evaluate the results of the Gas DR Pilot after each Winter Capability period to determine if it should be established as a full program, as well as the optimal program parameters.

2.3 Stakeholder Engagement

To support the development of the Gas DR Pilot and this Implementation Plan, Con Edison actively engaged external stakeholders to collect input that informed Pilot design. Specifically, Con Edison:

- **Conducted interviews** in early 2018 with seven natural gas customers spanning a range of building types, technology types, and customer segments to discuss the Gas DR Pilot concept, the customers' technical capabilities, program design attributes, potential barriers to participation, and key insights into how Con Edison could design the Gas DR Pilot;

- **Conducted interviews** with interested third parties including aggregators as well as building management system ("BMS") and energy management system ("EMS") providers to understand their capabilities to contribute to the Gas DR Pilot;
- **Presented in the Demand Response Forum** on February 27, 2018 the initial outline of the Gas DR Pilot to a broad group of stakeholders currently active in Con Edison's electric DR programs;
- **Collected feedback in a Gas DR Pilot Design Workshop** on April 2, 2018 from customers, aggregators, and other local stakeholders on the preliminary design elements of the Gas DR Pilot, with an open comment period following the workshop for stakeholders to provide additional input; and
- **Tested DLC capability** with a limited effort to test the ability and willingness of customers who have already installed a specific brand of smart thermostat to participate in a DLC-type Gas DR Pilot.
- **Conducted a Gas Demand Response Forum** on June 26, 2019 and on June 18, 2020. The 2018/2019 and 2019/2020 Winter Capability results and proposed changes to the Pilot were reviewed in an open meeting with stakeholders.

Con Edison will continue to engage with stakeholders throughout the duration of the Gas DR Pilot to collect further feedback as both customers and aggregators learn and gain experience from their participation in the Gas DR Pilot.

3 Summary of Changes since the 2019/2020 Winter Capability Period

Outlined below are changes to this Implementation Plan since it was last filed prior to the 2019/2020 Winter Capability Period. Each of the changes below are further elaborated upon in the appropriate sections of this document.

1. Updated the incentive levels for the Performance Based Reservation Payment option and revised the zones to reflect updated value of load relief by geographic area.
   - Incentive levels have been updated to reflect stakeholder feedback, updated relative value of load relief and to align with the Company's recent NPS Request for Information solicitation.[4]
2. Revised the enrollment deadlines for customers participating by meter Option 4, Advanced Metering Infrastructure (AMI) Interface Management Unit (IMU) installation, to allow for increased time for AMI IMU installation and sufficient data for Customer Baseline Load ("CBL") calculation.
   - September 1 enrollment deadline for November 1 start date.
   - October 1 enrollment deadline for December 1 start date.
   - Enrollment deadlines for all remaining metering options are unchanged.
3. Removed the target enrollment of 1,000 participating customers for the DLC Pilot.

[4] https://www.coned.com/-/media/files/coned/documents/business-partners/business-opportunities/non-pipes/non-pipeline-solutions-to-provide-peak-period-natural-gas-system-relief-rfi.pdf?la=en

4 Performance-Based Gas DR Offering Description

4.1 Eligibility

For the Performance-Based Gas DR Offering, Con Edison will enroll customers that express interest in the Performance-Based Gas DR Pilot and meet the following eligibility criteria:

- **Firm service:** Customers must take firm gas delivery service. If a customer has either switched to firm gas delivery service from interruptible delivery service or has moved to firm delivery service as a result of failure to meet interruptible delivery service requirements, the customer must take firm delivery service for a full calendar year before being eligible to enroll in the Performance-Based Gas DR Offering.
- **Minimum enrollment value:** Both aggregators and direct participants will be required to provide a minimum enrollment value of five dekatherms of Net Load Relief per gas day. Customers may enroll through a qualified aggregator or as a direct participant, provided that customers enrolled as a direct participant provide the minimum enrollment value. In addition, all participating customers with a volume corrector or a BMS systems connected to a volume corrector must enroll for a minimum of one dekatherm.
- **Customer segments:** While all customer segments will be eligible to participate, the primary focus is on C&I gas customers and multi-family buildings with centralized gas heating systems. Dual enrollment in the Performance-Based Gas DR Offering and the DLC Gas DR Offering will not be allowed.
- **Building end uses:** The Performance-Based Gas DR Offering will primarily target natural gas consumption from space heating, water heating, combined heat and power systems, and process loads.
- **Reduction strategies:** Customers will have the option to participate through either curtailing gas consumption or reducing gas usage by fuel-switching to electric during the event days. Fuel-switching to liquid fuels is not permitted.
- **Metering requirements:** Customers will be required to have at least one of the four metering options outlined in Section 4.3.1 for the collection of interval data.
- **Locations:** The Performance-Based Gas DR Offering will be offered to customers in portions of the Con Edison gas service territory where reducing peak day gas usage would mitigate pipeline needs and/or reduce the Company's use of pipeline delivered services. The Performance-Based Gas DR Offering incentives are based on two value zones that are identified by zip code: Zone A (higher tier) and Zone B (lower tier). Section 4.3.4 provides details on customer incentives by zone and Appendix A includes a table of the zip codes within each zone, as well as the zip codes that are ineligible to participate in the Performance-Based Gas DR Offering.
- **Enrollment limit:** Enrollment in the Performance-Based Gas DR Offering was limited to 500 customers in the 2018/19 Winter Capability Period and 750 customers in the 2019/2020 Winter Capability Period. Enrollment during the 2020/2021 Winter Capability Period is limited to 1,000 customers.

4.2 Operational Parameters

Table 1 summarizes the key parameters for the Performance-Based Gas DR Offering, based on the operational requirements presented in Section 4.1, as well as customer and market capabilities.

Table 1. Summary of Performance-Based Gas DR Pilot Parameters

Parameter	Definition
Event Trigger	• The event trigger will be based on a forecasted average daily temperature at the Central Park weather station as forecasted by Con Edison 24 hours in advance of the event day (which, as noted below, begins at 10:00am). • For the 2020/2021 Winter Capability Period, the trigger will be 18°F. The event trigger may be reassessed prior to each season. • Con Edison will have the right to call events based on the forecasted Event Trigger but is not obligated to call an event.
Frequency of Events	• Based on previous 10 years of weather data, Con Edison projects an average of 3-4 events per season for the 2020/2021 Winter Capability Period event trigger of 18°F. • Con Edison may call one or more Test Events per season, depending on the frequency of Planned Events.
Capability Period	• November 1 through March 31.
Contracted Hours	• 24-hour period (10:00 am to 10:00 am the following day), 7 days a week (weekdays, weekends, and holidays), during the Capability Period.*
Notification Time	• An advisory notification will be provided to participants at least 21 hours in advance of the event. An activation/cancellation notification will be sent at least two hours in advance of the event.
Net Load Relief	• The key benefit to Con Edison's gas system is the load relief achieved during a 24-hour event period, compared to the customer's forecasted usage ("Net Load Relief").
Event Participation	• Customers and/or aggregators are responsible for their participation strategy on gas DR event days. • Con Edison will not have direct control of customer appliances, controls, or other equipment. **
Prohibited Reduction Modes	• Demand reduction via switching to fuel oil or other liquid fuels that result in an increase in customer emissions during a gas DR event is not allowed.***

* 10 out of the 20 top send-out days over the last 4 years occurred during holiday and/or weekend days. Events occurring on Thanksgiving Day, Christmas Day, and/or New Year's Day holidays will receive higher incentive payments (see Section 4.3.4).

** Customers who own or manage multi-family residential buildings in New York City and Westchester County must meet all applicable code requirements for space heating and water heating temperature settings for tenant spaces, regardless of their participation in a gas DR event.[5]

[5] Current New York City code requires 68°F from 6:00 am to 10:00 pm, and 62°F 10:00 pm to 6:00 am, and 120°F water at the tap. NYC Housing Prevention and Development. "Heat and Hot Water." Accessed May 2020. Available at: https://www1.nyc.gov/site/hpd/services-and-information/heat-and-hot-water-information.page. Current Westchester county code requires the inside temperature should be 68 degrees between 6 a.m. and 10 p.m between Oct 1 and May 31 when the outdoor temperature is below 55 degrees Fahrenheit. Available at: https://homes.westchestergov.com/tenants/code-enforcement. Individual municipalities in Westchester county have additional heating and hot water requirements that must also be adhered to.

*** Participation in the Performance-Based Gas DR Pilot does not limit or modify customer requirements to abide by all environmental laws or regulations limiting emissions of various pollutants, including during participation in a DR event. Con Edison reserves the right to confirm after a DR event that a participating customer did not engage in a Prohibited Reduction Mode. Starting with the 2019/2020 Winter Capability Period, Con Edison reserves the right to impose and enforce a one-year ban on participation in the Gas DR Pilot for any customer that is found to have utilized fuel switching to fuel oil or liquid fuels as a reduction strategy. Participants that are identified to have potentially switched to fuel oil or liquid fuels will have their performance put under administrative review, per the Pilot's guidelines. Participants that are confirmed to have switched to fuel oil or liquid fuels will be disqualified from receiving any incentive payments for the entirety of the Winter Capability Period that the violation occurred in and will be ineligible to participate during the following Winter Capability Period.

4.3 Delivery Parameters and Procedures

4.3.1 Customer Enrollment and Metering Enablement

Customers enrolled by October 1 will be able to participate in the Performance-Based Gas DR Offering beginning November 1. Customers who miss the October 1 enrollment deadline can enroll by November 1 for participation in the Pilot beginning December 1. Customers requesting to have their gas meter upgraded with an AMI IMU in order to participate in the Performance-Based Gas DR Offering must enroll by September 1 to begin participation on November 1. Customers requesting to have their gas meter upgraded with an AMI IMU who miss the September 1 enrollment deadline can enroll by October 1 for participation in the Pilot beginning December 1.

Con Edison must be able to collect and record hourly gas usage interval data on a daily basis for all Performance-Based Gas DR Offering participants. Because the rollout of gas AMI meters will be limited during the initial years of the Performance-Based Gas DR Offering, Con Edison will utilize one of four different metering options for the collection of interval data:

> **Option 1**: Con Edison will use AMI meters for data collection where the customer has already had an AMI gas meter installed and the AMI communications network is actively collecting data from the customer's AMI gas meter.
>
> **Option 2**: Con Edison will allow customers using a customer-owned interval data recording device, such as a BMS, EMS or other recording device capable of collecting hourly interval data from their existing Con Edison gas meter to use such systems for data collection and submit the data directly to Con Edison in a pre-established format.
>
> **Option 3**: Con Edison will retrieve data from customers without AMI meters or customer-owned interval data recording devices, but whose meters have volume correctors that record and store data, via a physical meter read either on a monthly basis or at the end of the winter season (depending on the volume corrector data capacity).
>
> **Option 4**: Customers without AMI meters, customer-owned interval data recording devices, or volume correctors can request to have their gas meters upgraded with an AMI IMU that will be installed by Con Edison and agree to enroll in the Performance-Based Gas DR Offering. Con Edison will collect the data via a physical meter read on a monthly basis.

Hourly interval data collected or provided to the Company under Options 2, 3, and 4 above will not be used for normal bill calculations, but will only be utilized by the Company for the purposes of establishing a participating customer's DR baseline and the customer's performance during a Planned Event or Test Event.

The process for establishing metering capabilities and collecting the interval data for participating customers is as followed:

- Customer requests to participate in the Performance-Based Gas DR Offering,
- Con Edison confirms existing meter configuration and determines which of the four metering options the customer can use to participate in the Performance-Based Gas DR Offering,
- For Option 3, Con Edison arranges data collection from the customer meter, and

- For Option 4, Con Edison arranges for installation of IMU retrofit unit at Con Edison's own cost and arranges for data collection from the customer meter.

Customer data collected using customer-owned interval data recording devices (Option 2) will be subject to measurement and verification spot checks by Con Edison. If feasible, for customers with an existing customer-owned interval data recording device, Con Edison will attempt to install an IMU, thereby allowing them to participate in the Performance-Based Gas DR Offering under Option 4.

A maximum of 150 customers can enroll in Option 3 and a maximum of 150 customers can enroll in Option 4 every year. In order to be eligible for the meter retrofit and additional meter reading associated with either Options 3 or 4, participants must have monthly usage of at least 400 dekatherms in at least one month during the winter 2019/2020 heating season.

If a customer enrolled in Option 4 does not provide Con Edison with access to the customer's site during the visit for the installation of the IMU retrofit unit, the customer will be ineligible to participate in the Pilot for the remainder of the season. If a customer enrolled in any of the four options does not provide Con Edison with access to the customer's site for collection of data during the season at Con Edison's request, the customer will receive a zero Performance Factor (as defined in Section 4.3.4) for each month that access is not available.

4.3.2 Event Notification

As outlined in the Performance-Based Gas DR Offering operational parameters (see Section 4.2), Con Edison will have the option, but not the obligation, of calling an event when the forecasted average daily temperature is 18°F or below based on the average hourly temperature at the Central Park weather station as forecasted by Con Edison 24 hours in advance of the event day.

Notifications for Performance-Based Gas DR Offering events will be sent via phone or email to aggregators and direct participants. Advisory notifications will be issued 21 or more hours in advance of the event. Activation/cancellation notifications will be issued two or more hours in advance of the event.

Con Edison will also have the option, but not the obligation, of calling one or more Test Events, in which it requests that direct participants and aggregators provide Net Load Relief over a 24-hour period in order to test participants' response to a request for load relief. Test Event notifications will be issued 21 or more hours in advance of the event. Advisory/cancellation notifications will be issued two or more hours in advance of the event. Performance payments for Test Events will be made for the Net Load Relief achieved up to the customer's enrollment value.

4.3.3 Measurement and Verification

To measure the customers' baseline usage for determining gas savings on an event day, Con Edison will apply an adapted version of the CBL procedure that is currently used for Con Edison's electric DR programs. Similar to electric DR, determining the proper baseline will be critical to calculating the value provided by the Performance-Based Gas DR Offering, as gas DR event days will be associated with the coldest periods with highest gas use, and would normally see an increase in gas consumption.

Key features of the Performance-Based Gas DR Offering CBL include the following:

- CBL Basis and CBL Window[6] defined as:
    - Weekday events: Highest 5 of 10 previous weekdays.
    - Saturday events: Highest 2 of 3 previous Saturdays.
    - Sunday events: Highest 2 of 3 previous Sundays.
    - Holiday events: Highest 2 of 3 previous Sundays.
- CBL Window excludes the following:
    - Day before the event,
    - Other event days (for weekday events),
    - Holidays (for weekday events), and
    - Low usage days with average daily event period usage less than 25 percent of the average event period usage level.
- Average Day CBL is the average of the total daily usage for the days that comprise the CBL Basis (e.g., the CBL for a weekday event will be a single daily value representing the average of the daily usage for the highest 5 of 10 previous weekdays).[7]
- A Weather-Sensitive adjustment option will be available, in which the Average Day CBL is adjusted to account for the difference in temperature between the event day and the CBL Basis.
- For consecutive weekday events, the CBL Basis for the first event day will be used for each of the consecutive weekday events.
- At the initial enrollment in the Performance-Based Gas DR Offering, participants may elect either the Average Day CBL or the Weather-Sensitive adjustment CBL formula.
- The Company reserves the right to require participants who elect the Weather-Sensitive adjustment to demonstrate weather-sensitive load upon making the CBL selection or at any point during the Capability Period.

The development of a baseline methodology for a 24-hour DR event period is a novel practice in the industry and is based on limited data for historical customer hourly and daily gas usage. Con Edison intends to test the CBL methodology through the Gas DR Pilot implementation and will re-analyze and potentially revise the CBL methodology during or immediately after the Gas DR Pilot is complete based on the results of the Gas DR Pilot. If, during the course of the Pilot, Con Edison determines that revisions to the CBL are necessary, it will convene a stakeholder session to discuss modifications.

The full procedure for the determination of the customer baseline will be posted on Con Edison's website in a separate document for participant reference.

[6] The CBL Window is the set of days that will serve as representative of participant's typical usage. The CBL Basis is the set of days within the CBL Window to be used to develop CBL values for the event.

[7] The Performance-Based Gas DR Offering CBL will be based on the net usage over the event day, as opposed to the methodology used for the electric DR CBL, which is based on the average of the hourly usage in each hour of the event window.

4.3.4 Incentives and Settlement

Customers will be eligible for a reservation payment and performance payment based on their participation in DR events for the Performance-Based Gas DR Offering throughout the five-month Capability Period (November 1 through March 31). Incentive payments will be made at the end of the season based on net 24-hour therm reductions below that customer's CBL during event days (therm-day).

Table 2
3 highlights the proposed incentive levels for participating customers in each value zone.[8]

Payment Structure	Zone A (Rye/White Plains, North Bronx, North Manhattan)	Zone B (Southern Bronx, Queens, Southern Manhattan)
Monthly Reservation Payment ($/Therm-day of Net Load Relief per DR month)	$9	$5
Performance Payment during DR event ($/Therm-day of Net Load Relief per DR event)	$1	$1
Holiday / 3 Consecutive Event Days / Voluntary Performance Payment ($/Therm-day of Net Load Relief per DR event)	$2	$2
Estimated Total Payment ($/Therm-day per DR season) for Net Load Relief during a 'typical winter season' based on historical weather data	$50	$30

- **Reservation Payment ($/therm-day per month):** A monthly incentive for customers based on their commitment during the capability period to provide Net Load Relief ("enrollment value"). Reservation incentives are based on each customer's enrollment value, after adjusting for the Monthly Performance Factor (discussed below), for each month of the Capability Period the customer is enrolled. The Reservation Payment per month is equal to the applicable Reservation Payment Rate per therm per month multiplied by the participating customer's therm of contracted Load Relief multiplied by the Performance Factor for the month.
- **Performance Payment ($/therm-day per event):** A daily incentive for customers based on their Net Load Relief during each event. Performance incentives are determined by measured net 24-hour therm reduction below that customer's CBL during each event day.
- **Higher Performance Payment ($/therm-day per event):** An additional daily incentive for customers based on their Net Load Relief during events that occur on three specified holidays (Thanksgiving Day, Christmas Day, and/or New Year's Day) or events over three or more consecutive event days (with the higher performance payment starting on the third consecutive event day).

[8] Appendix A provides details on the value zones, including ineligible service areas.

- **Voluntary Performance Payment ($/therm-day per event):** A daily incentive for customers to provide Net Load Relief during certain events that are not subject to the Reservation Payment:
  - Events called with shorter notice than the 21-hour standard event notice,
  - Events called at temperatures higher than 18°F trigger, or
  - Responses to event notifications by customers who enroll after the enrollment deadline and are therefore not eligible for reservation payments.
- **Event Performance Factor**: The Event Performance Factor is the ratio of (i) the dekatherms of Net Load Relief provided during a Planned Event or Test Event up to the dekatherms of contracted Net Load Relief to (ii) the dekatherms of contracted Net Load Relief.
- **Monthly Performance Factor**: A Monthly Performance Factor will be applied to the reservation payment for each month of the season and will be based on the average Event Performance Factor from all Planned Events or Test Events called during the month. The Monthly Performance Factor for the month is used to calculate the Reservation Payment for that month and each month thereafter until the month in which the next Test Event or Load Relief Period is called by the Company for that account during the current Capability Period. The Monthly Performance Factor determined for the first month in which a Load Relief Period or Test Event is called for an account during a Capability Period will be applied retroactively starting with the first month the customer was enrolled during the Capability Period.

Table 2. 2018-2019 and 2019-2020 Performance-Based Gas DR Offering Incentive Levels

Payment Structure	Zone A (Rye/White Plains, North Bronx, North Manhattan)	Zone B (Southern Bronx, Queens, Southern Manhattan)
Monthly Reservation Payment ($/Therm-day of Net Load Relief per DR month)	$9	$5
Performance Payment during DR event ($/Therm-day of Net Load Relief per DR event)	$1	$1
Holiday / 3 Consecutive Event Days / Voluntary Performance Payment ($/Therm-day of Net Load Relief per DR event)	$2	$2
Estimated Total Payment ($/Therm-day per DR season) for Net Load Relief during a 'typical winter season' based on historical weather data	$50	$30

Table 3. 2020-2021 Performance-Based Gas DR Offering Incentive Levels

Payment Structure	Zone 1 (Westchester	Zone 2 (New York City portion of Con	Zone 3 (Westchester north of moratorium area within

	Moratorium Area)	Edison's gas service territory)	Con Edison's Gas Service Territory)
Monthly Reservation Payment ($/Therm-day of Net Load Relief per DR month)	$12	$7	$5
Performance Payment during DR event ($/Therm-day of Net Load Relief per DR event)	$1	$1	$1
Holiday / 3 Consecutive Event Days / Voluntary Performance Payment ($/Therm-day of Net Load Relief per DR event)	$2	$2	$2
Estimated Total Payment ($/Therm-day per DR season) for Net Load Relief during a 'typical winter season' based on historical weather data	$65	$40	$30

Section 4.1 and Appendix A provide details on eligible zones.

Con Edison designed the Performance-Based Gas DR Offering's incentives to offer meaningful compensation to participating customers, while achieving a Benefit Cost Analysis ("BCA") value of greater than 1.0 (see Section 6.2).

The proposed incentive levels were developed using a number of reference points:

- Program BCA thresholds for the Smart Solutions portfolio,
- Electric DR incentive expectations from the 2015 Willingness-to-Accept study,[9]
- Published incentive levels in the National Grid (KED-NY and KED-LI) gas DR pilot,
- The relative value to a customer of current electric DR program incentives as compared to a customer's annual bill, and
- Other commercial information on the value of gas DR available to Con Edison.

Customers will be paid for the entirety of the Performance-Based Gas DR Offering season in a single payment at the end of the season.

4.3.5 Marketing, Outreach, and Customer Engagement

Given the nascency of gas DR in Con Edison's service territory, customer education will be a critical part of the initial marketing efforts to help customers understand the objectives of the Performance-Based Gas DR Offering and the mechanisms for participating. Overall, the marketing strategy will be similar to that of the electric DR program with additional emphasis on education in the first two years of the

[9] Navigant Consulting, Inc. 2015. "Demand Response Survey Research Study – Commercial Demand Response Willingness-to-Accept and Performance Window Customer Research." Prepared for CECONY. January 30, 2015.

Performance-Based Gas DR Offering. Con Edison expects to cross-market the Performance-Based Gas DR Offering with its electric DR programs, particularly in the initial pilot years, to reach customers who have already expressed interest in electric DR participation.

Marketing will be delivered primarily through aggregators, with limited targeted marketing delivered directly by Con Edison to larger C&I customers. The targeted marketing delivered directly by Con Edison will include informational webinars that will be open to the general public and email campaigns.

To support the marketing and outreach efforts more broadly, Con Edison will prepare marketing collateral that can be used to educate customers on the Performance-Based Gas DR Offering, Pilot Guidelines to help participants better understand the rules and processes, and a web page on Con Edison's website with information on the Performance-Based Gas DR Offering with a link to Con Edison's DR email address for further questions and direct engagement.

4.4 Additional Guidelines and Procedures

In order to facilitate access to resources relating to the Performance-Based Gas DR Offering, Con Edison developed a webpage that will provide additional details on the CBL procedure and the Performance-Based Gas DR Offering rules and guidelines.

5 DLC Gas DR Offering Description

The DLC program is the current residential and small commercial component of Con Edison's electric DR offerings. The DLC program supports electric system reliability primarily by using Wi-Fi enabled thermostats (smart thermostats) to control participants' central air conditioning units and reduce energy demand at times of critical system need. These customers have the ability to remotely control their central air conditioning units online through a personal computer or mobile device at all times, and thus can override events called by Con Edison regardless of the customers' location. The DLC program has been offered in Con Edison's service territory since 2002. In alignment with the principles in the Reforming the Energy Vision proceeding, the Company has offered customers a Bring Your Own Thermostat ("BYOT") option since 2014 that allows customers to enroll a thermostat through certain service providers or thermostat manufacturers.

Con Edison proposes a similar BYOT DR option for natural gas customers to reduce gas usage at peak times during November 1 through March 31. Customers will participate in the DLC Gas DR Offering through the BYOT option by providing their own control device and enrolling in the DLC Gas DR Offering through a service provider (i.e., smart thermostat manufacturers and/or aggregators). Through the DLC Gas DR Offering, Con Edison will target customers who have previously enrolled in the electric DLC program, as well as new customers who have eligible Wi-Fi thermostats. Service providers that currently participate in the electric DLC program will be eligible, and encouraged, to participate in the DLC Gas DR Offering as well.

The current DLC BYOT option allows customers to enroll a thermostat through service providers and to receive a one-time sign-up bonus. Customers who currently participate in the DLC program during the summer months and have a gas heating system will receive an additional incentive to enroll in the DLC Gas DR Offering. New customers who have a gas heating system but have not previously registered for the DLC program will receive a sign-up payment at the time of enrollment.

Under the DLC program, there is a sign-up bonus of $85 per thermostat and an additional $25 payment for participation in DR events after Con Edison can verify participation in at least 50 percent of events in the first three summers. The DLC Gas DR Offering may choose to apply a similar incentive structure to the pilot year or opt to test multiple incentive methods to increase pilot participation.

5.1 DLC Gas DR Offering Parameters

The proposed budget (see Table) includes incentive payments for customers and service providers, marketing for DLC Gas DR Offering enrollment, set up fees and administrative costs.

5.1.1 Goals

The DLC Gas DR Offering seeks to test and understand the impact of various parameters to help inform the feasibility and design of an effective program at the end of the pilot period. The pilot intends to test following parameters:

- Duration of events
- Call window (i.e., time of day when events are called)
- Amount of temperature setback

The focus of the testing will be to determine the impact on the following:

- Magnitude of therm savings
- Snapback, i.e., any increase in usage during the gas day but outside of the event period
- Customer overrides and opt-outs

Testing the parameters will be done by splitting participants into groups and applying different parameters to different groups during events, as well as applying different parameters on different event days. The total amount of testing that will be done will depend on the number of participants and the number of events during each season.

In addition, if the initial incentive structure and incentive values (as described below) prove to be insufficient to attract and maintain participants, Con Edison may modify the incentives, which will provide additional information regarding the relationship between incentive levels and customer participation.

5.1.2 Operational Parameters

The operational parameters of the DLC Gas DR Offering, described below in Table 4, generally mirror the Performance-Based Gas DR Offering, with some modifications due to the different nature of the pilots, and the testing described above for the DLC Gas DR Offering.

Table 4 DLC Gas DR Operational Parameters

Parameter	Definition
Event Trigger	• The event trigger will be based on a forecasted average daily temperature at the Central Park weather station as forecasted by Con Edison 24 hours in advance of the event day (beginning at 10:00 a.m.). • For the 2020/2021 Winter Capability Period, the trigger was be 18°F. The event trigger may be reassessed prior to each winter season. • Con Edison will have the right to call events based on the forecasted Event Trigger, but is not obligated to call an event.

Parameter	Definition
Frequency of Events	• Based on previous 10 years of weather data, Con Edison projects an average of 3-4 events per season for the 2020/2021 event trigger of 18°F. • In the 2018/2019 Winter Capability Period, there were 3 events, January 21, January 30, and January 31. • In the 2019/2020 Winter Capability Period, there were no events. • Con Edison may call one or more Test Events per season, based on the frequency of actual events. The duration and event times of a Test Event will be similar to the duration and event times of an actual event. • In the 2018/19 Winter Capability Period, 2 test events were conducted to retrieve operational data on February 27 and March 6, due to technical issues that prevented the successful dispatch of the January 21 and January 31 events. • In the 2019/2020 Winter Capability Period, there were 2 test events, February 14, and February 21.
Capability Period	• November 1 through March 31. • Events may be called on any day of the capability period.
Event Duration	• Con Edison will seek to test the effectiveness of different event durations ranging from 2 – 8 hours. The initial focus will be on 4 and 6 hour durations, with other durations added in if there is the opportunity for additional testing based on the population size and number of events.
Event times	• Con Edison will seek to test the effectiveness of different event times (i.e., start hour of event). All events will take place between 7:00 am and midnight. The first set of start times to be tested will be 10:00 am, 4:00 pm, and 8:00 pm. Additional start times may be tested if there is the opportunity for additional testing based on the population size and number of events.

It should be noted that despite the fact that the triggers for the Performance-Based Gas DR Offering and DLC Gas DR Offering are the same, Con Edison may elect not to call them at the same time based on the frequency of events. Con Edison may also elect to have a different number of Test Events and conduct Test Events at different times for the two pilots since different parameters are being tested by the two pilots (e.g., the DLC Gas DR Offering is testing the snapback effect and customers' propensity to override events).

5.1.3 Incentives

The DLC Gas DR Offering will offer an $85 enrollment incentive per thermostat for customers who have not participated in the electric DLC program. Customers who are enrolled in the electric DLC program will receive an additional $20 enrollment incentive per thermostat for enrolling in the DLC Gas DR Offering. Con Edison may adjust the DLC Gas DR Offering incentive rates as appropriate.

5.1.4 Participating Service Providers

The Company is working with Nest and Resideo (formerly Whisker Labs), which currently supports enrollment of Honeywell thermostats.

6 Gas DR Pilot Budget

6.1 Budget Breakdown

6.1.1 Overview

This section outlines the budget for the delivery and administration of the Gas DR Pilot for three years (November 2018 to March 2021), including both the Performance-Based Gas DR Offering and the DLC Gas DR Offering.

Budget amounts are based on estimates of adoption within Con Edison's customer base. Con Edison will inform Staff of any material revisions to the Gas DR Pilot that are the result of customer participation that is different to what is expected, and to comply with all requirements set forth in any relevant Commission Order(s) issued under Smart Solutions.

Table provides a summary of the estimated budget for the delivery of the Gas DR Pilot for the first three years of operation. Con Edison has estimated the budget on an annual basis; however, the Company will optimize expenditures based on the requirements of the Gas DR Pilot.

Table 5 Gas DR Pilot Budget, 2018-2021

Category	2018-19	2019-20	2020-21	Total
Meter Data Collection	$269,000	$155,000	$155,000	**$579,000**
Customer Incentives	$648,000	$968,000	$1,286,000	**$2,902,000**
Pilot Administration	$490,000	$540,000	$540,000	**$1,570,000**
Gas Pilots Budget	**$1,407,000**	**$1,663,000**	**$1,981,000**	**$5,051,000**

The estimates for Customer Incentives costs in the Gas DR Pilot Budget of approximately $2.9 million for the three-year Pilot period are premised on a number of factors which are outside of the Company's control. For example, while the Gas DR Pilot proposes to limit the total number of customers that can participate in the Performance-Based Gas DR Offering, the Company has not placed any limit on the amount of reduction each customer or aggregator can enroll in the Pilot. If peak day gas reductions by customers are greater than the amount the Company has anticipated, Customer Incentives costs will be greater than estimated.

As a result of this uncertainty, if incentive costs are projected to be higher than anticipated, the Company will petition for additional funding.

6.1.2 Meter Data Collection

Section 4.3.1 describes metering options for customers participating in the Performance-Based Gas DR

Offering, including two options that involve data collection by Con Edison at the premises of customers that are not equipped with gas AMI meters or customer owned interval data recording devices.

The level of expenditure that will be required for data collection by Con Edison will ultimately be determined by the level of participation in the Performance-Based Gas DR Offering. Based on expected levels of participation, Con Edison estimates that over the course of the first three years the Performance-Based Gas DR Offering will require $0.58 million for meter readings and incremental hardware, such as Field Service Units. Incremental costs for IMUs that are installed under metering Option 4 will be funded by Con Edison through its existing budget for gas AMI meter installation.

6.1.3 Customer Incentives

Section 4.3.4 describes the incentive strategy for the Performance-Based Gas DR Offering, and Section 5.1.3 outlines the incentive strategy for the DLC Gas DR Offering. The level of expenditure for customer incentives will ultimately be determined by the level of participation in the Gas DR Pilot, as well as the number of events being called each year. Based on expected levels of participation in the Gas DR Pilot, and an average number of events per year based on historical weather data, Con Edison estimates that customer incentives over the course of the first three years will amount to $2.90 million.

6.1.4 Gas DR Pilot Administration

Gas DR Pilot administration costs include expenditures that relate to the establishment and day-to-day delivery of the Gas DR Pilot and are beyond the costs of meter data collection and customer incentives. This budget includes costs for the incremental staff that will be responsible for the management of the Gas DR Pilot, incremental marketing, outreach, and other customer engagement activities, market research efforts, settlement processes, and demand response management system integration.

Pilot administration costs for the first three years of the Gas DR Pilot are estimated at $1.57 million.

6.2 Benefit-Cost Analysis

Con Edison has developed a Gas BCA Framework to provide a common methodology for calculating benefits and costs of projects and investments related to gas demand reductions and/or local supply-side additions. A program or portfolio is considered to be cost-effective when the BCA result is 1.0 or greater, i.e., providing more benefits than costs to society.

The gas BCA approach largely follows the accepted electric BCA approach. The Company used the Gas BCA Framework to evaluate the Gas DR Pilot and also plans to utilize the Gas BCA Framework to evaluate other gas programs including NPSs RFPs. Some modifications were necessary to focus on key analytical drivers including recognition of the costs and benefits of heating electrification, better capturing of the benefits of heating measures, and providing a methodology for evaluating local supply options. The Gas BCA Framework recognizes the benefits and costs of heating electrification by including summer and winter electric system costs and benefits, evaluating projects based on incremental project costs, and using a comparable CO_2 cost for electricity and gas. This methodology better captures the benefits of peak day and winter season gas load reductions by including the avoided cost of new pipeline capacity and other upstream capacity costs as a potential benefit, using seasonal commodity prices and recognizing higher peak day prices, and recognizing the potential avoided cost of on-system upgrades as a capacity metric.

The Societal Cost Test (SCT) is the primary metric used for the BCA. It includes incremental benefits to society as a whole, including CO_2 impacts when compared to the baseline alternative, and also includes the incremental project cost, including any of those costs borne by customers. Major benefit streams included in the SCT are avoided upstream pipeline capacity and delivered services costs, on-system capital costs, gas commodity costs, CO_2 emissions, electric commodity costs, electric capacity costs, and electric transmission and distribution costs.

Con Edison initially calculated the cost-effectiveness for the Performance-Based Gas DR Offering using the interim Gas BCA Framework. Under the participation assumed in this Implementation Plan, the SCT value exceeds 1.0.

Con Edison evaluated two primary scenarios for the BCA:

1. Benefit stream includes avoiding pipeline capacity costs as well as delivered services costs (BCA = 1.43).
2. Benefit stream includes only avoiding delivered services (BCA = 1.09).

Both primary scenarios assumed that the program will reach a steady state (i.e., the 10-year time period considered starts in 2021 after the Pilot is over), which means that the higher administrative costs associated with the pilot phase have been lowered and the costs associated with non-AMI meters have been eliminated. The blended 2018-2019 and 2019-2020 Zone A and Zone B incentive values are based on the current enrollments in the Company's Commercial System Relief Program.

Con Edison also initially performed a sensitivity analysis on some of the parameters used in the BCA, including the fraction of participating customers in Zone B and the time period that includes the pilot starting in 2018. The BCA exceeds 1.0 for all sensitivity runs when the avoided pipeline capacity costs were included. In the scenario where the benefit stream only includes avoiding delivered services, and not the avoided pipeline capacity, sensitivity runs with a higher proportion of participating customers in Zone B show a BCA higher than 1.0, however those runs with lower proportion of participating customers in Zone B have a BCA lower than 1.0. This is because the Zone B customers have lower incentive rates.

Table 5: Results of the initial primary BCA scenarios as well as sensitivity analyses. All values are for the SCT.

Program	Base Case: Avoid Pipeline Costs (Zone A)	Low Benefits Case: Delivered Services Only*
10 Yr Program (2021 – 2030) • 76% Zone B enrollment	1.43	1.09
10 Yr Program (2021 – 2030) • 50% Zone B enrollment	1.61	0.97
10 Yr Program (2021 – 2030) • 100% Zone B	1.22	1.22
10 Yr Program (2018 – 2027) • Includes pilot phase • Reduces admin costs starting in 2021 • 50% Zone B enrollment	1.14	0.79

Primary BCA Scenario evaluated

* Delivered Services modeled at current prices

For the 2020/2021 Winter Capability Period, Con Edison updated the incentive zones and values for the Performance Based Offering to reflect stakeholder feedback and geographically based benefits in the BCA used in the Company's recent Non-Pipelines Solutions Request for Information solicitation.[10] These incentives are set at values that are expected to continue to enable the Pilot to grow into a cost-effective full-scale program. The Pilot BCA will be re-evaluated at the end of the pilot period.

[10] https://www.coned.com/-/media/files/coned/documents/business-partners/business-opportunities/non-pipes/non-pipeline-solutions-to-provide-peak-period-natural-gas-system-relief-rfi.pdf?la=en

Appendix A. Gas DR Pilot Value Zones

Table 6 presents the zip codes by zone for determining customer incentives and eligibility for the Gas DR Pilot, as discussed in Section 4.1.

Table 6. 2020-2021 Gas DR Pilot Value Zones for Customer Incentives and Eligibility

Gas Reduction Value	ZIP	Location
Zone 1. Highest	10502	Westchester
	10503	Westchester
	10504	Westchester
	10506	Westchester
	10507	Westchester
	10510	Westchester
	10514	Westchester
	10522	Westchester
	10523	Westchester
	10528	Westchester
	10530	Westchester
	10532	Westchester
	10533	Westchester
	10536	Westchester
	10538	Westchester
	10543	Westchester
	10545	Westchester
	10549	Westchester
	10550	Westchester
	10552	Westchester
	10553	Westchester
	10562	Westchester
	10567	Westchester
	10570	Westchester
	10573	Westchester
	10577	Westchester
	10580	Westchester
	10583	Westchester
	10591	Westchester
	10594	Westchester

	10595	Westchester
	10601	Westchester
	10603	Westchester
	10604	Westchester
	10605	Westchester
	10606	Westchester
	10607	Westchester
	10610	Westchester
	10701	Westchester
	10702	Westchester
	10703	Westchester
	10704	Westchester
	10705	Westchester
	10706	Westchester
	10707	Westchester
	10708	Westchester
	10709	Westchester
	10710	Westchester
	10801	Westchester
	10802	Westchester
	10803	Westchester
	10804	Westchester
	10805	Westchester
Zone 2. Significant	11105	Queens
	11361	Queens
	11426	Queens
	11358	Queens
	11104	Queens
	11103	Queens
	11355	Queens
	11354	Queens
	11101	Queens
	11106	Queens
	11365	Queens
	11357	Queens
	11427	Queens
	11362	Queens

	11356	Queens
	11004	Queens
	11363	Queens
	11423	Queens
	11102	Queens
	11364	Queens
	11001	Queens
	11040	Queens
	11367	Queens
	11366	Queens
	11360	Queens
	11370	Queens
	11377	Queens
	11432	Queens
	11435	Queens
	11359	Queens
	11428	Queens
	11109	Queens
	11415	Queens
	11373	Queens
	11439	Queens
	11374	Queens
	11436	Queens
	11433	Queens
	10029	Manhattan
	10032	Manhattan
	10014	Manhattan
	10025	Manhattan
	10022	Manhattan
	10024	Manhattan
	10009	Manhattan
	10013	Manhattan
	10021	Manhattan
	10002	Manhattan
	10010	Manhattan
	10028	Manhattan

	10033	Manhattan
	10040	Manhattan
	10031	Manhattan
	10034	Manhattan
	10001	Manhattan
	10019	Manhattan
	10023	Manhattan
	10038	Manhattan
	10017	Manhattan
	10016	Manhattan
	10065	Manhattan
	10036	Manhattan
	10012	Manhattan
	10027	Manhattan
	10128	Manhattan
	10003	Manhattan
	10035	Manhattan
	10011	Manhattan
	10026	Manhattan
	10030	Manhattan
	10075	Manhattan
	10006	Manhattan
	10069	Manhattan
	10039	Manhattan
	10007	Manhattan
	10037	Manhattan
	10018	Manhattan
	10004	Manhattan
	10112	Manhattan
	10044	Manhattan
	10282	Manhattan
	10005	Manhattan
	10280	Manhattan
	10281	Manhattan
	10020	Manhattan
	10106	Manhattan

	10111	Manhattan
	10123	Manhattan
	10169	Manhattan
	10152	Manhattan
	10154	Manhattan
	10119	Manhattan
	10104	Manhattan
	10080	Manhattan
	10173	Manhattan
	10115	Manhattan
	10105	Manhattan
	10165	Manhattan
	10122	Manhattan
	10162	Manhattan
	10166	Manhattan
	10041	Manhattan
	10178	Manhattan
	10285	Manhattan
	10118	Manhattan
	10176	Manhattan
	10110	Manhattan
	10167	Manhattan
	10279	Manhattan
	10172	Manhattan
	10045	Manhattan
	10175	Manhattan
	10103	Manhattan
	10271	Manhattan
	10278	Manhattan
	10170	Manhattan
	10174	Manhattan
	10121	Manhattan
	10466	Bronx
	10469	Bronx
	10467	Bronx
	10464	Bronx

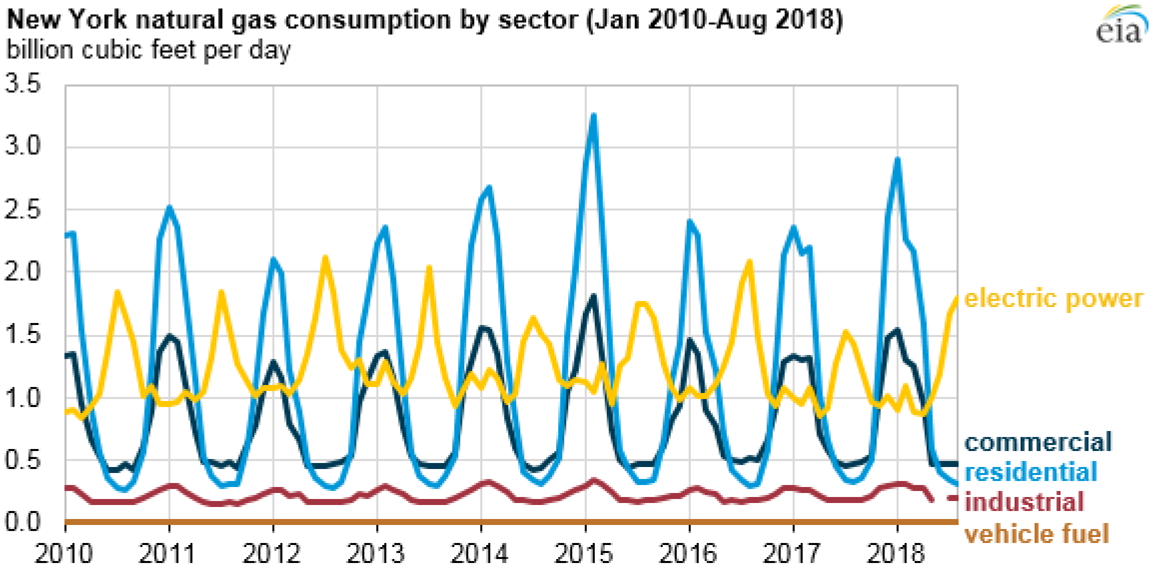
	10470	Bronx
	10452	Bronx
	10475	Bronx
	10462	Bronx
	10473	Bronx
	10465	Bronx
	10461	Bronx
	10460	Bronx
	10472	Bronx
	10453	Bronx
	10468	Bronx
	10457	Bronx
	10463	Bronx
	10451	Bronx
	10474	Bronx
	10456	Bronx
	10455	Bronx
	10454	Bronx
	10459	Bronx
	10471	Bronx
	10458	Bronx
Zone 3. Moderate	10547	Westchester
	10533	Westchester
	10514	Westchester
	10523	Westchester
	10577	Westchester
	10603	Westchester
	10601	Westchester
	10532	Westchester
	10573	Westchester
	10604	Westchester
	10703	Westchester
	10605	Westchester
	10607	Westchester
	10520	Westchester
	10548	Westchester

	10606	Westchester
	10511	Westchester
	10530	Westchester
	10583	Westchester
	10535	Westchester
	10588	Westchester
	10598	Westchester
	10595	Westchester
	10589	Westchester
	10505	Westchester
	10550	Westchester
	10580	Westchester
	10502	Westchester
	10707	Westchester
	10701	Westchester
	10549	Westchester
	10710	Westchester
	10536	Westchester
	10528	Westchester
	10594	Westchester
	10506	Westchester
	10706	Westchester
	10801	Westchester
	10805	Westchester
	10507	Westchester
	10504	Westchester
	10501	Westchester
	10517	Westchester
	10526	Westchester
	10527	Westchester
	10540	Westchester
	10596	Westchester

Today in Energy

November 2, 2018

Consolidated Edison gets approval for natural gas demand response pilot program



Source: U.S. Energy Information Administration, *Natural Gas Monthly*

In August 2018, the New York Public Service Commission approved a petition by Consolidated Edison Company of New York, Inc. (Con Edison) for a $5 million, three-year natural gas demand response pilot program, one of the first demand response projects for natural gas.

Demand response (DR) programs help manage utility usage during periods of peak demand. These programs have become fairly common in the electricity sector during the past 10 to 15 years. For the electric power sector in the United States, peak electricity demand occurs in the summer, when warm weather increases the demand for air conditioning.

Conversely, peak demand for U.S. natural gas occurs in the winter. Natural gas is used directly to heat homes and buildings and as a fuel for electricity generation. Nearly 60% of New York homes used natural gas as their primary heating fuel in 2017, based on data from the U.S. Census Bureau's American Community Survey.

Con Edison has firm pipeline transport contracts that enabled the company to meet 83% of its peak-day demand in the winter of 2017–2018. Firm contracts provide Con Edison with an agreed-upon supply of natural gas that cannot be curtailed except under unforeseeable circumstances. To meet the rest of its peak-day natural gas demand, Con Edison purchases delivered services (also known as peaking contracts) from other companies. Unlike firm transport contracts, which generally have renewal rights, delivered services are not guaranteed to be available in any given year, especially if competing natural gas use elsewhere continues to increase.

According to Con Edison, firm natural gas demand on its peak day increased by more than 30% between 2011 and 2017, and it expects the peak to grow by an additional 23% during the next 20 years. The increasing peak is driven by a preference for natural gas heat in new buildings and the switch from heating oil to natural gas in existing facilities. This transition is a result of both a 2011 mandate to reduce the use of heavy heating oil (No. 6 fuel oil) in New York City and the general decline in natural gas prices since 2011.

Con Edison estimates that, by the winter of 2023–2024, its firm pipeline contracts will meet only 78% of its peak-day demand absent any new pipeline capacity. However, no remaining firm pipeline capacity is currently available into New York City or Westchester County, and recent attempts to add pipeline capacity have stalled as a result of regulatory challenges. Con Edison is now planning alternative measures, including DR, to reduce reliance on interruptible contracts and to help ensure all its customers are served on the coldest days of the year.

In its pilot program, Con Edison proposed two methods of natural gas DR that closely match its existing electricity DR programs. For residential and small commercial customers, it proposed using direct load control to adjust customers' thermostats during peak natural gas demand days, with financial incentives for participation offered for up to 1,000 customers through 2021.

For industrial, large commercial, and multi-family residential customers with centralized boilers, Con Edison proposed to achieve demand reductions through financial incentives alone when peak demand days are forecast. The company aims to enroll 500 new customers each year in this portion of the pilot program.

Although DR has become fairly common in the electricity sector, programs to reduce natural gas demand have only recently been adopted. In early 2017, Southern California Gas Company (SoCalGas) piloted the Seasonal Savings program, which used direct load control to adjust about 50,000 residential thermostats according to a household's schedule and preferences to reduce short-term peak demand. In the winter of 2017–2018, 16 National Grid customers in New York City and Long Island participated in a DR program aimed at commercial and industrial customers, where large heaters or machinery running on natural gas were turned on and off to manage peak demand days.

Principal contributor: David Manowitz

New Jersey Natural Gas

New Jersey Natural Gas Partners with Google and EFI to Provide Nearly Half a Million Free Smart Thermostats To New Jersey Households During Pandemic

06/08/2020 - For Immediate Release

WALL, N.J., June 8, 2020 – New Jersey Natural Gas (NJNG) today announced it has partnered with Google Nest and Energy Federation Inc. (EFI) to provide the Google Nest Thermostat E at no cost to NJNG's nearly half a million residential customers*, helping households save energy and money.

This offer reinforces NJNG's commitment to sustainability and delivering energy-efficiency solutions to help customers make energy decisions that save energy, lower energy bills and reduce carbon emissions.

"With customers spending more time at home in response to COVID-19, and warmer weather on the way, energy use and bills will be on the rise," said Steve Westhoven, president and CEO of New Jersey Resources, parent company of NJNG. "We're here to help our customers by empowering them with the technology and tips they need to save energy and money, and help protect the environment."

Nest Thermostat E users save an average of up to 15% on cooling costs and up to 12% on heating costs**, according to Google. Based on typical energy usage, this translates to an estimated average savings of $131 - $145 each year. The free Nest Thermostat E offer complements NJNG's overarching efforts to provide customers with access to programs to help manage their energy bills.

- The Nest Thermostat E automatically programs itself and creates a schedule based on the user's habits and preferences.
- With voice activation capabilities, it is easier than ever to save energy and stay comfortable.
- The Nest Leaf icon appears on the thermostat device, or app, to indicate when energy-saving temperatures are selected.

The limited-time offer is valid June 8 through July 20, 2020 for NJNG customers only on the NJNG Marketplace. Customers can visit njng.com/marketplace for this free offer and discounts on other energy-efficiency products. The NJNG Marketplace was launched in 2019 in conjunction with EFI, which provides the e-commerce technology for the NJNG Marketplace and fulfillment services to NJNG clients.

NJNG's The SAVEGREEN Project® offers rebates and incentives, including 0% APR financing, to help make it affordable to replace HVAC and water heating equipment – with the potential of no upfront costs.*** Plus, enhanced rebates and financing terms are available for eligible moderate-income customers. Visit savegreenproject.com to learn more.

NJNG reminds its customers energy assistance programs are available. If you or someone you know needs assistance paying their NJNG bill, call **800-221-0051** and say "energy assistance" at the prompt to speak with an NJNG customer service representative or email us at energyassist@njng.com.

Google Nest and Google Nest Thermostat E are trademarks of Google LLC.

* Smart thermostats must be purchased through the NJNG Marketplace and are only available to NJNG customers. NJNG instant rebate limited to the purchase of two thermostats only over the lifetime of the NJNG Marketplace. Smart thermostats are not compatible with all heating systems. Price reflects NJNG and manufacturer rebates. Customers are responsible for all applicable sales tax. Terms and conditions apply.

** Independent studies showed that Google Nest saved an average of 10% to 12% on heating and 15% on cooling. Based on typical energy costs, that's an estimated average savings of $131 to $145 a year. Individual savings not guaranteed.

*** Visit savegreenproject.com for terms and conditions.

About New Jersey Resources:

NJR is a Fortune 1000 company that, through its subsidiaries, provides safe and reliable natural gas and clean energy services, including transportation, distribution, asset management and home services. It is composed of five primary businesses:

- **New Jersey Natural Gas**, NJR's principal subsidiary, operates and maintains over 7,500 miles of natural gas transportation and distribution infrastructure to serve over half a million customers in New Jersey's Monmouth, Ocean, Morris, Middlesex and Burlington counties.
- **NJR Clean Energy Ventures** invests in, owns and operates solar projects with a total capacity of over 315 megawatts, providing residential and commercial customers with low-carbon solutions.
- **NJR Energy Services** manages a diversified portfolio of natural gas transportation and storage assets and provides physical natural gas services and customized energy solutions to its customers across North America.
- **NJR Midstream** serves customers - from local distributors and producers to electric generators and wholesale marketers through its ownership of Leaf River Energy Center and the Adelphia Gateway Pipeline Project, as well as a 50 percent equity ownership in Steckman Ridge natural gas storage facilities, and a 20 percent equity interest in the planned PennEast Pipeline Project.
- **NJR Home Services** provides service contracts as well as heating, central air conditioning, water heaters, standby generators, solar and other indoor and outdoor comfort products to residential homes throughout New Jersey.

NJR and its more than 1,100 employees are committed to helping customers save energy and money by promoting conservation and encouraging efficiency through Conserve to Preserve® and initiatives such as The SAVEGREEN Project® and The Sunlight Advantage®. For more information about NJR: www.njresources.com.

Follow us on Twitter @NJNaturalGas.

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Contact:

Kevin Roberts, Media Contact
732-938-1197

Dennis Puma, Investor Contact

732-938-1229

Return to Listing

SmartGrid consumer collaborative

2016 MEMBERS MEETING & Interactive Workshop

Chicago, Illinois | September 21–22, 2016

ComEd’s Million Thermostat Program

ComEd's Million Thermostat Program

Val Jensen

Senior VP, Customer Operations

ComEd

Hannah Bascom

Business Development Director

NEST

A Million Smart Thermostats

Val Jensen, SVP Customer Operations, ComEd
Hannah Bascom, Head of East Coast Partnerships, Nest

ComEd
An Exelon Company

Realize the installation of 1 million smart thermostats over the next 5 years

- A communicating thermostat that can sense occupancy and set back temperature setpoints accordingly
- Wi-Fi enabled and controllable through a remote device.
- Connected to continuous 24 volt power supply source (through common wire or adapter).
- Incorporates occupancy based controls.
- Compatible with multi-stage heating and cooling units.
- Two year product warranty.

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DELIVERY CHANNELS AND INCENTIVES

smart ideas
ComEd® Energy Efficiency Program

THREE WAYS TO GET YOUR SMART THERMOSTAT

ComEd Smart Ideas® Energy Efficiency Program
offers rebates and discounts on smart thermostats.*

SMART THERMOSTATS	
Self-installed Purchase and install your qualifying smart thermostat and receive a $100 rebate from ComEd.	**ecobee3, Nest Learning Thermostat** $100 rebate
Contractor-installed Use a professional contractor to install your qualifying smart thermostat and receive a $125 rebate from ComEd.	**ecobee3, Honeywell Lyric, Nest Learning Thermostat** $125 rebate
Utility-installed Receive a smart thermostat at the discounted price of $150, including free installation during your Home Energy Assessment.	**ecobee3** $150 discounted price

*Some restrictions may apply.
Additional rebates may be available from Nicor Gas, North Shore Gas and Peoples Gas. Visit gas utility websites for details.

For more information call 855-433-2700 or visit ComEd.com/Rebates or ComEd.com/Assessment

Smart Ideas® Energy Efficiency Program is funded by ComEd customers in compliance with Illinois law.

ComEd. An Exelon Company | powering lives

ComEd. An Exelon Company

Why a million?

No finite point has meaning without an infinite reference point.

Jean-Paul Sartre

And a million thermostats is close to infinity

WHY SMART THERMOSTATS?

Utility Wasted Energy Studies

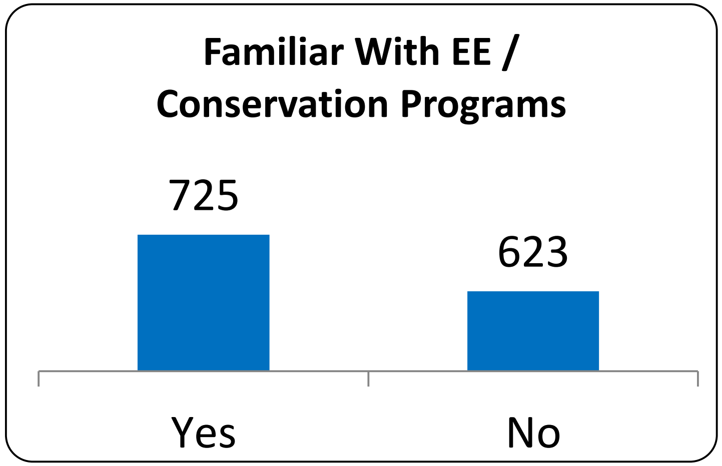
- **ComEd Wasted Energy Study:**
  - "Cooling has the greatest opportunities to reduce behavioral waste, which accounts for 38% of current usage, mainly by increasing temperature setpoints."

- **Peoples Gas and North Shore Gas Wasted Energy Studies**:
  - Thermostat setback behavior change potential: 6%

- **Potential for additional energy savings beyond that of a Programmable Thermostat**

Smart Thermostats are the most recognizable EE measure after the light bulb and represent a design and operational break with traditional EE


Business updated: 10/8/2015 1:09 PM
New smart thermostat program aims to save energy, costs
The Nest smart thermostat is among the newest devices available with rebates to consumers.
COURTESY OF NEST



wttw11

WTTW 11 Chicago Tonight
Coverage of Smart Thermostats

NBC 5 News at 5
Coverage of Smart Thermostats


Business updated: 10/8/2015 1:09 PM
New smart thermostat program aims to save energy, costs
The Nest smart thermostat is among the newest devices available with rebates to consumers.
COURTESY OF NEST

"New smart thermostat program aims to save energy, costs."
– *Daily Herald*


Energy and Environment
Chicago's top power company wants to install a million smart thermostats in homes by 2020
The single biggest way we use energy in our homes is through heating in

"Chicago's top power company wants to install a million smart thermostats in homes by 2020."
– *Washington Post*

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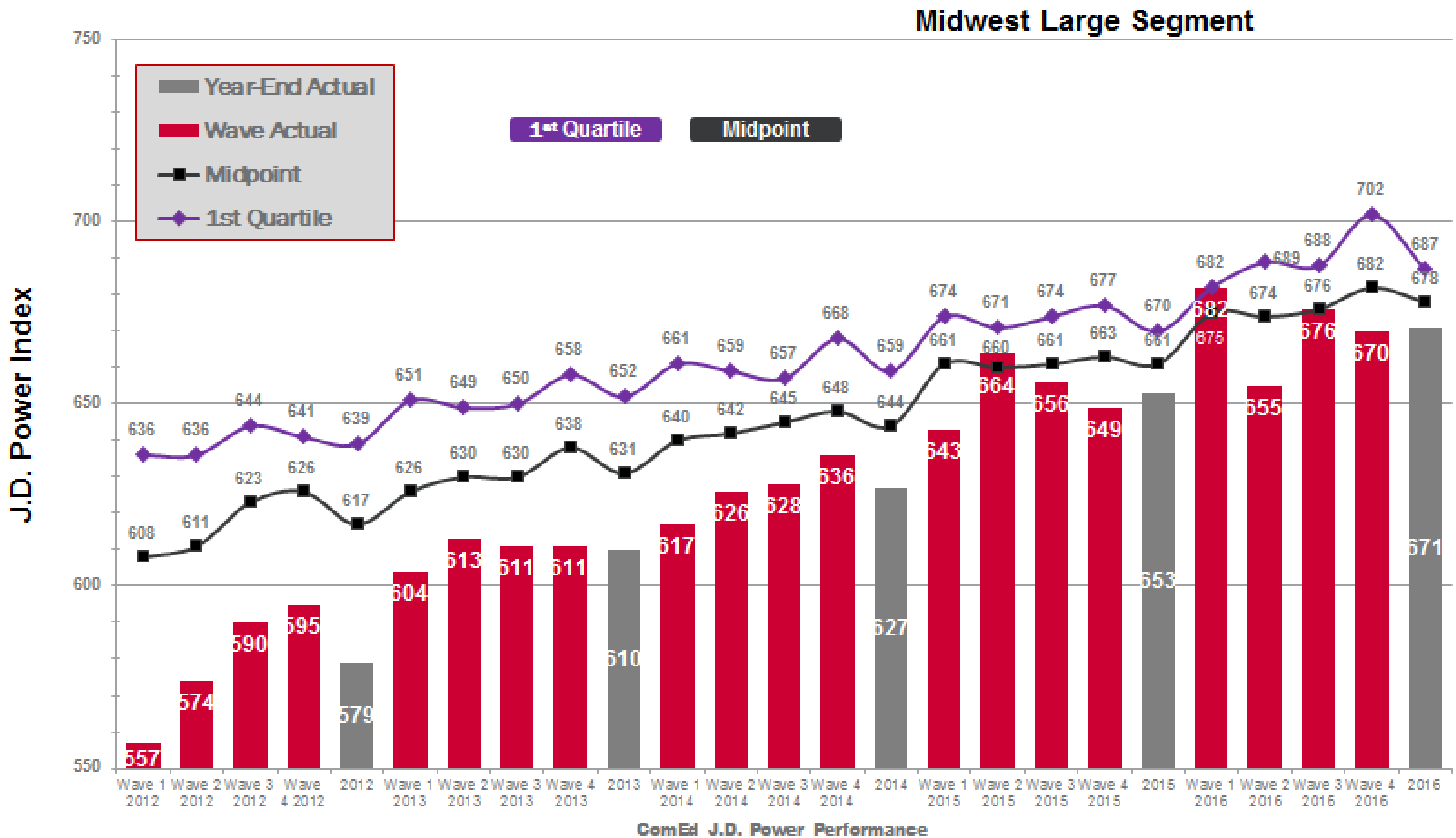
Reason #1: Boost Customer Satisfaction

2012 – 2016 J.D. Power Performance – ComEd



ComEd
An Exelon Company

Reason #2: The need for a new approach

- ✓Residential savings peaking
  - Lighting per unit savings declining
  - Appliance programs very expensive
  - Standard behavioral programs close to saturation
- ✓Needed to reduce administrative costs
- ✓Needed to find a way to increase leverage

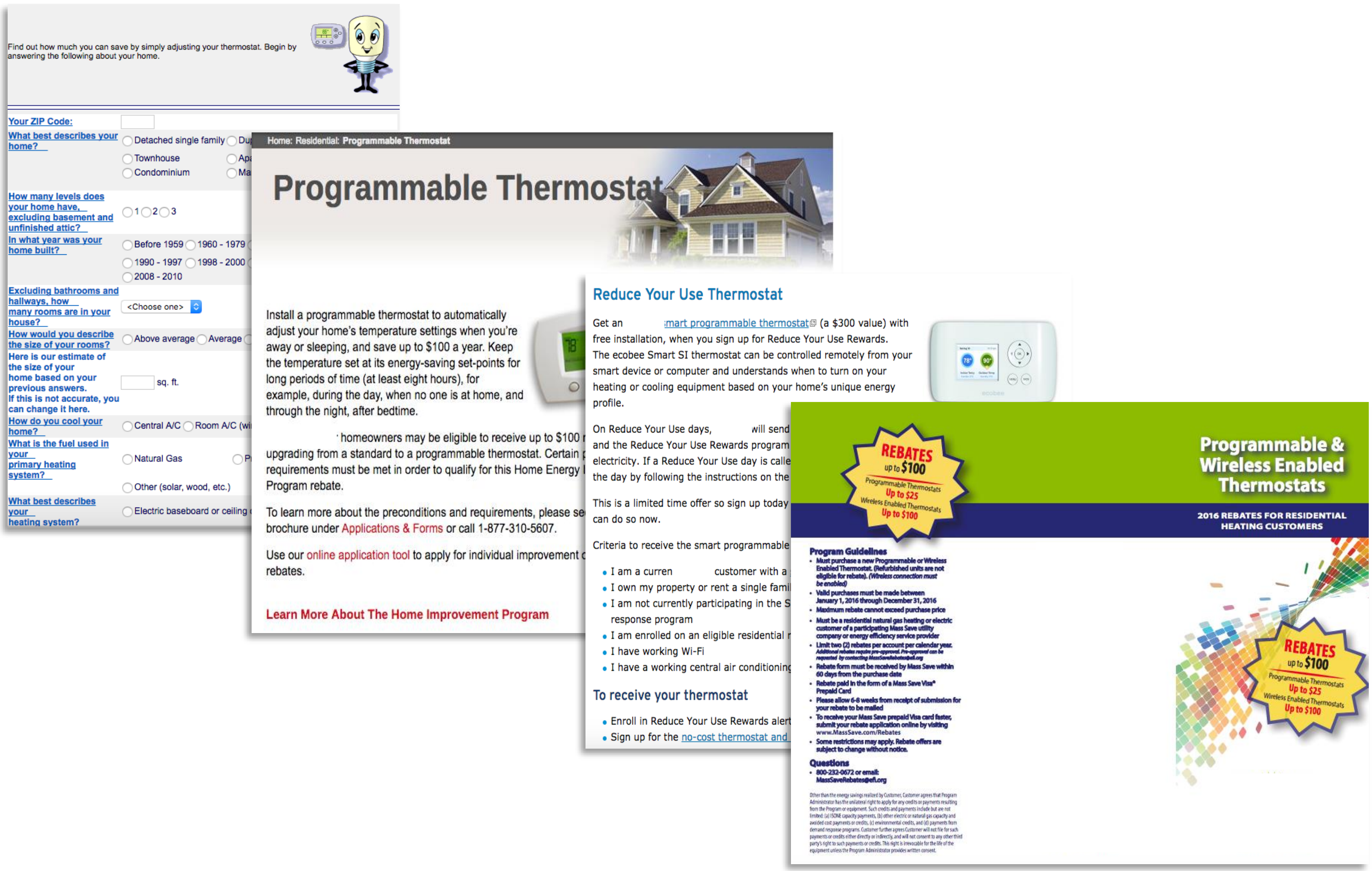
How do you sell a Million Smart thermostats…

And enable the transformation of:

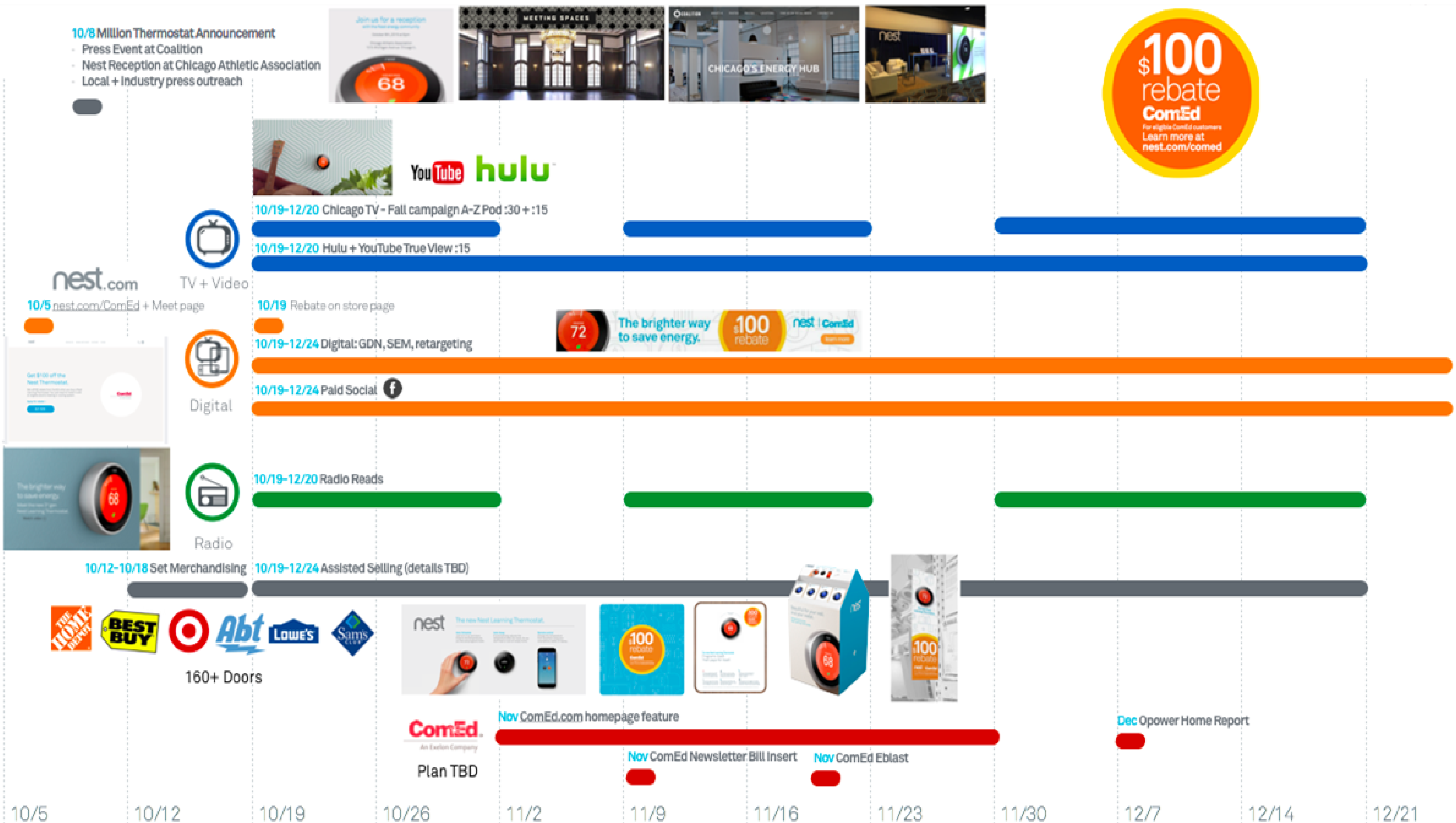
- A utility rebate program
- Consumer perception of a utility
- The way customers control their energy usage


nest
COOLING
75
78
Y1
Y2
G
RC
C
RH

Reinventing utility program marketing…



With a consumer products approach

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Starting At
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$9.97
$34.9
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$100
rebate


68
The new
Nest Learning Thermostat.
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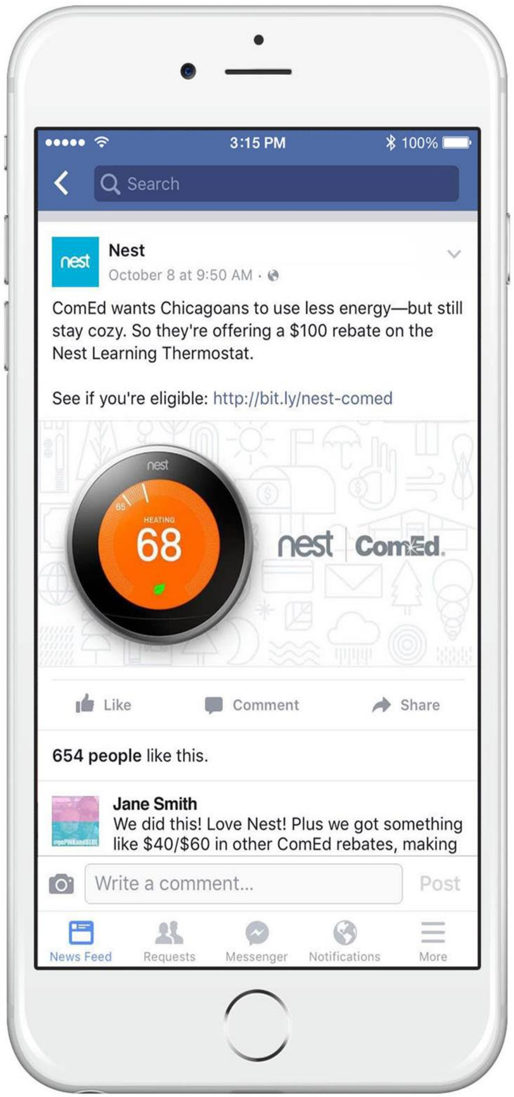
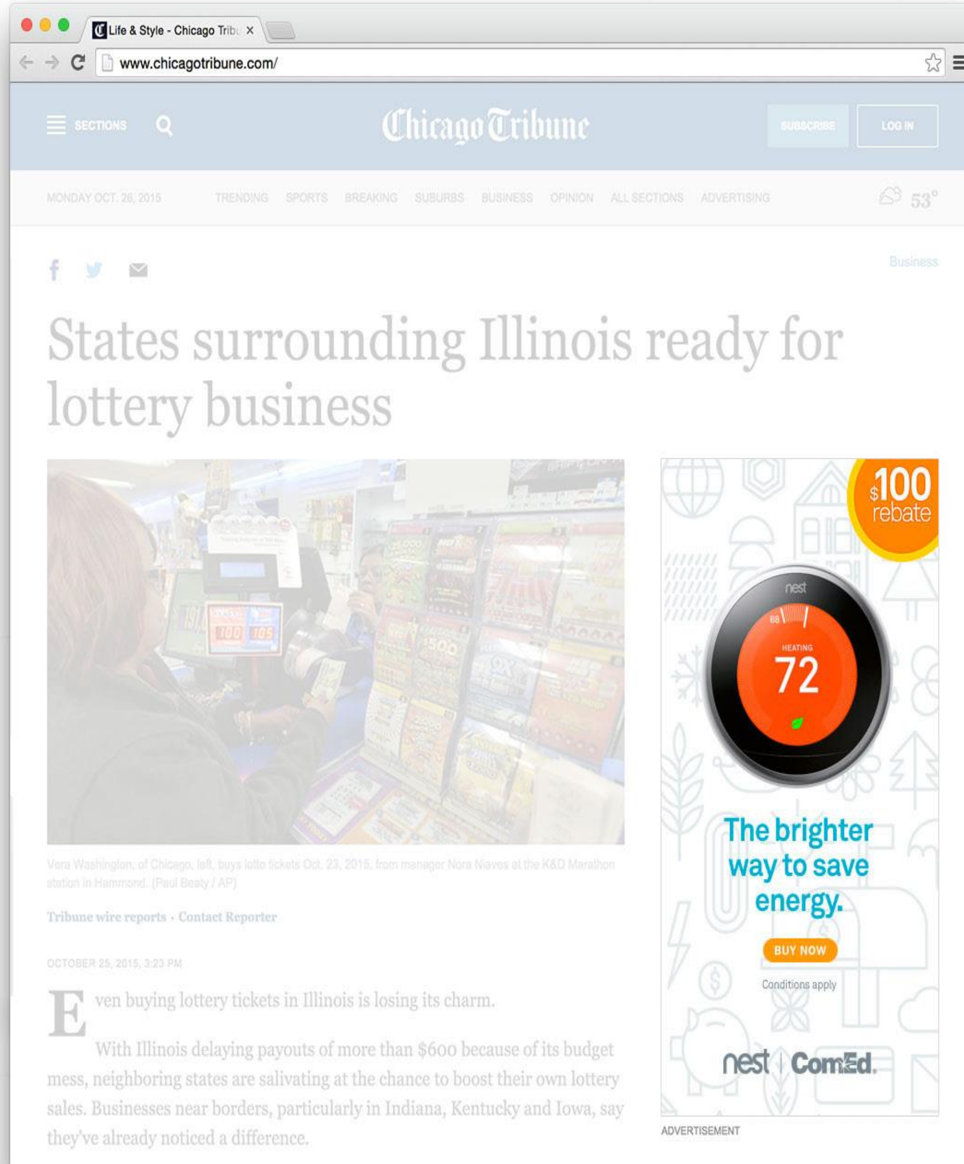
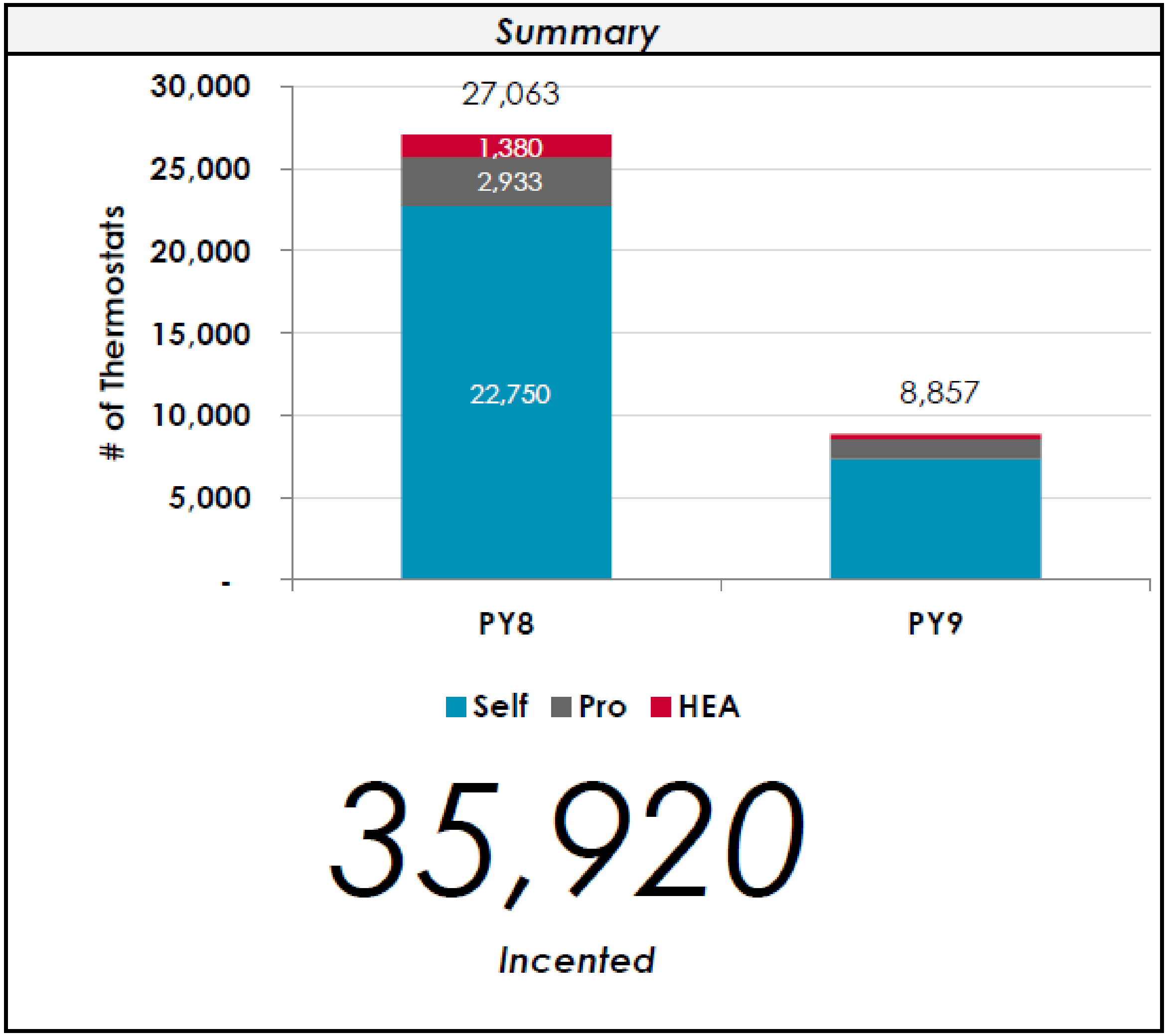




10 months in, how is it going?

How are we doing?



FREE IN-HOME ASSESSMENT REGISTRATION

A free thermostat can:

- Programs itself and helps save energy
- Save on average of 10% to 12% on heating bills
- Save on average of 15% on cooling bills

Smart Products for your home isn't just easier on the environment; it also saves you money!

First Name

Last Name

Reference number

Phone number

Email

Date of Birth

City

Address

Province

Appointment Date

Best Time To Be Reached Between

I confirm that I am the homeowner for the address above.

I confirm that I have read, understood and agree to Ontario Green Savings terms and conditions

You agree to receive Ontario Green Savings' newsletter and communications containing news, updates and promotions which may be of interest to y
unsubscribe at any time.

By completing this request for a quote/in-home visit and voluntarily providing your personal information, you consent to the collection and use of such
purposes of responding to your request and assisting with the in-home sales appointment for purchase/lease of any HVAC, water treatment or air trea
scheduled. For greater certainty, you have initiated contact and requested and authorized morConnect to attend your house to explain its purchase/le

SUBMIT

By completing this request for a quote/in-home visit and voluntarily providing your personal information, you consent to the collection and use of such information by us only for the purposes of responding to your requ
appointment for purchase/lease of any HVAC, water treatment or air treatment products you have scheduled. For greater certainty, you have initiated contact and requested and authorized Ontario Green Savings to a
programs.

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When you invest in an energy efficient home, the benefits are tremendous.

Ontario Green Savings also provides green energy products that provide a real and convenient solution for consumers to offset the environmental impact associated with their everyday energy use.

Nest Thermostat 3rd Gen

The Nest Learning Thermostat automatically adapts as your life and the seasons change. Just use it for a week and it programs itself.

The Nest Learning Thermostat is the first thermostat to get ENERGY STAR certified. Since 2011, the Nest Thermostat has saved billions of kWh of energy in millions of homes worldwide.

- ✓ Programs itself. Helps save energy.
- ✓ Save on average of 10% to 12% on heating bills
- ✓ Save on average of 15% on cooling bills.

See More ›

Reviews submitted by verified Nest users.

"Great system! I am a new homeowner and wanted to upgrade to a nicer, newer look. I love the screen and display- very similar to my iPhone and very easy to use. The Eco feature is great and I love that I can control the system from my phone while I'm not home. I sometimes turn on the system when I leave work so when I walk in the door, it's nice and toasty! Overall, without question would recommend" - **Broden F**

SEE MORE NEST THERMOSTAT REVIEWS

The Nest Thermostat E is ready to go with an easy schedule. And with the same proven energy-saving features as the Nest Learning Thermostat, you can save right from the start.

You can control it from anywhere. And its frosted display is beautifully designed to blend right in.

- ✓ It's more affordable, more visually pleasing
- ✓ It uses your phone's location to know you're away.
- ✓ Turn it up or down from anywhere.

See More ›

Nest Thermostat
Nest E

Reviews submitted by verified Nest users.

"*Nest E + remote thermostat for the win! My thermostat is mounted on a cold wall. My old thermostat would behave badly when the temperature dropped. With the Nest E, I was able to purchase and configure a remote thermostat and I made that my primary and mounted it on an interior wall. Problem solved! I also love the new look and how it blends into my light-colored walls.*" - **Rickypoo**

SEE MORE NEST THERMOSTAT REVIEWS

Ecobee4

Most thermostats only read the temperature in one place (usually the hallway) which can make other rooms uncomfortable. ecobee4 comes with a room sensor to help manage hot or cold spots.When you place sensors in your favorite rooms, ecobee4 can read the temperature and detect occupancy. That's how it ensures comfort in the rooms that matter.

- ✓ Save up to 23%* in heating and cooling costs each year.
- ✓ Amazon Alexa Voice Service built inside

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