Smart Thermostat Time-of-Use Automation Study

ET Project Number: ET21PGE7320

Pacific Gas and Electric

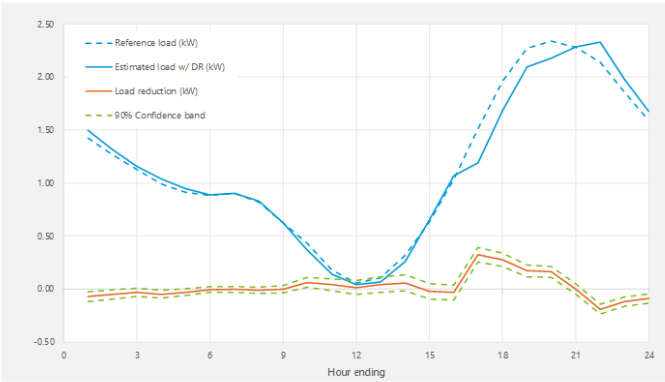
PowerSaver Rewards 2021 TOU Automation Load Impacts (Does not include incremental event-based response)

Table 1: Menu options

Program	Powersaver Rewards
Data source	AMI
Method	Difference-in-differences
Type of result	Per customer
Day Type	PG&E TOP 20 DAYS
Category	ALL
Subcategory	All

Table 2: Peak Window and Participant information

Total sites	2,387
Peak Period window temperature (F)	89.1
Max demand reduction during peak (k	0.32
Average reduction during peak (kW)	0.19
Average % load reduction	9.9%



Hour ending	Reference load (kW)	Estimated load w/ DR (kW)	Load reduction (kW)	% Load reduction	Avg temp (F, site weighted)	90% Confidence Interval 5th	90% Confidence Interval 95th	Std. error	T-statistic
1	1.42	1.50	-0.07	-5.0%	69.9	-0.12	-0.02	0.028	-2.50
2	1.27	1.32	-0.05	-3.9%	68.5	-0.09	-0.01	0.026	-1.89
3	1.13	1.16	-0.03	-2.7%	67.2	-0.07	0.01	0.024	-1.25
4	0.99	1.04	-0.05	-5.1%	66.2	-0.09	-0.01	0.022	-2.24
5	0.92	0.95	-0.03	-3.3%	65.2	-0.06	0.00	0.019	-1.61
6	0.88	0.89	0.00	-0.5%	64.5	-0.03	0.02	0.017	-0.28
7	0.90	0.90	0.00	-0.4%	63.9	-0.03	0.02	0.017	-0.21
8	0.82	0.83	-0.01	-1.4%	63.6	-0.04	0.02	0.017	-0.65
9	0.63	0.63	0.00	-0.2%	66.3	-0.03	0.03	0.021	-0.05
10	0.43	0.37	0.06	14.4%	70.5	0.02	0.11	0.028	2.22
11	0.18	0.14	0.04	22.8%	75.2	-0.01	0.10	0.034	1.21
12	0.06	0.04	0.01		79.7	-0.05	0.08	0.040	0.37
13	0.11	0.06	0.04	38.7%	83.9	-0.03	0.11	0.044	0.93
14	0.32	0.26	0.06	18.4%	87.5	-0.02	0.13	0.046	1.28
15	0.64	0.66	-0.02	-3.4%	90.5	-0.10	0.05	0.045	-0.47
16	1.03	1.07	-0.03	-3.2%	92.2	-0.11	0.04	0.044	-0.76
17	1.51	1.19	0.32	21.3%	93.0	0.25	0.39	0.042	7.65
18	1.96	1.69	0.28	14.0%	92.6	0.21	0.34	0.037	7.38
19	2.27	2.10	0.17	7.6%	90.7	0.12	0.23	0.034	5.13
20	2.34	2.18	0.16	6.9%	87.0	0.11	0.21	0.030	5.36
21	2.28	2.28	0.00	-0.1%	82.2	-0.05	0.04	0.028	-0.08
22	2.14	2.33	-0.19	-8.9%	78.0	-0.24	-0.14	0.028	-6.73
23	1.86	1.98	-0.12	-6.5%	75.2	-0.16	-0.08	0.027	-4.44
24	1.59	1.68	-0.09	-5.6%	72.9	-0.13	-0.05	0.026	-3.49
Daily	Reference load (kWh)	Estimated load w/ DR (kWh)	Energy savings (kWh)	% Change	Avg. Daily Weighted temp (F)	Uncertainty adjusted impact - Percentiles 5th	Uncertainty adjusted impact - Percentiles 95th	Std. error	T-statistic
Daily kWh	27.67	27.23	0.44	1.6%	76.94	0.18	0.69	0.15	2.84
Peak (4-9 PM)	2.07	1.89	0.19	9.9%	89.11	0.15	0.22	0.019	9.59

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Together, Building a Better California

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Legal Notice

ABBREVIATIONS AND ACRONYMS

EE	Energy Efficiency
DR	Demand Response
kW	Kilowatts
MW	Megawatts
TOU	Time-of-Use

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EXECUTIVE SUMMARY

This report presents the results of PG&E's Smart Thermostat Time-of-Use (TOU) Automation Study with a bring your own thermostat program design. The study provided incentives to residential customers who allowed PG&E to reduce or shift their electricity use in the 4–9 pm peak hours by communicating with WiFi-enabled smart thermostats. In 2021, PG&E tested three types of connected thermostats – Nest, Ecobee, and Emerson – that reduce or shift electricity during demand response (DR) events. In addition, two thermostat manufacturers – Ecobee and Emerson – also allowed customers to automate daily response to TOU rates.

The primary objectives of this study were to:

- Understand how enrollment rates vary by thermostat brand and what share of customers elect the daily TOU automation option.
- Quantify the magnitude of thermostat-enabled daily TOU demand reduction over and above customer behavioral response to the rates.
- Quantify the magnitude of dispatchable demand reduction for each event called over and above customer and thermostat daily response to TOU rates.
- Understand how dispatchable reduction vary as a function of weather, event start, hours into the event, and daily TOU automation.
- Understand how demand daily and event-based demand reduction vary across customers by geography, income status, solar, number of devices at site, and thermostat brand.
- Assess demand reduction persistence across the event hours.

The study launched mid-summer, and PG&E recruited 11,320 residential sites with 13,744 controllable thermostats by September 30, 2021. The dispatchable events analysis relied on randomized control trial where treatment and control sites were randomly assigned for each event. PG&E called a total of 14 events over the course of half a summer. By design, PG&E called events over a wide range of weather conditions, event start times, and even event durations. The dispatchable event impacts were estimated using whole-home hourly data and a difference-in-difference panel regression. The daily TOU automation analysis included over 3,600 and was analyzed using a matched control group and difference-in-differences. The control group was selected from a pool of ecobee participants without TOU automation using propensity score matching.

Table 1 summarizes the demand reduction from daily TOU automation, excluding any dispatchable event days. Table 2 summarizes the event-based demand reduction over and above reduction from daily TOU automation. For sites with TOU automation, the overall demand reduction are the sum of daily shifting and the incremental dispatchable load impacts. Table 3 summarizes the event day results for sites that did not automate their thermostats to deliver daily TOU automated response. Table 4 summarizes the key findings from the study.

Table 1: Daily TOU Automation Load Impact Summary

System	Day Type	Accounts (Average)	Max Temp (Participant weighted)	4:00-5:00 PM	5:00-6:00 PM	6:00-7:00 PM	7:00-8:00 PM	8:00-9:00 PM	Average 4-9 PM
ALL	AVERAGE DAY JULY	1,712	90.2	0.25	0.30	0.21	0.16	-0.05	0.17
	AVERAGE DAY AUGUST	2,353	87.9	0.26	0.27	0.18	0.13	0.04	0.18
	AVERAGE DAY SEPTEMBER	2,530	83.7	0.09	0.09	0.01	0.04	-0.07	0.03
PG&E	PEAK DAY JULY	132	97.6	0.06	0.36	0.47	0.21	-0.06	0.21
	PEAK DAY AUGUST	2,278	94.0	0.37	0.29	0.23	0.21	0.05	0.23
	PEAK DAY SEPTEMBER	2,269	93.4	0.17	0.17	0.01	0.04	-0.01	0.08
	TOP 10 DAYS	2,062	91.6	0.38	0.26	0.33	0.27	-0.05	0.24
	TOP 20 DAYS	2,387	93.0	0.32	0.28	0.17	0.16	0.00	0.19
CAISO	PEAK DAY JULY	1,174	90.0	0.17	0.18	0.13	0.11	-0.02	0.11
	PEAK DAY AUGUST	2,293	93.3	0.41	0.32	0.24	0.22	0.00	0.24
	PEAK DAY SEPTEMBER	2,265	87.6	0.08	0.20	0.01	0.02	0.02	0.07
	TOP 10 DAYS	2,382	92.4	0.29	0.29	0.19	0.18	0.04	0.20
	TOP 20 DAYS	2,387	91.1	0.32	0.32	0.19	0.17	-0.03	0.19
CAISO Net Loads	PEAK DAY JULY	1,471	92.6	0.31	0.31	0.19	0.18	-0.29	0.14
	PEAK DAY AUGUST	2,293	92.8	0.37	0.30	0.23	0.21	0.03	0.23
	PEAK DAY SEPTEMBER	2,269	93.4	0.17	0.17	0.01	0.04	-0.01	0.08
	TOP 10 DAYS	2,381	93.9	0.26	0.23	0.11	0.11	0.15	0.17
	TOP 20 DAYS	2,603	91.5	0.29	0.24	0.14	0.15	0.00	0.16

Table 2: Event Day Demand Reduction (Sites with Daily TOU Automation)

						Hourly Impacts				Event Average				
Date	Event Start	Event hours Avg. Temp	Max Temp (Participant weighted)	Treatment Sites	Control Sites	Hour 1	Hour 2	Hour 3	Hour 4	Reference Load (Baseline)	Impact	% Impact	se	t
7/29/2021	7:00 PM	86.7	93.1	2,361	-	0.69	0.46			2.33	0.58	24.7%	0.052	11.04
7/30/2021	3:00 PM	92.6	93.1	1,875	589	1.03	0.36	0.30		1.40	0.56	40.0%	0.068	8.25
8/11/2021	4:00 PM	91.2	92.4	2,342	603	0.75	0.39	0.31		1.55	0.48	31.0%	0.063	7.60
8/12/2021	4:00 PM	89.2	89.9	2,379	600	0.48	0.20			1.25	0.34	27.1%	0.064	5.31
8/14/2021	4:00 PM	90.1	91.4	2,416	611	0.56	0.23	0.20		1.65	0.33	20.0%	0.067	4.91
9/3/2021	6:00 PM	78.3	84.6	2,821	640	0.22	0.15	0.12		1.31	0.16	12.4%	0.049	3.32
9/5/2021	6:00 PM	86.7	94.5	2,834	627	0.60	0.31	0.25		1.99	0.39	19.5%	0.061	6.34
9/7/2021	5:00 PM	89.2	95.8	2,834	624	0.75	0.42	0.28	0.25	2.17	0.42	19.4%	0.059	7.19
9/8/2021	6:00 PM	86.2	96.7	2,833	625	0.53	0.33	0.26		2.39	0.37	15.7%	0.059	6.29
9/13/2021	5:00 PM	87.3	90.4	2,770	574	0.56	0.35	0.11		1.77	0.34	19.1%	0.051	6.69
9/14/2021	4:00 PM	88.8	89.0	2,713	628	0.42	0.16			1.24	0.29	23.7%	0.053	5.53
9/21/2021	4:00 PM	90.7	93.8	3,080	606	0.54	0.32	0.23	0.17	1.48	0.32	21.3%	0.052	6.14
9/23/2021	3:00 PM	90.5	91.3	3,108	578	0.75	0.32	0.22		1.01	0.43	42.9%	0.054	7.96
10/4/2021	4:00 PM	86.6	88.1	3,734	-	0.32	0.14	0.12		1.12	0.19	17.3%	0.023	8.26
Average Event		88.1	91.7	2,721	522	0.59	0.30	0.22	0.21	1.64	0.37	22.7%	0.056	6.58

Table 3: Event Day Demand Reduction (Sites without Daily TOU Automation)

						Hourly Impacts				Event Average				
Date	Event Start	Event hours Avg. Temp	Max Temp (Participant weighted)	Treament Sites	Control Sites	Hour 1	Hour 2	Hour 3	Hour 4	Reference Load (Baseline)	Impact	% Impact	se	t
7/29/2021	7:00 PM	88.4	94.7	1,594	-	0.96	0.64			2.43	0.80	32.9%	0.058	13.77
7/30/2021	3:00 PM	94.0	94.5	1,486	686	0.91	0.76	0.49		2.00	0.72	36.1%	0.065	11.07
8/11/2021	4:00 PM	94.5	95.6	2,873	1,048	1.33	0.94	0.53		2.19	0.93	42.6%	0.051	18.17
8/12/2021	4:00 PM	92.1	92.6	2,901	1,091	0.92	0.65			1.89	0.78	41.6%	0.051	15.37
8/14/2021	4:00 PM	93.7	94.9	2,995	1,103	1.04	0.68	0.42		2.16	0.71	33.0%	0.054	13.22
9/3/2021	6:00 PM	79.5	85.3	4,547	1,410	0.45	0.28	0.21		1.33	0.31	23.6%	0.033	9.63
9/5/2021	6:00 PM	87.9	95.0	4,551	1,426	0.75	0.45	0.28		1.88	0.49	26.4%	0.041	11.98
9/7/2021	5:00 PM	90.2	96.4	4,557	1,434	1.19	0.76	0.45	0.31	2.31	0.68	29.3%	0.041	16.36
9/8/2021	6:00 PM	87.6	97.4	4,565	1,437	0.95	0.55	0.38		2.43	0.63	25.8%	0.042	15.00
9/13/2021	5:00 PM	88.3	91.1	4,492	1,439	0.82	0.50	0.28		1.87	0.53	28.5%	0.035	15.22
9/14/2021	4:00 PM	89.8	90.0	4,526	1,428	0.73	0.51			1.60	0.62	38.8%	0.037	16.94
9/21/2021	4:00 PM	90.7	93.9	5,850	1,693	0.71	0.54	0.35	0.22	1.61	0.45	28.2%	0.032	14.17
9/23/2021	3:00 PM	90.5	91.3	5,823	1,719	0.61	0.57	0.43		1.23	0.54	43.8%	0.033	16.46
10/4/2021	4:00 PM	86.6	88.0	7,669	-	0.47	0.37	0.25		1.25	0.37	29.4%	0.015	24.26
Average Event		89.6	92.9	4,174	1,137	0.85	0.59	0.37	0.26	1.85	0.59	31.8%	0.044	13.43

Table 4: Key Findings Summary

Key Finding	Additional Detail
Of the 11,300 sites enrolled, 55.8% had ecobee thermostats, 5.2% had Emerson thermostats, and 39% had Nest thermostats.	The thermostat manufacturers offered the program directly to PG&E customers in addition to PG&E recruitment. Typically, Nest devices outnumber ecobee devices, but marketing for ecobee devices launched earlier in the study (late July versus mid-August) and no other DR providers had previously tapped into the ecobee population in PG&E territory. While the manufacturers did not share all details about their marketing efforts, ecobee devices allowed in-app enrollment while Nest routed to a Nest website and Emerson devices routed customers to the implementation vendor's enrollment web page.
57.9% of ecobee participants elected to automate their daily TOU response and set their preferences for tradeoffs between comfort and savings.	Emerson also offered daily TOU automation to participants but managed to enroll only 7.6% of participants in that option. Nest thermostats did not offer a daily TOU automation option in 2021. Customers who elected for thermostat TOU automation self-identified their rate (sometimes incorrectly). When the study was implemented, PG&E had not yet fully implemented default TOU. Of the participants, 37.6%, 15.2%, and 15.2% were on TOU-C (the default rate, 4-9 pm peak), TOU-D (5-8 pm peak), and EV2A,respectively. Another 10.7% were on legacy TOU rates, and 19.8% were still on a flat rate (E1).
On the non-event days when PG&E loads were highest, the thermostats reduced demand by 0.24	The load impacts vary by hour, with larger results in the first hour and decreasing demand reduction in later hours. The device demand reduction was limited to four hours despite the five-hour peak. The thermostats did not deliver demand reduction for the 8-9 pm hour.

Key Finding	Additional Detail
kW per site, on average, over the control hours	Because thermostat demand reduction decay with longer durations, the demand reduction for net load peak hours (7-9 pm) was substantially smaller than for the 4-7 pm period.
The algorithms automated the demand response around the correct peak hours	Most participants were on rates with a 4-9 peak. For those sites, the data shows pre-cooling from 3-4 pm and snapback after 9 pm. However, the TOU-D rate had a shorter 5-8 pm peak. For TOU-D, the data shows re-cooling from 4-5 pm and snapback after 8 pm.
Sites with daily TOU automation delivered dispatchable, event-based response over and above the daily response enabled by the thermostats	On September 7, one of the highest PG&E load days with a 5-9 pm, the thermostats delivered an incremental 0.42 kW over the DR event window, with the largest impacts, 0.75 kW per site, occurring in the first event hour. When added to the daily TOU response on high load days, the resources deliver approximately 0.66 kW over a four-hour window (0.24 from daily response plus and 0.42 of incremental event-based response.
Sites without daily automation deliver similar total demand reduction but bigger dispatchable reduction	On September 7, sites that delivered reduction only on DR event days reduced demand by 0.68 kW per site over the 5-9 pm event. The reduction is comparable to the 0.66 kW delivered by sites with daily TOU automation. As described earlier, the demand reduction from sites with daily TOU automation is made up of the daily reduction (0.24) and the incremental event day reduction (0.42).
The demand reduction is largest when temperatures are hottest, but the magnitude of the reduction decays across the event period	Nearly 90% of the variation in dispatchable demand reduction is explained by weather, the number of hours into the event, and the hour of the day. The biggest driver is the number of hours into the event. No matter the weather conditions or the event start time, we observed decay in the reduction over the event duration. The second-largest driver is the weather. The thermostats deliver larger demand reduction when temperatures are hotter.
Multiple devices at the site do not lead to double the value.	Sites with two devices delivered about 1.25x the reduction of sites with a single device. Thus, some caution is needed in enrolling sites with multiple devices.
Sites in the San Francisco-Oakland, Peninsula, and North Bay areas deliver small demand reduction	PG&E should concentrate its targeting and enrollment efforts in the Central Valley, the Bay Area Inland area surrounding the I-680 corridor, areas of the South Bay, and the Sierras. However, we also recognize that PG&E is working directly with the thermostat manufacturers and does not control all aspects of the recruitment efforts.

INTRODUCTION

This report presents the results of a 2021 study on using smart thermostats to automate daily TOU load shifting. The study provided incentives to residential customers who allowed PG&E to reduce or shift the use of electricity during the 4–9 pm peak hours by communicating with WiFi-enabled smart thermostats. The study included three types of connected thermostats – Nest, Ecobee, and Emerson and sought to understand the magnitude of dispatchable (event-based) and daily (scheduled) peak demand reduction these devices can deliver.

The study was conducted in the context of a significant energy transformation in California driven by several factors:

- The penetration of renewable resources is leading to a transformation in grid planning and operations, including:
  - ✓ A shift in the focus of planning and operations from gross to net loads – actual system demand minus intermittent renewable resources;
  - ✓ Changes in the timing of when system net loads peak;
  - ✓ Increased need for fast response resources to follow net loads and counterbalance variability in solar and wind resources;
  - ✓ Over-generation during the middle of the day, particularly on weekends in spring and fall months.
- PG&E began defaulting over three million residential customers to time-of-use (TOU) rates starting April 2021. Thus, it has become important for PG&E to understand how smart technologies with automatic "set it and forget" features can help customers succeed on these rates.
- Connected devices with the ability to schedule or shift loads are becoming more common, and their penetration in the marketplace is growing—however, each vendor and end-use requirement integration to communicate with the devices.
- As part of de-carbonization efforts, California is encouraging beneficial electrification that shifts energy consumption from fossil-based fuels to electricity generated using clean resources for vehicle, space heating, and water heating. As a result, the overall electric loads are expected to change.

TECHNOLOGY DESCRIPTION

This study, conducted under PG&E's DR Emerging Technologies Program, recruited residential customers who had already installed a smart thermostat to control central air conditioning (AC), single-stage heat pump, or multi-stage heat-pump cooling units. PG&E has contracted with a vendor called Uplight to provide recruitment services, support program participants, and manage a demand response management system (DRMS) platform to dispatch the smart thermostats.

Three distinct thermostat brands were included in the study: Nest, Ecobee, and Emerson. All the devices are internet-connected and record thermostat run time and temperature set points. They also can receive remote signals to adjust the thermostat operations. While all the thermostats delivered demand reduction, there were nuanced differences in each thermostat's recruitment, functionality and dispatch strategy, as summarized in Table 3. Most notably, both Ecobee and Emerson devices allowed customers to automate daily response to TOU rates and deliver event-based reduction. The Ecobee devices allowed customers to identify the importance of savings and comfort. Emerson devices take a similar approach but develop a thermal model for each premise and rely on a synthetic price signal.

Table 5: Smart Thermostats Brands Included in Study

		Marketing and enrollments	Functions	Event day Strategy
Nest		▪ Marketing: email and in-app notices ▪ Enrollment: web-based Nest site	▪ Event response	▪ Pre-cooling 2 hours – 3F ▪ Event: + 3F
Ecobee		▪ Marketing: email and in-app notices ▪ Enrollment: mobile app enrollment	▪ Event response ▪ Daily TOU response	▪ Pre-cooling: based on customers energy savings preferences ▪ Event: based on customers energy savings preferences
Emerson		▪ Marketing: email and in-app notices ▪ Enrollment: Uplight owned web-based site	▪ Event response ▪ Daily TOU response	▪ Proprietary optimization based on the premise's thermal model, occupant comfort bands, and a synthetic DR price signal.

Customers who opted for TOU thermostat automation self-identified their rate (sometimes incorrectly). During the study, PG&E was still rolling out default TOU across its service territory. Figure 1 shows the geographic rollout of default TOU, which started with the Bay Area and coastal areas. Default TOU did not roll out to the hotter parts of the service territory until February and March of 2022. As a result, many of the participants who enrolled in TOU thermostat automation were either in the Bay Area or had opted into elective TOU rates such as electric vehicle rates (EV2-A).

Figure 1: PG&E Default TOU Rollout Schedule

November 4, 2020 version
*Not shown on map

TRANSITION GROUP[1]	COMMUNITIES	COMMUNITY CHOICE AGGREGATOR	TOTAL PER WAVE[2]
October 2020*	Employees/Retirees of PG&E + 100 NEM Employees	All	15,000[3]
November 2020*	NEM Employees		100
Dec 2020 – Mar 2021*	Pause		0
April 2021	Sonoma, Mendocino	Sonoma Clean Power (SCP)	140,000
May 2021	Alameda	East Bay Community Energy (EBCE)	400,000
June 2021	North Coast (Humboldt, Trinity, Siskiyou)	Redwood Coast Energy Authority (RCEA)	450,000
	Santa Clara	Silicon Valley Clean Energy (SVCE) San Jose Clean Energy (SJCE)	
July 2021	San Francisco	CleanPowerSF (CPSF)	260,000
August 2021*	NEM Only	All	10,000
September 2021	San Mateo	Peninsula Clean Energy (PCE)	200,000
October 2021	Central Coast (Monterey, Santa Cruz, San Luis Obispo, Santa Barbara, San Benito)	Central Coast Community Energy (3CE) King City Community Power (KCCP)	260,000
November 2021	NEM Only	All	10,000
December 2021*	Customers with More Than 10 Accounts	All	55,000
January 2022*	NEM Only	All	10,000
February 2022	**Sacramento Valley** (Placer, El Dorado, Yolo, Butte, Nevada, Calaveras, Lake, Amador, Sutter, Yuba, Glenn, Colusa, Sacramento, Sierra, Alpine)	Pioneer Community Energy (PIO)	380,000
	Central Valley (Fresno, San Joaquin, Kern, Tuolumne, Shasta, Madera, Merced, Tehama, Plumas, Stanislaus, Mariposa, Kings, Tulare, Lassen)	Valley Clean Energy (VCE)	
March 2022	Contra Costa, Solano, Marin, Napa	MCE	410,000

[1] Customer counts are approximate. NEM customers transition on their true-up date from April 2021 to March 2022, so each wave during that period would have an additional ~10,000 NEM customers. Schedule subject to change.
[2] Total Per Wave customers rounded out to the nearest ten-thousandth.
[3] Of the 15,000 customers in the October 2020 transition group, ~7,500 customers are deferred to a future wave due to wildfires.

KEY RESEARCH QUESTIONS

For clarity, we separate the research questions into three main categories:

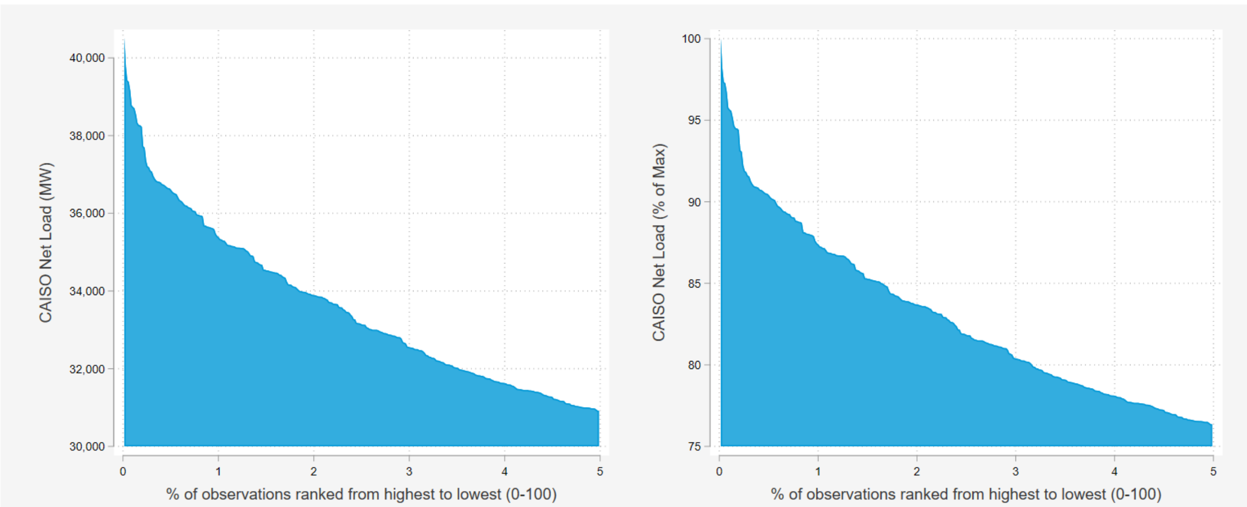
Category	Research Questions
Program Participation	▪ How do enrollment rates vary by thermostat brand and by recruitment mechanism?
	▪ What are TOU optimization enrollment rates? Do they vary by vendor?
	▪ What are the characteristics of program participants?
Event-based demand reduction	▪ What are the event (dispatchable) load impacts for each event called - overall and incremental to the TOU response?
	▪ How do the dispatchable event load impacts vary by: ✓ By manufacturer? ✓ TOU auto-programming? ✓ By geography? ✓ By temperature conditions? ✓ Low-income status? ✓ Number of devices at the site?
	▪ Do savings persist across the event hours?

Category	Research Questions
	▪ Are the load impacts estimated using AMI data similar to the load impacts estimated using AC runtime data?
Automated Daily TOU Response	▪ What is the TOU device response incremental to the behavioral price response?
	▪ Do the load impacts vary by: ✓ By manufacturer? ✓ By geography? ✓ By temperature conditions? ✓ Low-income status? ✓ Number of devices at the site?
	▪ Do TOU demand reduction persist across the peak hours?

SYSTEM PEAKING CONDITIONS AND PARTICIPANT LOADS

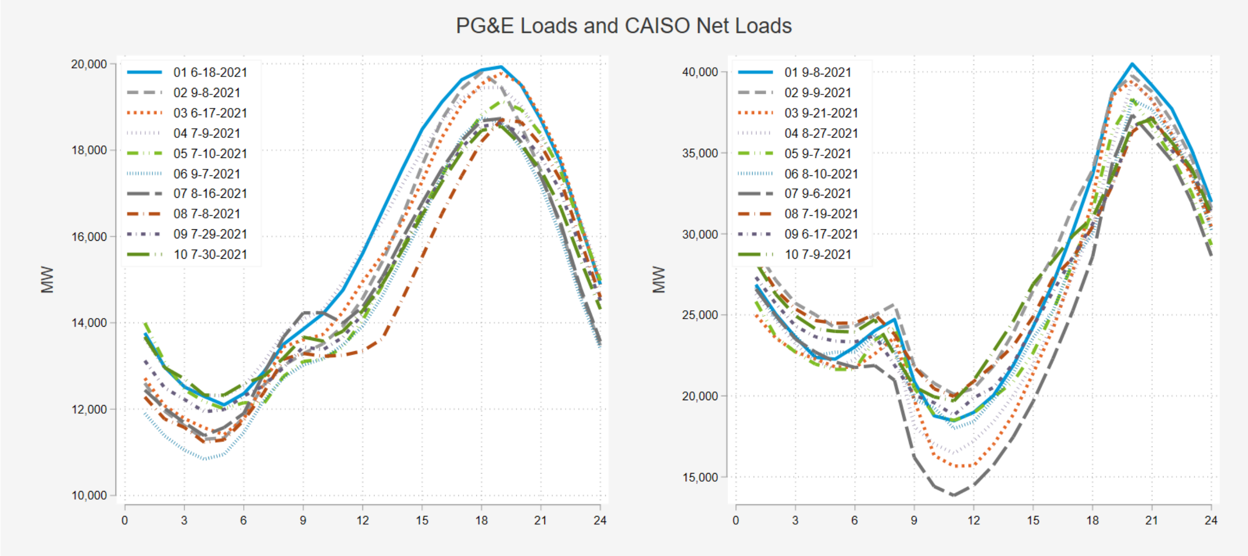
PG&E peak loads remain highly concentrated in a limited number of hours, as shown in Figure 2. The plot shows the load duration curve – a metric of peakiness – which plots demand ranking the highest load hours first. To top 5,000 MW (12%) are concentrated in less than 1% of hours. System load rarely exceeded 30,000 MW during the 2021 summer. The 2021 system peak, which occurred on September 8, was 40,495 MW. A demand response event was dispatched from 6:00 pm through 9:00 pm on the peak day. Figure 3 compares the ten days with the highest PG&E loads to the ten days with the highest CAISO net loads.

Figure 2: 2021 System Load Duration Curves



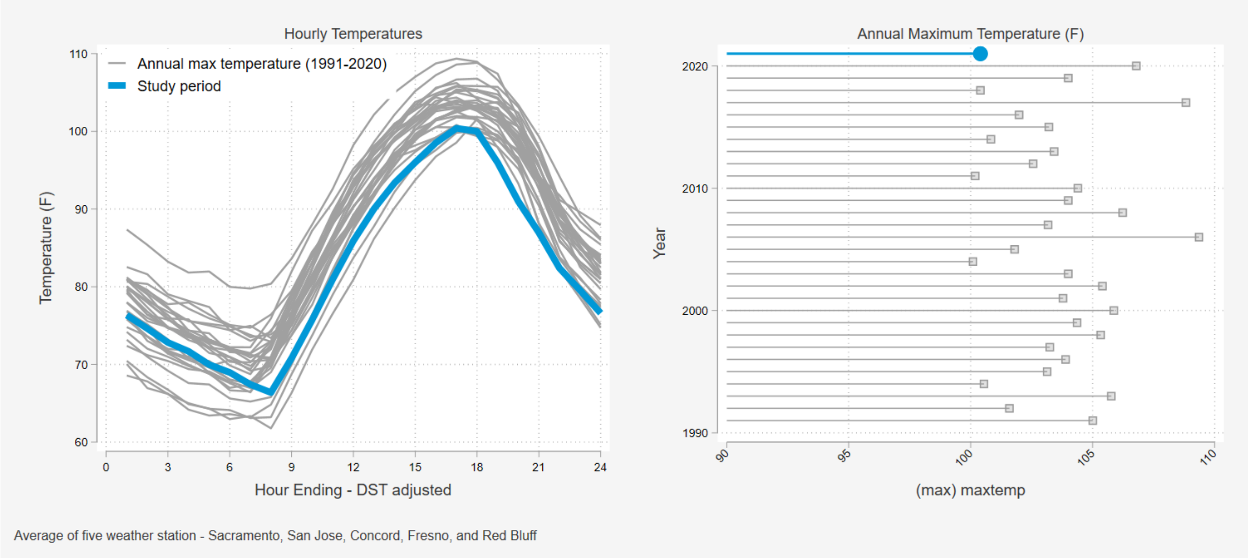
2019-2021 CAISO Net loads from OASIS

Figure 3: Top Ten System Load Days, 2021



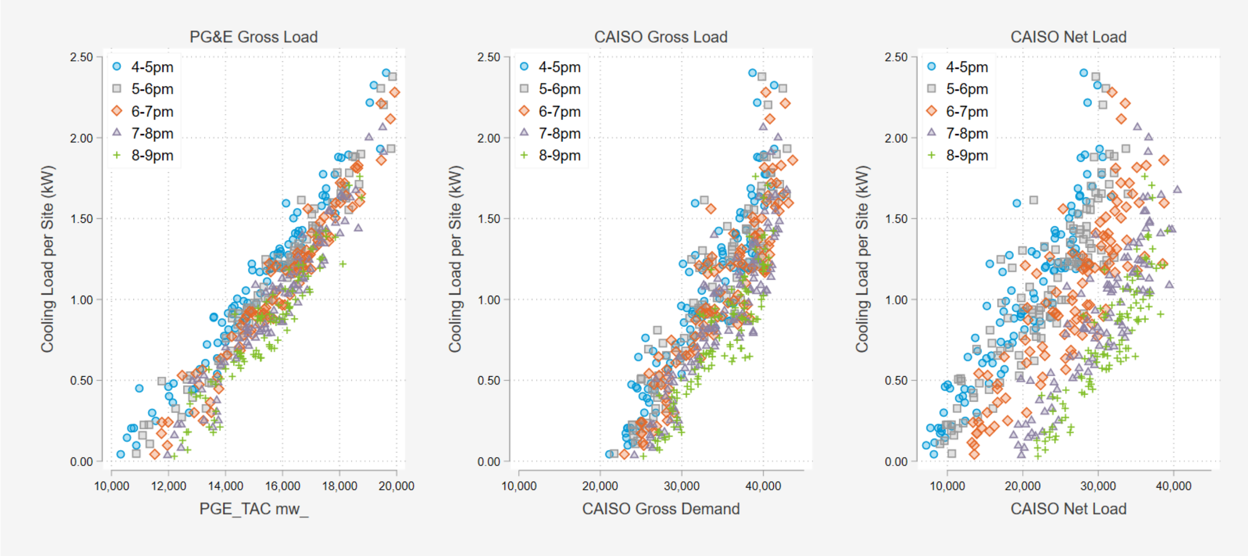
The weather over the 2021 study period was considerably milder than in historical years. Figure 4 compares the annual maximum temperature days from 1991-2020 to the conditions over the 2021 study period. Since the resource is weather-sensitive, the reduction observed in 2021 were lower than they would be under hotter conditions.

Figure 4: Comparison of Study Period Temperature Conditions to Historical Years



There is a strong correlation between system loads and cooling loads. Figure 10 shows the relationship for all peak hours (4-9 pm). In laymen's terms, cooling loads per site are larger when system loads are higher. The relationship is weaker for CAISO Net Loads (far right pane in Figure 5). Specifically, the air conditioner loads are larger during the early hours of the 4–9 pm peak period and lower in later hours. Net loads tend to peak between 6- 9 pm.

Figure 5: Participant Cooling Loads are Correlated with System Loads



PARTICIPANT CHARACTERISTICS AND ENROLLMENT

By September 30, 2021, PG&E had 11,303 active participants with 13,713 thermostats. Figure 6 shows the number of devices enrolled in the study over time by device brand. On average, participants had cooling loads of nearly 2.5 kW of cooling load and whole building loads that exceed 3.0 kW on the hottest days. However, the overall cooling loads vary by time of day, as shown in Figure 7, and begin to decrease in the evening hours as temperatures start to cool and air conditioners do not have to run as heavily.

Figure 6: Participating Devices Over Time by Brand

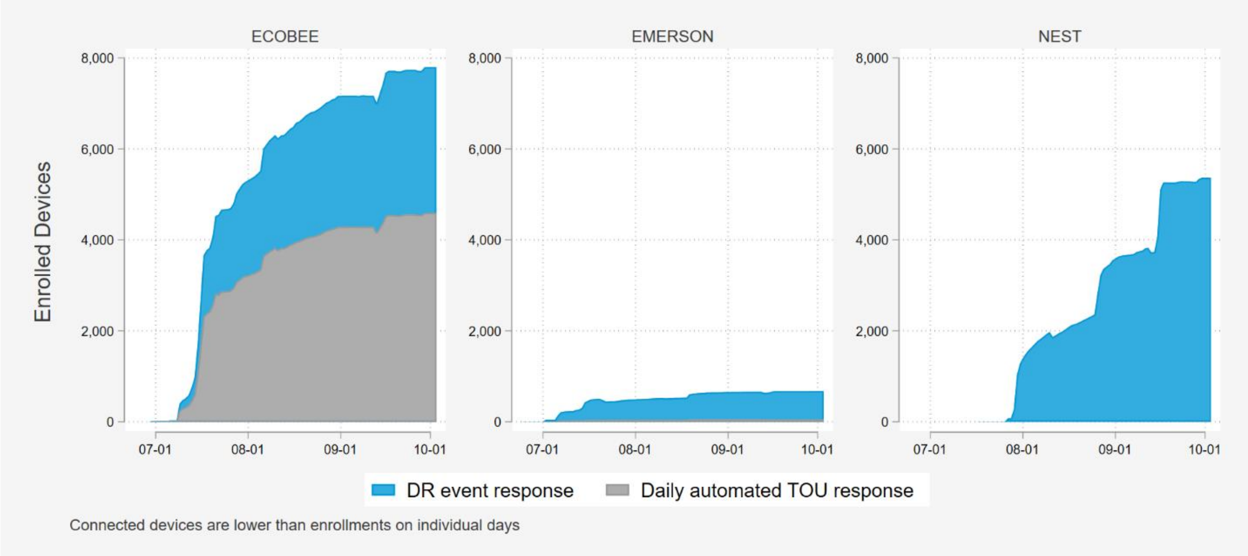


Figure 7: Weather Sensitivity and Cooling Loads Per Site

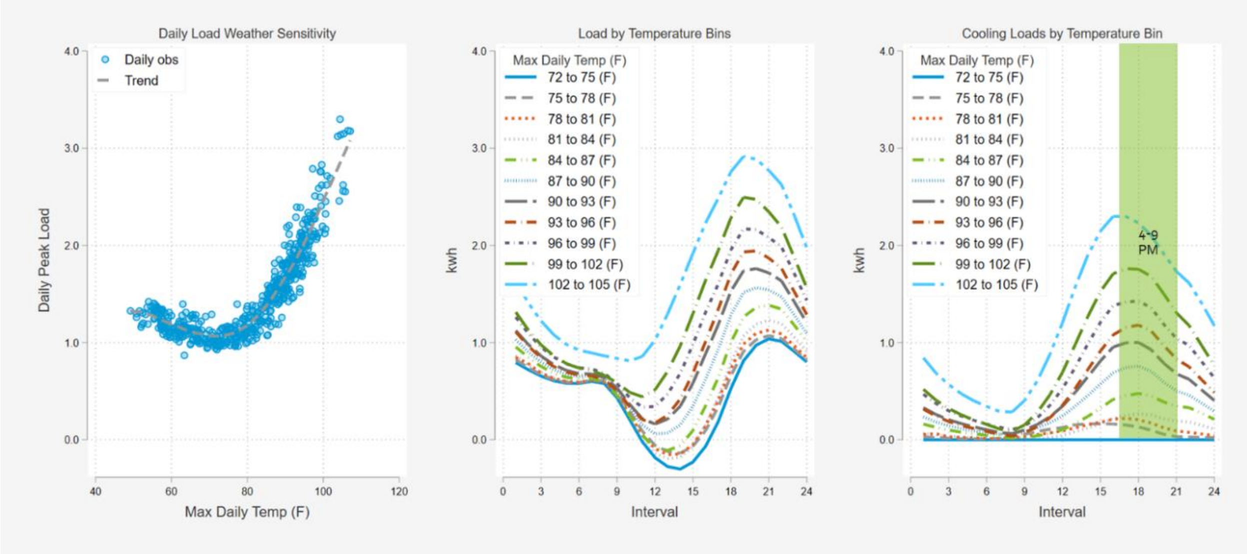


Table 6 shows the distribution of participants by geographic location, brand, and daily TOU automation. Figure 8 shows that the geographic distribution of devices was similar across each brand. Figure 9 shows additional comparisons by brand. Some key highlights include:

- A total of 13,713 thermostats were enrolled. The average site had 1.21 thermostats.
- Nest thermostats did not participate in the TOU response program.
- 57.9% of participants with ecobee devices elected daily TOU automation.
- Participants had a higher penetration of rooftop solar than the PG&E population.

Table 6: Number of Participants on September 30, 2021

	ECOBEE		EMERSON		NEST		ALL	
Geographic Area	No TOU automation	Daily TOU Automation	No TOU automation	Daily TOU Automation	No TOU automation	Daily TOU Automation	No TOU automation	Daily TOU Automation
Bay Area Inland	480	684	79	5	861	0	1,420	689
Central Valley Middle	364	476	83	4	501	0	948	480
Central Valley North	65	73	13	0	90	0	168	73
Central Valley South	558	526	86	1	467	0	1,111	527
North Bay	147	158	45	5	221	0	413	163
Other	26	31	13	1	26	0	65	32
Peninsula	78	138	18	2	250	0	346	140
San Francisco – Oakland	104	164	23	4	202	0	329	168
Sierras	199	261	60	2	187	0	446	263
South Bay	583	1,073	116	20	1,546	0	2,245	1,093
South Coast	53	64	10	1	56	0	119	65
Total	2,657	3,648	546	45	4,407	0	7,610	3,693
Super Total	6,305		591		4,407		11,303	

Enrolled Sites on September 30, 2021

Figure 8: Geographic distribution of customers

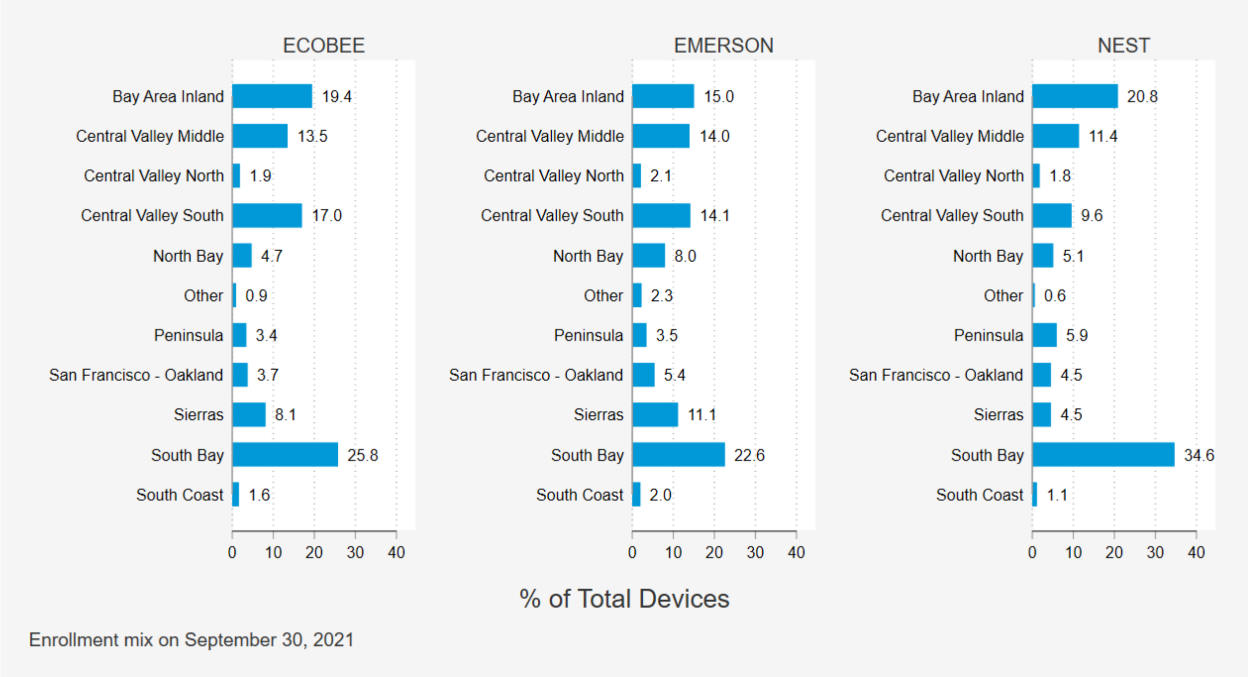
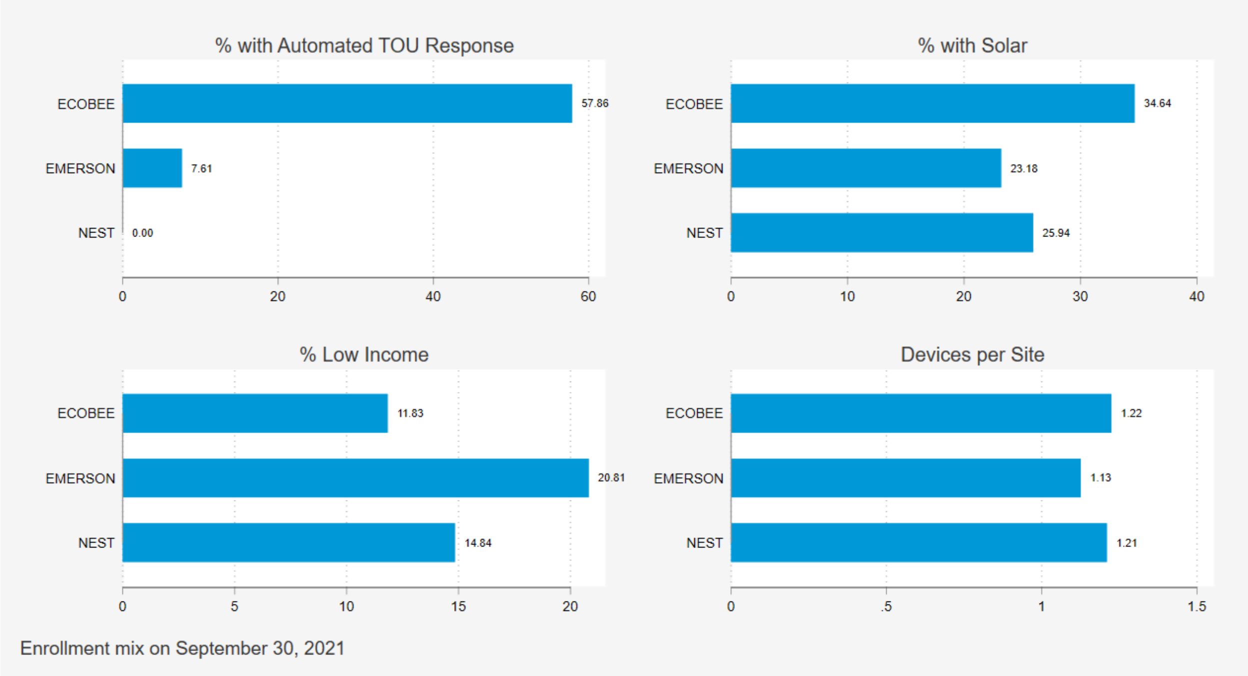


Figure 9: Differences by Brand



2021 EVENT CONDITIONS

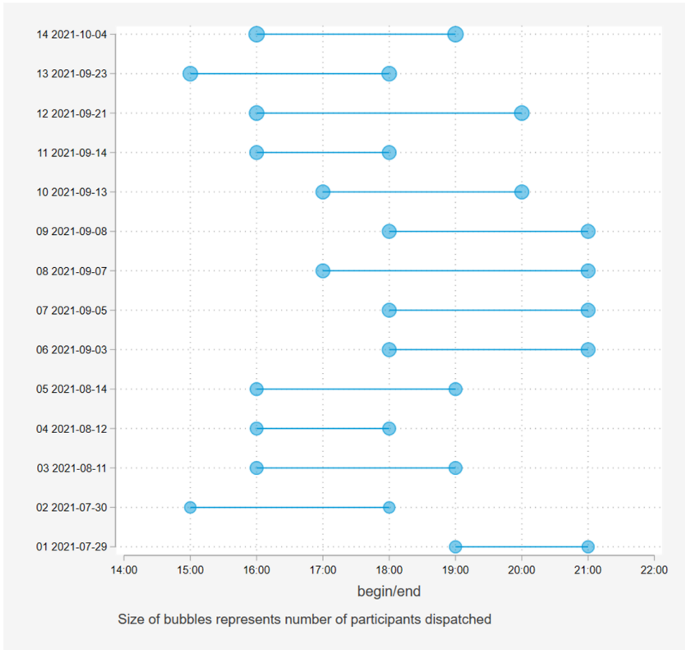
A key goal of the study was to learn as much as possible as soon as possible about performance during different event conditions – defined by weather, hours of dispatch, event duration, and day type (weekdays vs. weekends). DSA and PG&E developed a systematic operations plan for DR events to achieve this goal over the course of half a summer. The objective was to collect a body of evidence over a short period to understand how and why load reduction performance varied.

Figure 10 visualizes the variation in event times, day type, and weather conditions. The figure also includes weather, market prices, and system loads for context. PG&E intentionally dispatched the thermostat under a wide range of conditions (including cooler days) for research purposes. The need for resources was highest on September 7th and 8th, which had the highest PG&E loads and some of the highest CAISO net loads in 2021.

A total of 13 events were called over roughly two months, in addition to an early test to ensure operations and communications worked. The events vary in start time, duration, and temperature. They include two events when all resources were dispatched (July 29 and October 4) and two events called on weekends (August 14 and September 5). Only ecobee devices were available for the first event.

Figure 10: Events and System Conditions

	Daily Peak...				
Event Date	CAISO Net load	PG&E Demand	Market price (PG&E DLAP)	DR-5 Max Temperature	Participant temperature (weighted)
10/4/2021	31,829	14,896	$137.91	89.6	88.4
9/21/2021	39,423	16,893	$187.49	94.0	93.9
9/14/2021	34,699	17,215	$123.62	95.4	90.5
9/13/2021	36,055	17,295	$152.21	94.8	91.5
9/8/2021	40,495	19,803	$285.31	101.4	97.5
9/7/2021	38,331	18,748	$164.41	100.6	96.9
9/5/2021	36,242	15,614	$124.36	97.0	95.1
9/3/2021	32,084	14,639	$86.54	87.8	85.7
8/14/2021	32,348	16,991	$95.28	96.8	98.3
8/12/2021	35,659	17,753	$167.68	95.6	95
8/11/2021	36,074	18,335	$220.00	98.2	98.3
7/30/2021	36,558	18,556	$311.87	99.0	96
7/29/2021	36,652	18,628	$402.73	98.8	94.7



METHODOLOGY

The primary challenge of impact evaluation is the need to accurately detect changes in energy consumption while systematically eliminating plausible alternative explanations for those changes, including random chance. Did the dispatch of demand response resources cause a decrease in hourly demand? Or can the differences be explained by other factors? To estimate demand reduction and daily load shifting, it is necessary to estimate what demand patterns would have been in the absence of the intervention – this is called the counterfactual or reference load.

Table 7 summarizes the methodology. The remainder of this section provides additional detail about the methodology.

Table 7: Summary of Methodology

COMPONENT	Event-based DR	Daily TOU Automation
Population analyzed	Full population of enrolled sites. It varied by event date but reached over 11,300 sites and over 13,700 devices by end of September	Full population of ecobee devices with TOU automation, which included over 3,600 sites by the end of September
Data source	PG&E AMI data	PG&E AMI data
Operations	Based on operations plan intentionally designed to introduce variation in weather, event start times, duration of event, and weekend/weekday conditions	Daily. Once a site enrolled on daily automation of TOU response via thermostats, the algorithms were in operation each day.
Control group	Randomly assigned. Sites were re-randomized for each event/	Matched control group using propensity score matching. The control candidates were selected from a pool of ecobee participants without TOU automation, matched to mirror TOU automation participant characteristics. More detail about the matched control group can be found in Appendix C.
Analysis technique	Panel regression with differences-in-differences. Same hour patterns on similar days were used to net out pre-existing differences between control and treatment customers.	Manual difference-in-differences for same hour on similar days. Estimated the impacts for all hours of each day post-enrollment and for specific day types (e.g., high PG&E load days). Event days were excluded from the analysis to avoid double-counting.

DEMAND REPONSE EVENT OPERATIONS PLAN

Because the program is new the goal was to learn as much as possible as soon as possible to inform operations and decisions about how to scale to a program. To achieve this goal over the course of half a summer, DSA and PG&E produced a systematic operations plan for DR events. If left to weather and market operations alone, it can take multiple years to capture sufficient variability in event conditions to adequately model performance under a range of conditions.

The operations plan intentionally varied event start times and event durations. It intentionally included a wide range of weather conditions, including cooler than peaking conditions, as well as weekday and weekend dispatch. The objective was to collect a body of evidence to understand how load reduction performance varied as function of the above factors.

The table below details the operations plan and maps it to the events called. The operations plan was grounded on a base event – the most common expected dispatch. Each subsequent event varies one element at a time. In addition, the plan incorporated full resources dispatch events for testing purposes and in the case of CAISO system emergencies.

Table 8: Event Operations Plan

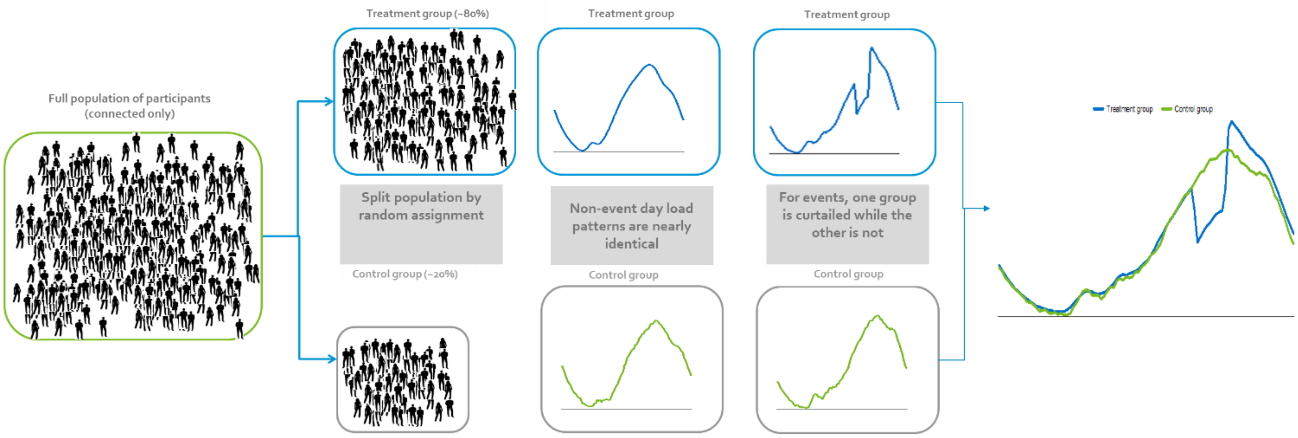
No.	Date	Test Element	Temperature	Event Start	Event Duration (hours)	Weekday or weekend
0	7/22/2021	Operational test	Hot	4:00 PM	3	Weekday
1	7/29/2021	Full dispatch event	Very hot	7:00 PM	2	Weekday
2	7/30/2021	Early event start	Very hot	3:00 PM	3	Weekday
3	8/11/2021	Base event (3 hour event at 4:00 pm)	Very hot	4:00 PM	3	Weekday
4	8/12/2021	Short event and temperature	Hot	4:00 PM	2	Weekday
5	8/14/2021	Weekend event	Very hot	4:00 PM	3	Weekend
6	9/3/2021	Late event start	Very hot	6:00 PM	3	Weekday
7	9/5/2021	Late event start and weekend	Very hot	6:00 PM	3	Weekend
8	9/7/2021	Longer duration	Very hot	5:00 PM	4	Weekday
9	9/8/2021	Late event start	Very hot	6:00 PM	3	Weekday
10	9/13/2021	Late event start and temperature	Hot	5:00 PM	3	Weekday
11	9/14/2021	Shorter event duration and temperature	Hot	4:00 PM	2	Weekday
12	9/21/2021	Long event duration and temperature	Hot	4:00 PM	4	Weekday
13	9/23/2021	Early event start and temperature	Hot	3:00 PM	3	Weekday
14	10/4/2021	Full dispatch event	Hot	4:00 PM	3	Weekday

DEMAND RESPONSE EVENTS RANDOMIZED CONTROL TRIAL

A key factor for demand response resources is the ability to dispatch the resource. The primary intervention, demand response dispatch, is introduced on some days and not on others, making it possible to observe energy use patterns with and without demand reduction. This, in turn, enables us to assess whether the outcome – electricity use – rises or falls with the presence or absence of demand response dispatch instructions.

The primary evaluation method was a randomized control trial analyzed using a difference-in-differences panel regression. Figure 11 below summarizes the core concept of the randomized control. For each event day, participants with connected devices are randomly assigned to be dispatched or serve as a control. Because the sites are randomly assigned, they are equivalent in all aspects, but some differences can occur due to sampling. On the event day, all sites except those assigned to serve as a control group are dispatched. The control group is used to establish the baseline of what loads would have been if sites hadn't been dispatched. The control sites are in the same geographic locations, experience the same weather, and have same characteristics – the only difference is that one group was dispatched while another group was not.

Figure 11: Randomized Control Trial Conceptual Example



With large enough sample sizes, the approach produces very precise load impacts estimates. However, differences can arise between the treatment and control groups due to the random sampling inherent to random assignment. Thus, as part of the analysis we compared the treatment and control group during hot non-event days and netted out the pre-existing differences – a technique known as difference-in-differences. The approach simply reduces noise so the signal – the load impact – can be better detected.

Because of the rapid growth over the course of the a few month, the number of sites that were randomly assigned to serve as a control group varied by event day. Table 9 summarizes the logic underlying the control group size for each event and brand.

Table 9: DR Control Group Size Logic

Number of Sites	Control Group size
101-600	50%
601-1,000	40%
1,001-2,500	30%
2,501-4,000	25%
>4,000	1,000

DAILY TOU THERMOSTAT AUTOMATION RESULTS

This section focuses on daily automated response to TOU rates by the thermostats. The overall demand reduction for these sites has two distinct components – the daily automated TOU response, and the event-based load reduction over and above to the daily response. In both cases, the demand reduction is due to the thermostat algorithms and incremental to any behavioral response to TOU rates. Both the participants and the matched control group were on similar rates. This section focuses solely on the daily TOU response. The incremental event-based demand reduction is presented in the section titled *Incremental Event Impacts for Sites with Time Of Use Automation*.

Roughly 57.9% of ecobee participants opted to automate TOU response on a daily basis via their thermostat. Each customer decided on their preference between comfort and savings, and each customer self-identified their rate.

DSA matched customers who enrolled in TOU automation to customers who declined daily TOU automation using propensity score matching. Both the control group and TOU automation group had a smart thermostat, agreed to participate in the study, had similar load patterns and characteristics before the TOU automation, and were on the same rate. The load impacts were calculated using difference-in-differences. The analysis was implemented at different levels of time granularity (e.g., by date and hour, by date and peak period, by hour) and for different segments. The analysis did not include event days since both sites with and without TOU automation (the control group) were dispatched.

TOU HOURLY AND DAILY ENERGY SAVINGS

Figure 12 shows the hourly loads for the participants and the matched control group. Both groups had similar load patterns before enrolling in the study. However, once the TOU automation algorithm went into effect, the TOU automation group reduced demand from 4-8 pm each day. No reduction was observed for 8-9pm. The load data for the sites shows pre-cooling before the peak period and snapback once the peak period concludes. Figure 13 shows the daily peak period reduction due to the thermostat TOU response algorithm.

Figure 12: Hourly Loads With and Without TOU automation (Difference-in-Differences)

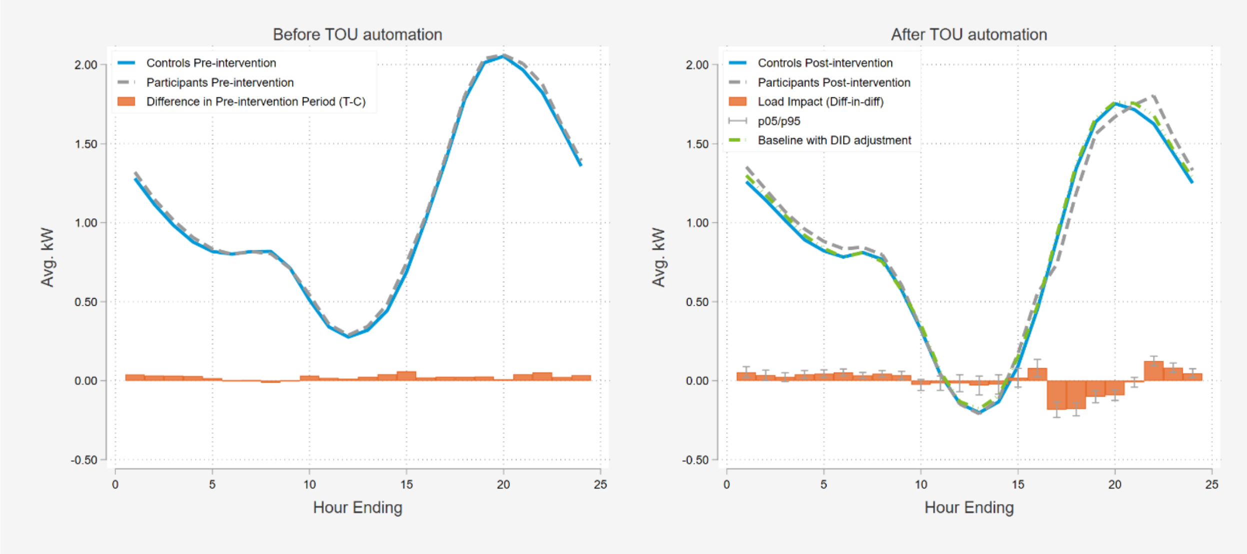
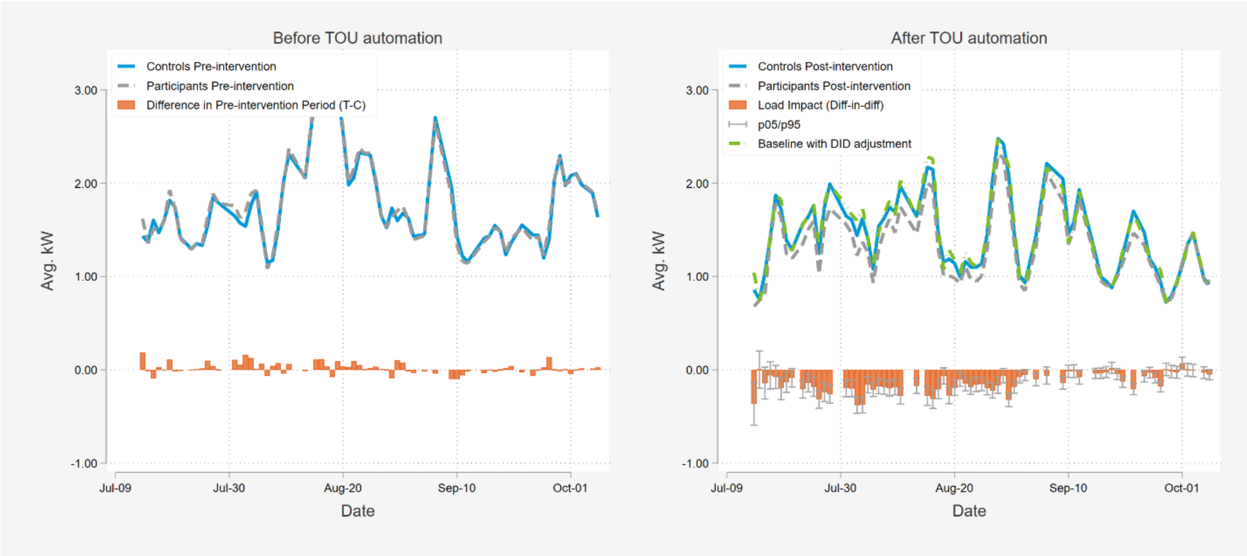


Figure 13: Daily Peak Average Demand Reduction Due to TOU Automation (4-9 pm)



We also estimated the load impacts for each individual date and hour. While the individual hour results are noisier, they provide useful insights when displayed as a heat map, as shown in Figure 14. The demand reduction is concentrated in the 4–9 pm period, largest in earlier hours of the peak period, and coincides with hotter temperatures. From a planning and resource adequacy perspective, however, the focus in on peak days.

Table 10 shows the hourly load impacts for peak days and the average day of each month. We include the demand reduction when the PG&E territory peaks and for when CAISO gross and net loads peak. The electronic tables provide more detail, including participant counts, load impacts for each hour, and confidence bands. Figure 15 shows an example of the tables, using the impacts on the Top 20 PG&E system load days as an example.

Figure 14: Heat Map of Demand Reduction Due to Daily TOU Automated Response

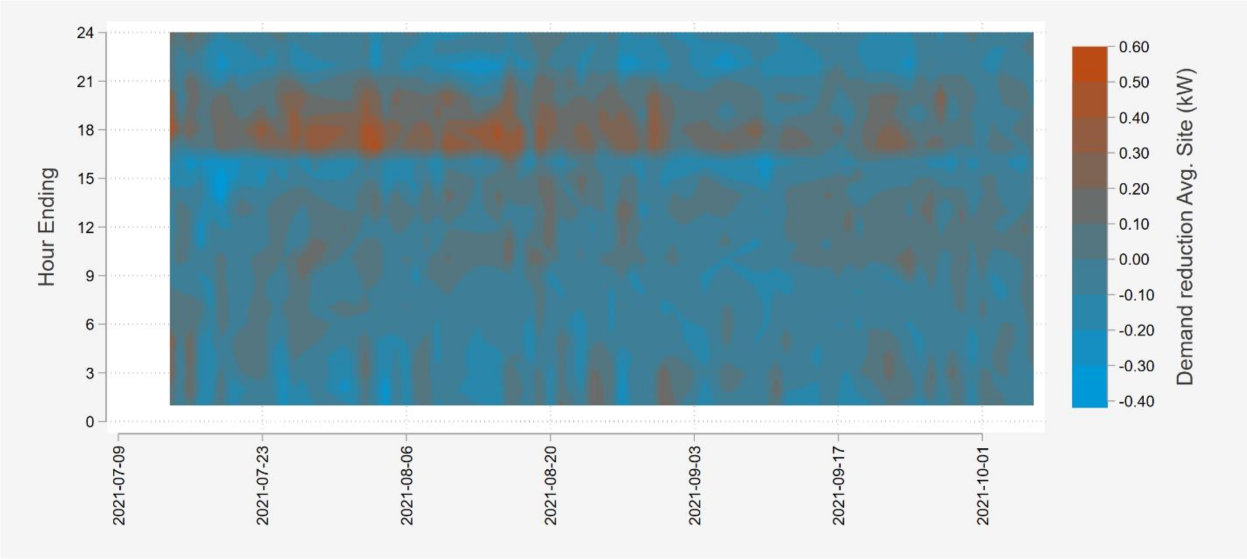


Table 10: Daily TOU Automation Peak Period Load Impacts by Day Type

System	Day Type	Accounts (Average)	Max Temp (Participant weighted)	4:00-5:00 PM	5:00-6:00 PM	6:00-7:00 PM	7:00-8:00 PM	8:00-9:00 PM	Average 4-9 PM
ALL	AVERAGE DAY JULY	1,712	90.2	0.25	0.30	0.21	0.16	-0.05	0.17
	AVERAGE DAY AUGUST	2,353	87.9	0.26	0.27	0.18	0.13	0.04	0.18
	AVERAGE DAY SEPTEMBER	2,530	83.7	0.09	0.09	0.01	0.04	-0.07	0.03
PG&E	PEAK DAY JULY	132	97.6	0.06	0.36	0.47	0.21	-0.06	0.21
	PEAK DAY AUGUST	2,278	94.0	0.37	0.29	0.23	0.21	0.05	0.23
	PEAK DAY SEPTEMBER	2,269	93.4	0.17	0.17	0.01	0.04	-0.01	0.08
	TOP 10 DAYS	2,062	91.6	0.38	0.26	0.33	0.27	-0.05	0.24
	TOP 20 DAYS	2,387	93.0	0.32	0.28	0.17	0.16	0.00	0.19
CAISO	PEAK DAY JULY	1,174	90.0	0.17	0.18	0.13	0.11	-0.02	0.11
	PEAK DAY AUGUST	2,293	93.3	0.41	0.32	0.24	0.22	0.00	0.24
	PEAK DAY SEPTEMBER	2,265	87.6	0.08	0.20	0.01	0.02	0.02	0.07
	TOP 10 DAYS	2,382	92.4	0.29	0.29	0.19	0.18	0.04	0.20
	TOP 20 DAYS	2,387	91.1	0.32	0.32	0.19	0.17	-0.03	0.19
CAISO Net Loads	PEAK DAY JULY	1,471	92.6	0.31	0.31	0.19	0.18	-0.29	0.14
	PEAK DAY AUGUST	2,293	92.8	0.37	0.30	0.23	0.21	0.03	0.23
	PEAK DAY SEPTEMBER	2,269	93.4	0.17	0.17	0.01	0.04	-0.01	0.08
	TOP 10 DAYS	2,381	93.9	0.26	0.23	0.11	0.11	0.15	0.17
	TOP 20 DAYS	2,603	91.5	0.29	0.24	0.14	0.15	0.00	0.16

Figure 15: Example of Ex-Post Tables for Daily TOU Automation

Pacific Gas and Electric

Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

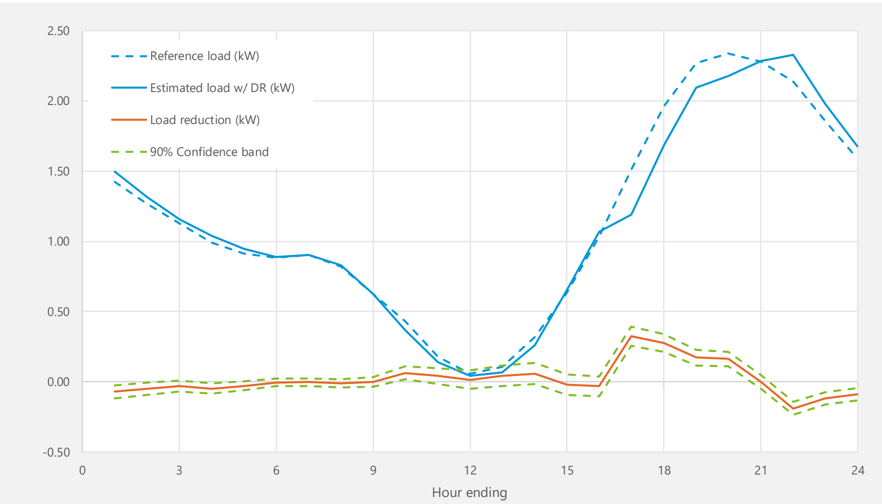
PowerSaver Rewards 2021 TOU Automation Load Impacts (Does not include incremental event-based response)

Table 1: Menu options

Program	Powersaver Rewards
Data source	AMI
Method	Difference-in-differences
Type of result	Per customer
Day Type	PG&E TOP 20 DAYS
Category	ALL
Subcategory	All

Table 2: Peak Window and Participant information

Total sites	2,387
Peak Period window temperature (F)	89.1
Max demand reduction during peak (k\	0.32
Average reduction during peak (kW)	0.19
Average % load reduction	9.9%

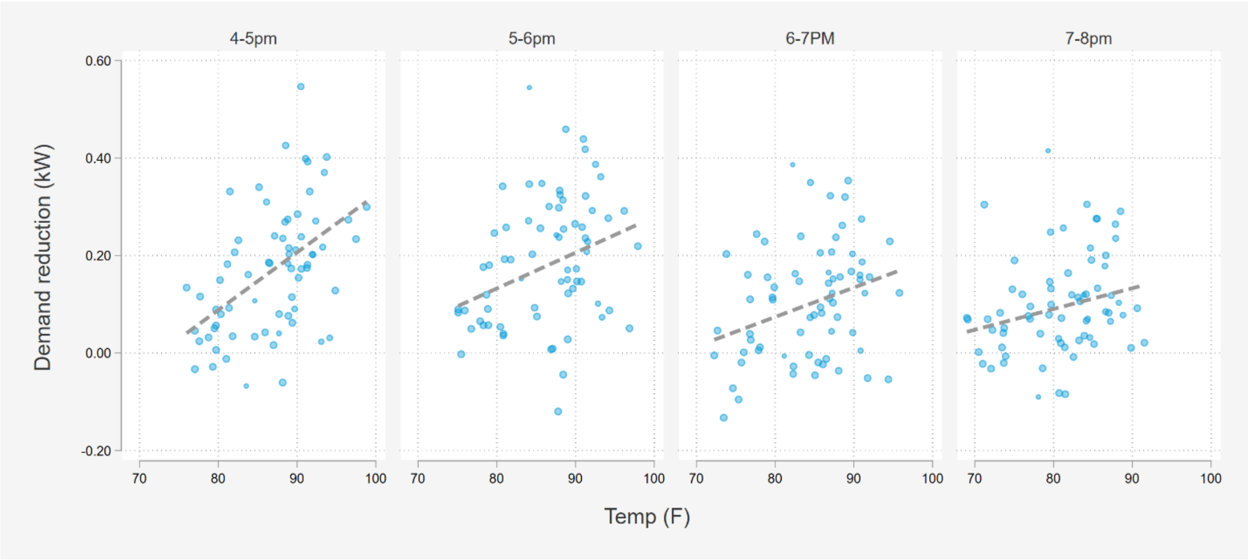


Hour ending	Reference load (kW)	Estimated load w/ DR (kW)	Load reduction (kW)	% Load reduction	Avg temp (F, site weighted)	90% Confidence Interval 5th	90% Confidence Interval 95th	Std. error	T-statistic
1	1.42	1.50	-0.07	-5.0%	69.9	-0.12	-0.02	0.028	-2.50
2	1.27	1.32	-0.05	-3.9%	68.5	-0.09	-0.01	0.026	-1.89
3	1.13	1.16	-0.03	-2.7%	67.2	-0.07	0.01	0.024	-1.25
4	0.99	1.04	-0.05	-5.1%	66.2	-0.09	-0.01	0.022	-2.24
5	0.92	0.95	-0.03	-3.3%	65.2	-0.06	0.00	0.019	-1.61
6	0.88	0.89	0.00	-0.5%	64.5	-0.03	0.02	0.017	-0.28
7	0.90	0.90	0.00	-0.4%	63.9	-0.03	0.02	0.017	-0.21
8	0.82	0.83	-0.01	-1.4%	63.6	-0.04	0.02	0.017	-0.65
9	0.63	0.63	0.00	-0.2%	66.3	-0.03	0.03	0.021	-0.05
10	0.43	0.37	0.06	14.4%	70.5	0.02	0.11	0.028	2.22
11	0.18	0.14	0.04	22.8%	75.2	-0.01	0.10	0.034	1.21
12	0.06	0.04	0.01		79.7	-0.05	0.08	0.040	0.37
13	0.11	0.06	0.04	38.7%	83.9	-0.03	0.11	0.044	0.93
14	0.32	0.26	0.06	18.4%	87.5	-0.02	0.13	0.046	1.28
15	0.64	0.66	-0.02	-3.4%	90.5	-0.10	0.05	0.045	-0.47
16	1.03	1.07	-0.03	-3.2%	92.2	-0.11	0.04	0.044	-0.76
17	1.51	1.19	0.32	21.3%	93.0	0.25	0.39	0.042	7.65
18	1.96	1.69	0.28	14.0%	92.6	0.21	0.34	0.037	7.38
19	2.27	2.10	0.17	7.6%	90.7	0.12	0.23	0.034	5.13
20	2.34	2.18	0.16	6.9%	87.0	0.11	0.21	0.030	5.36
21	2.28	2.28	0.00	-0.1%	82.2	-0.05	0.04	0.028	-0.08
22	2.14	2.33	-0.19	-8.9%	78.0	-0.24	-0.14	0.028	-6.73
23	1.86	1.98	-0.12	-6.5%	75.2	-0.16	-0.08	0.027	-4.44
24	1.59	1.68	-0.09	-5.6%	72.9	-0.13	-0.05	0.026	-3.49
Daily	**Reference load (kWh)**	**Estimated load w/ DR (kWh)**	**Energy savings (kWh)**	**% Change**	**Avg. Daily Weighted temp (F)**	**Uncertainty adjusted impact - Percentiles 5th**	**Uncertainty adjusted impact - Percentiles 95th**	**Std. error**	**T-statistic**
Daily kWh	27.67	27.23	0.44	1.6%	76.94	0.18	0.69	0.15	2.84
Peak (4-9 PM)	2.07	1.89	0.19	9.9%	89.11	0.15	0.22	0.019	9.59

TOU AUTOMATED RESPONSE WEATHER SENSITIVITY

A key goal of the study was to quantify the relationship between demand reduction, temperature conditions, and hour-of-day. DR programs that manage air conditioning loads tend to deliver bigger demand reduction when temperatures are hotter. Figure 16 shows the relationship between temperature and demand reduction by hour-of-day. Each dot represents a day over the study period. Overall, demand reduction grows larger with hotter temperatures. However, load reduction is largest in the first hour and decay over the course of the peak period.

Figure 16: Weather Sensitivity of Demand Reduction from Daily TOU Automated Response



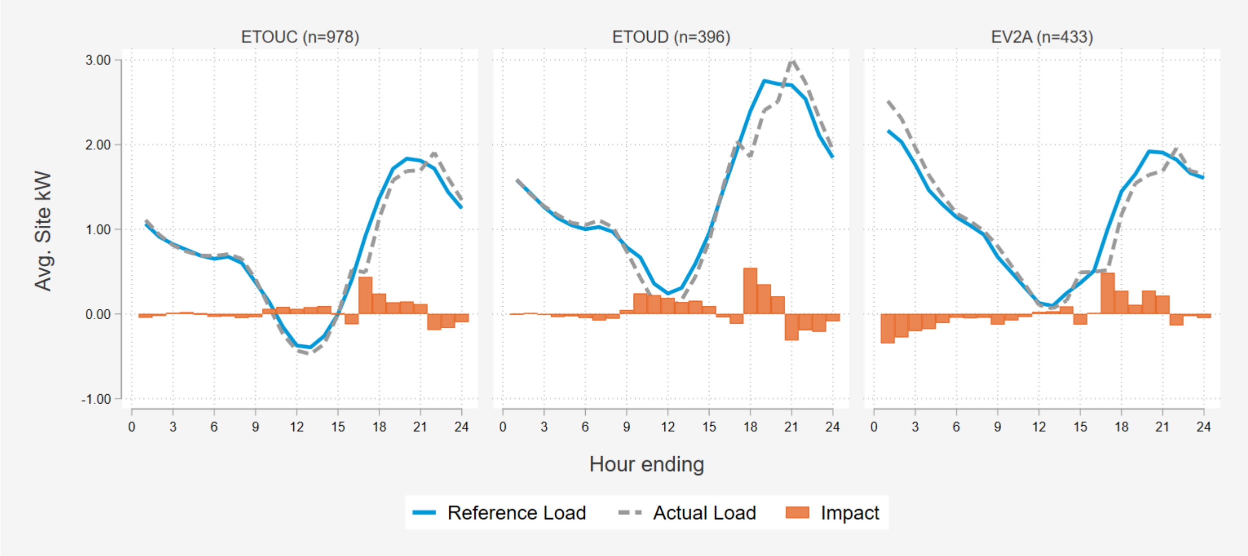
TOU AUTOMATED RESPONSE BY CUSTOMER TYPE

As a final step, we assessed how the load reductions varied by customer characteristics. Table 11 summarizes results for various segments. For the comparison, we used the results for the top 20 CAISO net loads days in the evaluation period. We caution that results are noisier when customer counts are smaller. Irrespective of the segment, the reduction in the first hour are larger and decay over the course of the peak period. The results for rates TOU-C, TOU-D, and EV-2 are also shown in Figure 17, and are of interest due to the implementation of default TOU and the growth in electric vehicles. In 2021, PG&E started defaulting customers to rate TOU-C, with a 4-9 pm peak period. However, customers could opt instead for rate TOU-D, with a 5-8 pm peak period. The results reflect that the thermostat properly automated the response for the right peak hours. Specifically, we observe reduction from 5-8 pm for TOU-D, with pre-cooling in 4-5 pm and snapback after 8 pm. Notably, customers self-identified their rate, and about 20% of sites that elected for TOU automation were not on TOU rates but on PG&E's flat rate, E1. They still delivered daily demand reduction.

Table 11: Daily TOU Automation Impact by Segment – CAISO Net Loads Top 20 Days

						Hour into event (Avg.)[1]					Event Hour Average[2]				
Category	Sub-category		% of Accounts	Event hours Avg. Temp	Max Temp (Participant weighted)	4-5 PM	5-6 PM	6-7 PM	7-8 PM	8-9 PM	Reference Load (Baseline)	Impact	std. error	t	% Impact
ALL	All	2,603	100.0%	87.3	91.5	0.29	0.24	0.14	0.15	0.00	1.91	0.16	0.01	11.79	8.6%
GEOGRAPHIC AREA	Bay Area Inland	469	18.2%	92.8	98.9	0.13	0.12	0.02	-0.01	-0.15	1.83	0.02	0.03	0.62	1.1%
	Central Valley Middle	340	13.2%	94.0	96.9	0.37	0.42	0.28	0.24	0.05	2.43	0.27	0.04	6.31	11.3%
	Central Valley North	48	1.9%	94.3	96.9	-0.05	0.18	0.26	0.24	0.06	2.44	0.14	0.11	1.31	5.8%
	Central Valley South	365	14.1%	100.6	102.4	0.27	0.21	0.10	0.13	-0.12	2.75	0.12	0.04	2.78	4.2%
	North Bay	113	4.4%	83.2	90.2	0.16	0.02	0.18	0.26	0.08	1.50	0.14	0.06	2.28	9.5%
	Peninsula	103	4.0%	74.4	79.2	0.36	0.10	0.14	0.21	0.19	1.37	0.20	0.06	3.17	14.5%
	San Francisco - Oakland	94	3.6%	72.0	75.9	0.20	0.28	0.24	0.11	0.04	0.93	0.17	0.05	3.30	18.7%
	Sierras	173	6.7%	89.2	93.1	0.70	0.56	0.17	0.34	0.14	2.52	0.38	0.07	5.64	15.1%
	South Bay	825	31.9%	79.8	84.7	0.30	0.24	0.16	0.15	0.00	1.46	0.17	0.02	8.03	11.6%
	South Coast	53	2.1%	76.5	84.5	0.25	0.19	-0.01	0.11	0.32	1.75	0.17	0.09	1.85	9.9%
LOW INCOME	NO	2,321	89.2%	86.7	91.0	0.29	0.26	0.16	0.17	0.02	1.84	0.18	0.01	12.34	9.9%
	YES	282	10.8%	92.4	95.5	0.26	0.08	0.02	-0.07	-0.18	2.45	0.02	0.04	0.54	1.0%
NUMBER OF DEVICES	1 thermostat	2,034	78.4%	86.9	91.1	0.27	0.22	0.15	0.15	0.01	1.84	0.16	0.01	10.79	8.8%
	2 thermostats	505	19.5%	88.5	92.6	0.44	0.37	0.17	0.17	-0.01	2.11	0.23	0.04	6.32	10.7%
	3 or more thermostats	55	2.1%	90.7	94.7	-0.44	-0.19	-0.32	-0.27	-0.32	2.29	-0.31	0.12	-2.54	-13.5%
RATE TYPE	E1	515	19.8%	91.1	94.5	0.16	0.09	0.08	0.02	-0.06	2.31	0.05	0.03	1.84	2.4%
	E6	134	5.1%	88.1	92.1	0.25	0.16	0.15	0.23	-0.27	1.89	0.10	0.07	1.60	5.6%
	ETOUB	147	5.6%	89.1	92.7	0.30	0.01	-0.05	0.01	-0.11	2.38	0.03	0.06	0.56	1.3%
	ETOUC	978	37.6%	85.8	90.3	0.44	0.24	0.14	0.15	0.12	1.53	0.21	0.02	9.96	14.0%
	ETOUD	396	15.2%	88.6	92.4	-0.12	0.54	0.35	0.21	-0.31	2.50	0.13	0.04	3.60	5.4%
	EV2A	433	16.6%	84.2	89.0	0.49	0.27	0.11	0.28	0.22	1.59	0.27	0.04	7.37	17.1%
SOLAR	No solar	1,480	56.9%	85.4	89.9	0.24	0.26	0.18	0.17	0.04	2.01	0.18	0.02	11.45	8.7%
	Solar	1,123	43.1%	89.8	93.5	0.36	0.23	0.09	0.13	-0.05	1.77	0.15	0.02	6.06	8.5%

Figure 17: Daily TOU Automated Response by Rate



KEY FINDINGS

- Nest and Emerson thermostats were used to automate daily TOU response. However, the number of Emerson devices with daily TOU response over the study period was too small for reliable load impact estimates.
- 57.9% of ecobee participants elected to automate their daily TOU response and set their preferences for tradeoffs between comfort and savings.
- The load impacts were analyzed using a matched control group and difference-in-differences.
- On the top 20 days, sites reduced demand by 0.19 kW across the 4-9 pm window.
- The demand reduction is weather-sensitive, as expected, and demand reduction is largest when temperatures are hottest.
- The demand reduction decays across the event hours; the reduction is largest in the first hour of the event, but drops for the second, third, and fourth hour regardless of when the event starts.
- The algorithms automated the demand response around the correct peak hours for rated TOU-C (4–9 pm) and TOU-D (5-8 pm).

INCREMENTAL EVENT IMPACTS FOR SITES WITH TIME OF USE AUTOMATION

This section focuses on the magnitude of event-based demand reduction delivered by sites with daily, automated response to TOU rates. The overall demand reduction for these sites has two distinct components – the daily automated TOU response (discussed in Section 4) and the event-based load reduction over and above the daily response. In both cases, the demand reduction is due to the thermostat algorithms and incremental to any behavioral response to TOU rates. Both the participants and the matched control group were on similar rates. This section focuses on the event-based demand reduction over and above daily TOU response.

EVENT DAY REDUCTION SUMMARY

Figure 18 visualizes per device impacts on September 8 and September 7. These days are notable because they were the two days with the highest PG&E system load over the study period. On September 8, both the PG&E and CAISO Net load peaked for the year, and the thermostats were dispatched from 6:00 pm to 9:00 pm. By contrast, on September 7, the thermostats were dispatched from 5:00 to 9:00 pm, producing the only four-hour event over hotter conditions. The daily TOU response from the ecobee devices is visible in the counterfactual.

Figure 18: Hourly Load Impacts on PG&E High System Load Days (Sites with Daily TOU Automation)

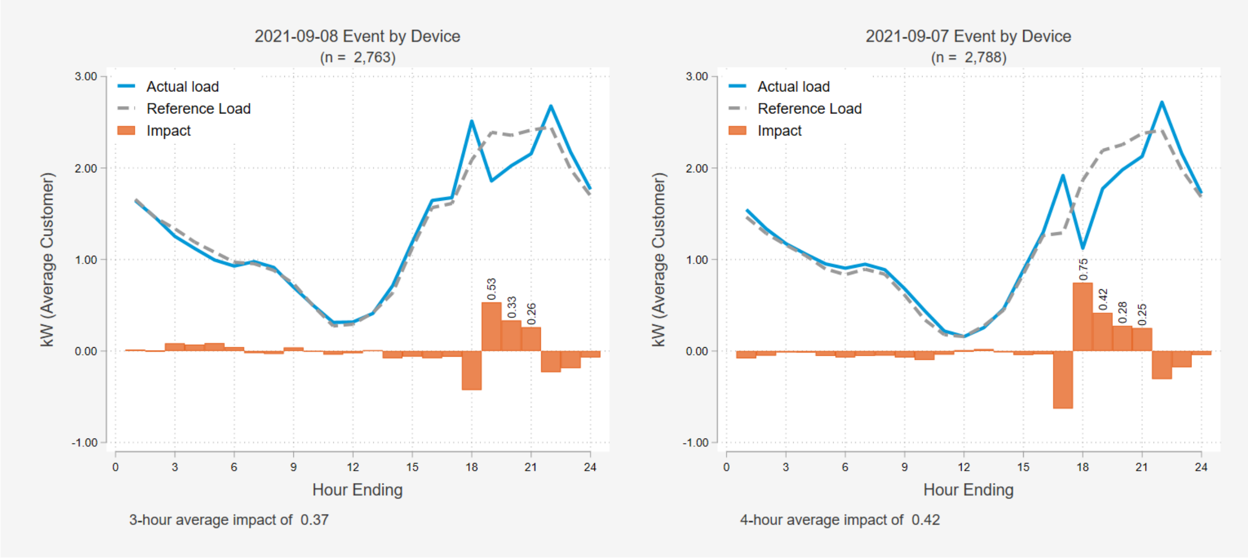


Table 14 shows reference loads, observed loads, impacts, and percent impacts for each of the fourteen PG&E summer 2021 DR events. As noted earlier, the study intentionally introduced variation in temperature conditions, event start times, and event duration in order to understand how performance varied under a wide range of conditions.

Table 12: Summary of 2021 Event Load Impacts (Sites with TOU Automation)

						Hourly Impacts				Event Average				
Date	Event Start	Event hours Avg. Temp	Max Temp (Participant weighted)	Treatment Sites	Control Sites	Hour 1	Hour 2	Hour 3	Hour 4	Reference Load (Baseline)	Impact	% Impact	se	t
7/29/2021	7:00 PM	86.7	93.1	2,361	-	0.69	0.46			2.33	0.58	24.7%	0.052	11.04
7/30/2021	3:00 PM	92.6	93.1	1,875	589	1.03	0.36	0.30		1.40	0.56	40.0%	0.068	8.25
8/11/2021	4:00 PM	91.2	92.4	2,342	603	0.75	0.39	0.31		1.55	0.48	31.0%	0.063	7.60
8/12/2021	4:00 PM	89.2	89.9	2,379	600	0.48	0.20			1.25	0.34	27.1%	0.064	5.31
8/14/2021	4:00 PM	90.1	91.4	2,416	611	0.56	0.23	0.20		1.65	0.33	20.0%	0.067	4.91
9/3/2021	6:00 PM	78.3	84.6	2,821	640	0.22	0.15	0.12		1.31	0.16	12.4%	0.049	3.32
9/5/2021	6:00 PM	86.7	94.5	2,834	627	0.60	0.31	0.25		1.99	0.39	19.5%	0.061	6.34
9/7/2021	5:00 PM	89.2	95.8	2,834	624	0.75	0.42	0.28	0.25	2.17	0.42	19.4%	0.059	7.19
9/8/2021	6:00 PM	86.2	96.7	2,833	625	0.53	0.33	0.26		2.39	0.37	15.7%	0.059	6.29
9/13/2021	5:00 PM	87.3	90.4	2,770	574	0.56	0.35	0.11		1.77	0.34	19.1%	0.051	6.69
9/14/2021	4:00 PM	88.8	89.0	2,713	628	0.42	0.16			1.24	0.29	23.7%	0.053	5.53
9/21/2021	4:00 PM	90.7	93.8	3,080	606	0.54	0.32	0.23	0.17	1.48	0.32	21.3%	0.052	6.14
9/23/2021	3:00 PM	90.5	91.3	3,108	578	0.75	0.32	0.22		1.01	0.43	42.9%	0.054	7.96
10/4/2021	4:00 PM	86.6	88.1	3,734	-	0.32	0.14	0.12		1.12	0.19	17.3%	0.023	8.26
Average Event		**88.1**	**91.7**	**2,721**	**522**	**0.59**	**0.30**	**0.22**	**0.21**	**1.64**	**0.37**	**22.7%**	**0.056**	**6.58**

IMPACTS BY THERMOSTAT TYPE

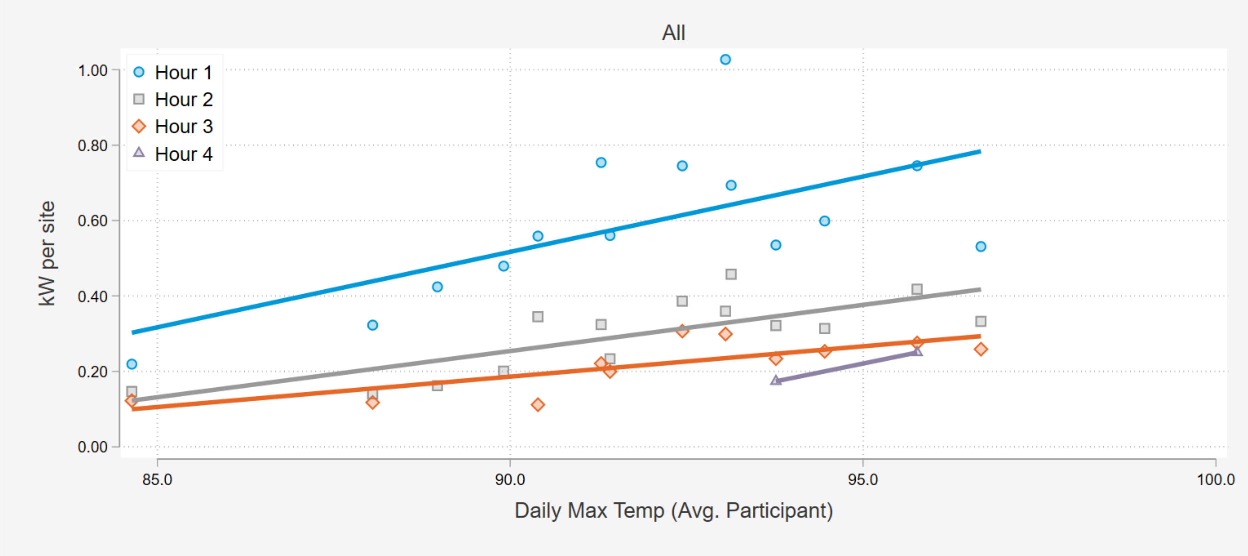
PG&E studied two of the three thermostats – ecobee and Emerson – which provided the ability to automate TOU response on a daily basis. Each thermostat incorporated different types of customer input, used different algorithms, and had a different customer base. However, of the 3,693 sites that opted for daily TOU automation by September 2021, 98.8% (3,648 sites) used ecobee devices, and only 1.2% (45 sites) had Emerson devices. Due to the small number of Emerson sites, the comparison of impacts by device type is not statistically significant.

WEATHER SENSITIVITY OF LOAD IMPACTS

As one might expect, the reduction delivered by thermostats tend to be larger when outdoor temperatures are higher. However, they are also defined by the number of hours into the event. Figure 19 visualizes the relationship between demand reduction and temperature and hours into the event.

In comparison to historical years, 2021 experienced temperate conditions. While the load impacts results record what was delivered, they do not reflect the full capability of the thermostats under more extreme conditions. They also only reflect the incremental response over and above the daily TOU response. Two notable related and previously mentioned observations are that the demand reduction is largest when temperatures are hottest and impacts decay across the event hours. The load impacts are largest in the first hour of the event but drop for the second, third, and fourth hour regardless of when the event starts.

Figure 19: Relationship between Demand Reduction, Weather, and Event Hour



LOAD IMPACTS BY CUSTOMER TYPE

PG&E has one of the most diverse service territories in the U.S. It provides electric service to approximately 16 million people, with over five million accounts, throughout a 70,000-square-mile service area in northern and central California. The service territory has extreme climate diversity ranging from more temperate coastal areas to hotter regions inland to mountainous areas. While the participants in the study are all early adopters, they still exhibit substantial diversity. Figure 20 shows the per-site load impacts for a wide range of customer categories and subcategories. Each dot represents an event. Because the event duration varied, the figure shows only the results for the first event hour. Table 15 provides additional detail for the average event hour. The differences shown are observational and should be interpreted with caution.

Figure 20: First Hour Per Site Impacts by Customer Segment

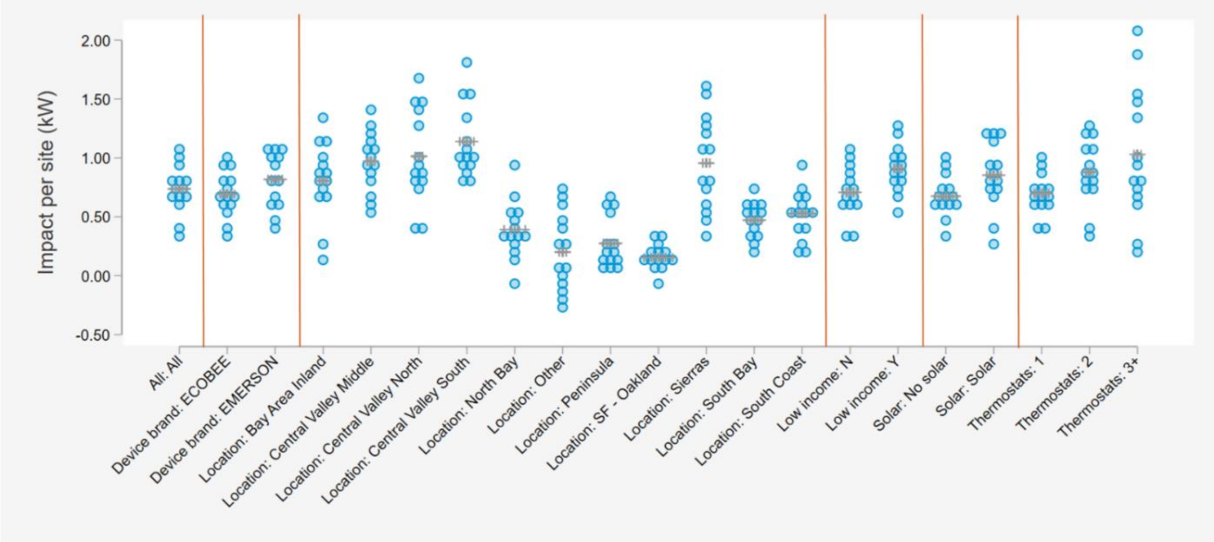


Table 13: Per Site Impacts by Customer Segment (Average Event Detail)

					Hour into event (Avg.)[1]				Event Hour Average[2]		
Category	Sub-category	% of Accounts	Event hours Avg. Temp	Max Temp (Participant weighted)	Hour 1	Hour 2	Hour 3	Hour 4	Reference Load (Baseline)	Impact	% Impact
All	All	100.0%	88.2	91.9	0.59	0.30	0.22	0.21	1.63	0.37	22.7%
Device brand	ECOBEE	99.1%	88.3	92.0	0.59	0.29	0.21	0.21	1.63	0.37	22.5%
	EMERSON	0.9%	83.2	87.3	0.40	0.41	0.31	0.29	1.15	0.37	32.4%
Geographic area	Bay Area Inland	18.9%	93.8	98.9	0.68	0.35	0.28	0.24	1.80	0.44	24.3%
	Central Valley Middle	12.9%	95.3	97.3	0.76	0.39	0.26	0.24	2.00	0.47	23.7%
	Central Valley North	1.9%	96.0	99.0	0.84	0.30	0.35	0.21	2.38	0.49	20.7%
	Central Valley South	14.6%	98.4	99.9	0.92	0.40	0.33	0.30	2.28	0.55	24.2%
	North Bay	4.4%	84.2	90.7	0.30	0.18	0.07	0.04	1.17	0.19	15.8%
	Other	0.8%	66.9	70.5	0.36	0.11	-0.02	0.11	0.71	0.16	22.9%
	Peninsula	3.7%	74.6	79.3	0.28	0.11	0.03	-0.02	0.94	0.14	14.9%
	San Francisco - Oakland	4.2%	73.4	77.3	0.10	0.05	0.06	-0.06	0.68	0.06	9.5%
	Sierras	7.2%	90.5	94.6	0.67	0.34	0.28	0.07	1.87	0.43	22.8%
	South Bay	29.7%	80.9	85.9	0.42	0.23	0.16	0.28	1.26	0.28	22.2%
	South Coast	1.6%	77.3	86.5	0.43	0.22	0.17	0.00	1.35	0.27	19.9%
Low income	No	90.7%	87.8	91.6	0.59	0.30	0.22	0.21	1.57	0.37	23.7%
	Yes	9.3%	92.5	95.0	0.58	0.25	0.20	0.19	2.19	0.35	15.8%
Number of thermostats	1 thermostat	77.0%	87.8	91.5	0.52	0.25	0.19	0.20	1.58	0.32	20.5%
	2 thermostats	20.5%	89.3	93.1	0.75	0.43	0.30	0.24	1.75	0.50	28.3%
	3+ thermostats	2.5%	90.8	94.2	1.09	0.62	0.37	0.42	2.25	0.70	31.2%
Solar	No solar	59.9%	86.4	90.5	0.53	0.26	0.19	0.18	1.74	0.33	18.8%
	Solar	40.1%	90.9	94.1	0.66	0.34	0.26	0.26	1.47	0.42	28.9%

[1] The average reduction for the hour into the event. The dates included differ for 3 and 4 hours events since not all events lasted that long.
[2] The average across all event hours regardless of timing or duration of events

KEY FINDINGS

- The demand reduction delivered by sites that opted for thermostat daily TOU automation have two components: the daily TOU response (Section 4) and event-based response over and above the daily TOU response enabled by the thermostat.
- The demand reduction was analyzed using a randomized control trial and a difference-in-differences panel regression. For twelve events, a subset of participants was randomly assigned to the control group in order to produce a baseline of load patterns absent curtailment instructions. For two events, PG&E intentionally dispatched all participants in order to assess the full reduction capability.
- The demand reduction is largest when temperatures are hottest, but the magnitude of the reduction varies by event hour.
- The demand reduction decays across the event hours. The load impacts are largest in the first hour of the event but drop for the second, third, and fourth hour regardless of when the event starts.
- Multiple devices at the site do not lead to double the impacts. Sites with two devices delivered about 1.25x the reduction of sites with a single device. Thus, some caution is needed in enrolling sites with multiple devices.
- PG&E should concentrate its targeting and enrollment efforts in the Central Valley, the Bay Area Inland area surrounding the I-680 corridor, areas of the South Bay, and the Sierras. Load reduction may be too small to pursue in specific regions such as San Francisco-Oakland, the Peninsula, and the North Bay. However, we also recognize that PG&E is working directly with the thermostat manufacturers and does not control all aspects of the recruitment efforts.
- The load impacts from the different thermostat brands were similar, with small differences. After controlling for weather, hour-of-day, and hours into the event, the load impacts for Emerson devices are roughly 10% higher than ecobee devices. The difference in load impacts between ecobee and Nest thermostats was not statistically significant

EVENT IMPACTS FOR SITES WITHOUT TIME OF USE AUTOMATION

This section focuses on the magnitude of demand reduction delivered by PG&E without time of use automation during 2021 event days. The results for sites with TOU automation are presented separately since the overall load impact for those sites is parsed into two components – daily, automated TOU response and event-based dispatchable load reduction. The magnitude of demand reduction is a function of several factors – temperature, time of day, hours into the event, and customer behavior. This section documents the demand reduction for each event, the impacts by thermostat type, the load impacts for different customer segments, and the weather sensitivity of the resource. We conclude by summarizing the key findings.

EVENT DAY REDUCTION SUMMARY

Figure 21 visualizes per device impacts on September 8 and September 7. These days are notable because they were the two days with the highest PG&E system load over the study period. On September 8, both the PG&E and CAISO Net load reached their peak for the year, and the thermostats were dispatched from 6:00 pm through 9:00 pm. By contrast, on September 7, the thermostats were dispatched from 5:00 to 9:00 pm, producing the only four-hour event.

Figure 21: Hourly Load Impacts on PG&E High System Load Days (Sites without TOU automation)

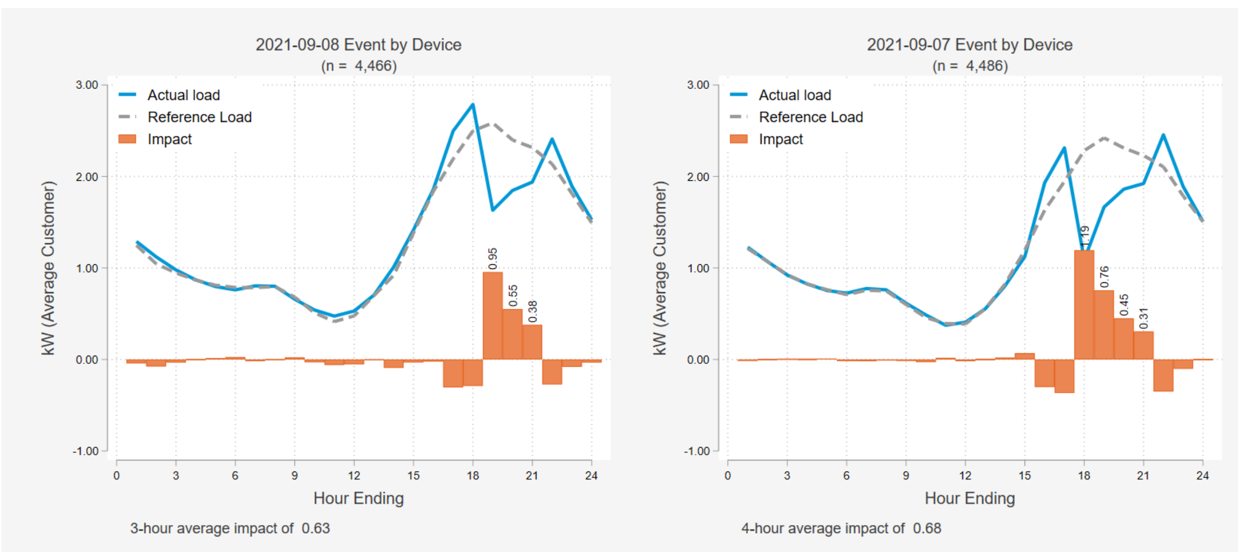


Table 14 shows reference loads, observed loads, impacts, and percent impacts for each of the fourteen PG&E summer 2021 DR events. As noted earlier, the study intentionally introduced variation in temperature conditions, event start times, and event duration in order to understand how performance varied under a wide range of conditions.

Table 14: Summary of 2021 Event Load Impacts

Date	Event Start	Event hours Avg. Temp	Max Temp (Participant weighted)	Control Sites	Treament Sites	Hourly Impacts: Hour 1	Hour 2	Hour 3	Hour 4	Event Average: Reference Load (Baseline)	Impact	% Impact	se	t
7/29/2021	7:00 PM	88.4	94.7	-	4,192	0.96	0.64			2.43	0.80	32.9%	0.058	13.77
7/30/2021	3:00 PM	94.0	96.0	1,255	3,315	0.91	0.76	0.49		2.00	0.72	36.1%	0.065	11.07
8/11/2021	4:00 PM	94.5	98.3	1,694	5,350	1.33	0.94	0.53		2.19	0.93	42.6%	0.051	18.17
8/12/2021	4:00 PM	92.1	95.0	1,668	5,202	0.92	0.65			1.89	0.78	41.6%	0.051	15.37
8/14/2021	4:00 PM	93.7	98.3	1,688	5,330	1.04	0.68	0.42		2.16	0.71	33.0%	0.054	13.22
9/3/2021	6:00 PM	79.5	85.7	2,023	7,252	0.45	0.28	0.21		1.33	0.31	23.6%	0.033	9.63
9/5/2021	6:00 PM	87.9	95.2	2,021	7,263	0.75	0.45	0.28		1.88	0.49	26.4%	0.041	11.98
9/7/2021	5:00 PM	90.2	96.9	2,016	7,285	1.19	0.76	0.45	0.31	2.31	0.68	29.3%	0.041	16.36
9/8/2021	6:00 PM	87.6	97.5	2,026	7,285	0.95	0.55	0.38		2.43	0.63	25.8%	0.042	15.00
9/13/2021	5:00 PM	88.3	91.5	2,046	7,368	0.82	0.50	0.28		1.87	0.53	28.5%	0.035	15.22
9/14/2021	4:00 PM	89.8	90.5	2,025	7,113	0.73	0.51			1.60	0.62	38.8%	0.037	16.94
9/21/2021	4:00 PM	90.7	93.9	2,264	8,780	0.71	0.54	0.35	0.22	1.61	0.45	28.2%	0.032	14.17
9/23/2021	3:00 PM	90.5	91.8	2,259	8,781	0.61	0.57	0.43		1.23	0.54	43.8%	0.033	16.46
10/4/2021	4:00 PM	86.6	88.4	-	11,193	0.47	0.37	0.25		1.25	0.37	29.4%	0.015	24.26
Average Event		**89.6**	**93.8**			**0.85**	**0.59**	**0.37**	**0.26**	**1.80**	**0.57**	31.6%	**0.044**	**12.94**

IMPACTS BY THERMOSTAT TYPE

PG&E included three different types of thermostats in the study. Table 15 compares the load impacts by date and hour for each device brand. Despite the underlying differences, the load impact for all three thermostat brands was similar. All of the device brands delivered larger demand reduction when conditions were hotter, and all of them delivered the largest reduction in the first hours of the event. On average, load reduction from ecobee devices was slightly lower for later event hours, but this was offset by their higher participation rates. After controlling for weather, hour-of-day, and hours into the event, the load impacts for Emerson devices are roughly 10% higher than ecobee devices. The difference in load impacts between ecobee and Nest thermostats was not statistically significant. Appendix A includes additional detail.

Table 15: Ex-Post Load Impacts by Device Brand

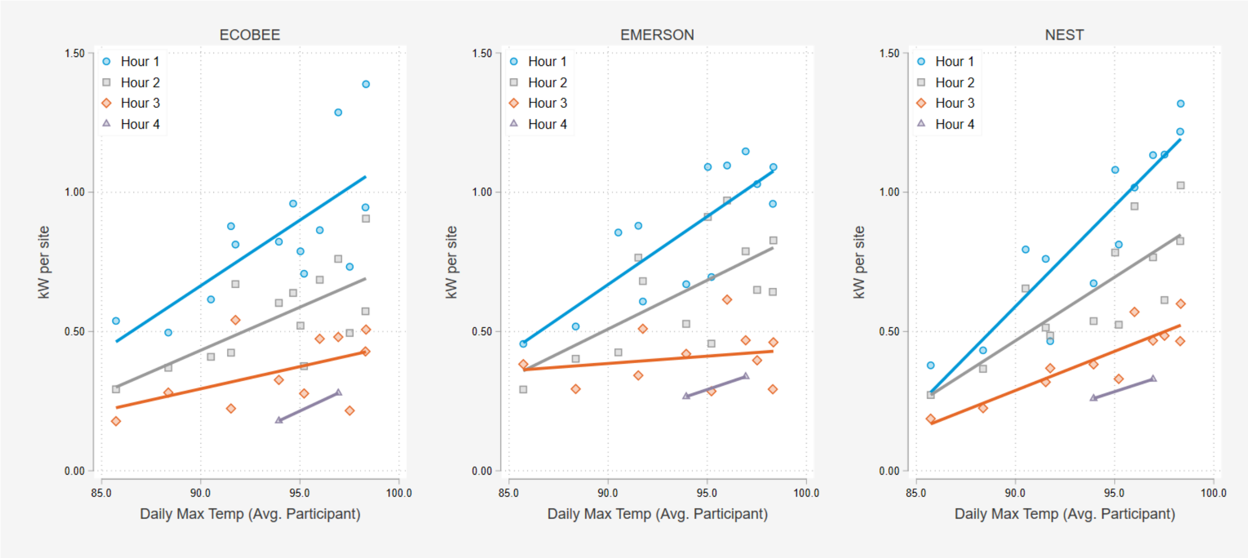
Date	Event Start	Max Temp (DR-5)	Max Temp (Participant weighted)	ECOBEE Hour 1	ECOBEE Hour 2	ECOBEE Hour 3	ECOBEE Hour 4	EMERSON Hour 1	EMERSON Hour 2	EMERSON Hour 3	EMERSON Hour 4	NEST Hour 1	NEST Hour 2	NEST Hour 3	NEST Hour 4
7/29/2021	7:00 PM	98.8	94.7	0.96	0.64										
7/30/2021	3:00 PM	99.0	96.0	0.86	0.69	0.47		1.10	0.97	0.61		1.02	0.95	0.57	
8/11/2021	4:00 PM	98.2	98.3	1.39	0.91	0.51		1.09	0.83	0.46		1.32	1.02	0.60	
8/12/2021	4:00 PM	95.6	95.0	0.79	0.52			1.09	0.91			1.08	0.78		
8/14/2021	4:00 PM	96.8	98.3	0.95	0.57	0.43		0.96	0.64	0.29		1.22	0.82	0.47	
9/3/2021	6:00 PM	87.8	85.7	0.54	0.29	0.18		0.46	0.29	0.38		0.38	0.27	0.19	
9/5/2021	6:00 PM	97.0	95.2	0.71	0.38	0.28		0.70	0.46	0.29		0.81	0.52	0.33	
9/7/2021	5:00 PM	100.6	96.9	1.29	0.76	0.48	0.28	1.15	0.79	0.47	0.34	1.13	0.77	0.47	0.33
9/8/2021	6:00 PM	101.4	97.5	0.73	0.49	0.22		1.03	0.65	0.40		1.14	0.61	0.49	
9/13/2021	5:00 PM	94.8	91.5	0.88	0.42	0.22		0.88	0.77	0.34		0.76	0.51	0.32	
9/14/2021	4:00 PM	95.4	90.5	0.62	0.41			0.86	0.43			0.79	0.65		
9/21/2021	4:00 PM	94.0	93.9	0.82	0.60	0.33	0.18	0.67	0.53	0.42	0.27	0.67	0.54	0.38	0.26
9/23/2021	3:00 PM	93.8	91.8	0.81	0.67	0.54		0.61	0.68	0.51		0.47	0.49	0.37	
10/4/2021	4:00 PM	89.6	88.4	0.50	0.37	0.28		0.52	0.40	0.29		0.43	0.37	0.22	
Hourly average		95.9	93.8	0.85	0.55	0.36	0.23	0.85	0.64	0.41	0.30	0.86	0.64	0.40	0.29
Average				0.50				0.55				0.55			

WEATHER SENSITIVITY OF LOAD IMPACTS

As one might expect, the reduction delivered by thermostats tends to be larger when outdoor temperatures are higher. However, they are also defined by the number of hours into the event. Figure 22 visualizes the relationship between demand reduction and temperature and hours of the event by thermostat brand.

In comparison to historical years, 2021 experienced temperate conditions. While the load impact results record what was delivered, they do not reflect the full capability of the thermostats under more extreme conditions. They only reflect the incremental response over and above the daily TOU response. Two notable observations are that the reduction is largest when temperatures are hottest and impacts decay across the event hours. The load impacts are largest in the first hour of the event but decline for the second, third, and fourth hour regardless of when the event starts.

Figure 22: Relationship between Demand Reduction, Weather, and Event Hour



During the first hour, load impacts exceed 1 kW per device when the daily max temperature exceed 98F, but demand reduction is lower for subsequent hours. The performance patterns in Figure 22 were used to estimate the per device demand reduction capability under different weather conditions for operation planning.

LOAD IMPACTS BY CUSTOMER TYPE

PG&E has one of the most diverse service territories in the U.S. It provides electric service to approximately 16 million people, with over five million accounts, throughout a 70,000-square-mile service area in northern and central California. Its territory has extreme climate diversity ranging from more temperate coastal areas to hotter regions inland to mountainous areas. While the participants in the study are all early adopters, they still exhibit substantial diversity.

Figure 23 shows the per-site load impacts for several customer categories and subcategories. Each dot represents an event, and the gray horizontal line is the median value. Because the event durations varied, the figure shows only the results for the first event hour.

Figure 23: Per Site Impacts by Customer Segment

Table 16 provides additional detail about the load impacts, including the share of sites in each segment and the weather conditions. The differences are observational rather than causal and should be interpreted with caution.

Table 16: Per Site Impacts by Customer Segment Detail

					Hour into event (Avg.)[1]				Event Hour Average[2]		
Category	Sub-category	% of Accounts	Event hours Avg. Temp	Max Temp (Participant weighted)	Hour 1	Hour 2	Hour 3	Hour 4	Reference Load (Baseline)	Impact	% Impact
All	All	100.0%	89.6	93.0	0.85	0.59	0.37	0.26	1.87	0.60	32.2%
Device brand	ECOBEE	43.4%	89.6	93.0	0.85	0.55	0.36	0.23	2.00	0.58	29.2%
	EMERSON	6.1%	88.0	91.3	0.85	0.64	0.41	0.30	1.76	0.63	35.6%
	NEST	50.4%	90.2	93.6	0.86	0.64	0.40	0.29	1.75	0.63	36.0%
Geographic area	Bay Area Inland	19.9%	93.7	98.6	0.89	0.63	0.39	0.32	1.89	0.64	33.7%
	Central Valley Middle	14.2%	95.3	97.2	1.10	0.73	0.47	0.20	2.20	0.76	34.6%
	Central Valley North	2.5%	95.9	98.9	1.09	0.72	0.43	0.29	2.22	0.75	33.7%
	Central Valley South	17.0%	98.4	99.9	1.27	0.76	0.46	0.20	2.47	0.83	33.5%
	North Bay	4.9%	84.1	90.7	0.47	0.41	0.26	0.14	1.39	0.38	27.1%
	Other	0.7%	66.2	70.2	0.19	0.04	0.14	0.05	0.84	0.12	14.1%
	Peninsula	3.7%	74.3	78.9	0.24	0.16	0.10	0.11	1.12	0.17	15.5%
	San Francisco - Oakland	3.8%	73.8	77.7	0.18	0.15	0.14	0.08	0.81	0.16	19.4%
	Sierras	6.8%	90.2	94.3	1.12	0.77	0.48	0.51	2.28	0.80	35.0%
	South Bay	24.7%	80.9	85.9	0.51	0.38	0.28	0.31	1.37	0.39	28.7%
	South Coast	1.7%	79.3	88.7	0.61	0.42	0.26	0.15	1.50	0.43	28.8%
Low income	No	82.9%	88.6	92.4	0.81	0.58	0.38	0.27	1.77	0.59	33.1%
	Yes	17.1%	94.0	96.3	1.03	0.61	0.32	0.23	2.30	0.66	28.7%
Number of thermostats	1 thermostat	82.5%	89.4	92.8	0.82	0.55	0.34	0.23	1.84	0.57	30.9%
	2 thermostats	15.9%	90.5	94.2	0.99	0.76	0.52	0.43	1.98	0.76	38.3%
	3+ thermostats	1.6%	89.2	92.7	0.97	0.73	0.39	0.31	2.09	0.70	33.4%
Solar	No solar	72.4%	88.8	92.4	0.76	0.52	0.32	0.23	1.90	0.54	28.2%
	Solar	27.6%	91.6	94.7	1.05	0.74	0.49	0.35	1.77	0.76	43.1%

[1] The average reduction for the hour into the event. The dates included differ for 3 and 4 hours events since not all events lasted that long.

[2] The average across all event hours regardless of timing or duration of events

KEY FINDINGS

- Event day response for sites without daily TOU automation is not directly comparable to sites that provide daily demand reduction.
- The events were analyzed using a randomized control trial and a difference-in-differences panel regression. For twelve events, a subset of participants was randomly assigned to the control group in order to produce a baseline of load patterns absent curtailment instructions. PG&E intentionally dispatched all participants for two events to test the full reduction capability.
- The demand reduction is largest when temperatures are hottest, but the magnitude of the reduction varies by event hour.
- The demand reduction decays across the event hours. The load impacts are largest in the first hour of the event but drop for the second, third, and fourth hour regardless of when the event starts.
- The load impacts from the different thermostat brands were similar, with small differences. After controlling for weather, hour-of-day, and hours into the event, the load impacts for Emerson devices are roughly 10% higher than ecobee devices. The difference in load impacts between ecobee and Nest thermostats was not statistically significant
- Multiple devices at the site do not lead to double the impacts. Sites with two devices delivered about 1.25x the reduction of sites with a single device. Thus, some caution is needed in enrolling sites with multiple devices.
- PG&E should concentrate its targeting and enrollment efforts in the Central Valley, the Bay Area Inland area surrounding the I-680 corridor, areas of the South Bay, and the Sierras. Load reduction may be too small to pursue in specific regions such as San Francisco-Oakland, the Peninsula, and the North Bay. However, we also recognize that PG&E is working directly with the thermostat manufacturers and does not control all aspects of the recruitment efforts.

RECOMMENDATIONS

PG&E initiated the study to assess the ability of three types of WiFi-connected thermostats – Nest, Ecobee, and Emerson – to deliver daily automated response to time of use rates in addition to event-based response. The study recruited over 12,000 sites and relied on randomized control trial to measure event impacts. Because the objective was to learn quickly, PG&E intentionally called fourteen events and introduced variation in weather, hours of dispatch, event duration, and day type. A key objective was to learn how the technology performs under different conditions, allowing PG&E to measure the technologies contribution toward resource adequacy and develop models to allow the resource to be bid into electricity markets. The thermostats can deliver flexible loads at very fast ramp rates, are available for a wide range of hours, and can target resources to specific geographic locations.

Most importantly, the thermostats deliver larger reduction when the weather is more extreme, and resources are needed most. PG&E has received approval to conduct a two-year pilot in 2022 and 2023 and intends to integrate the program into the CAISO electric wholesale market either in 2023 or 2024, dependent upon CPUC approval. As a result, the recommendations are designed to deliver additional insights into the program operations and improve the value of the resources.

Table 17: Evaluator Recommendations

Recommendation	Explanation
Develop and use a time-temperature matrix to assist with operations and estimates for planning conditions	PG&E, CAISO, planners, and program managers need to understand the magnitude of resources available for different hours under various temperature conditions. A time-temperature matrix quantifies the relationship between demand reduction, daily temperature conditions, and hour-of-day. It describes the magnitude of resources available based on weather conditions, the timing of dispatch, and the mix of participants. We recommend that PG&E base the time-temperature matrix on the same model used to estimate the demand reduction capability under standardized planning conditions.
For the summer of 2022, use and operations plan and call more events with fewer sites – rotating across customers while using random assignment	The main objective of any new technology study is to learn as much as possible as quickly as possible, so the full-scale rollout and operations can be optimized. In 2021, for most events, PG&E dispatched the majority of enrolled sites and held back a smaller control group. For the summer of 2022, we recommend that PG&E randomly assign the population to ten groups. For each event, we recommend PG&E dispatch one of two groups and withhold the remainder of the groups to serve as controls. For emergency events, we recommend that PG&E dispatches all resources. The recommended approach allows PG&E to call more events while reducing the number of event hours each individual customer experiences. Thus, it allows PG&E to gain over one summer the experience

Recommendation	Explanation
	with operations that, if left to weather and market operations alone, could take multiple years to capture.
Test how thermostats perform for longer events and in later hours.	For the study, the maximum event duration is four hours, and the resource availability is limited to 12-9 pm. PG&E should conduct more tests of longer duration events and test load impacts for later event hours that better coincide with the net load peak. In addition, PG&E should work with thermostat manufacturers to allow longer events (e.g., 5-6 hours) under emergency conditions and to allow thermostats to be dispatched in the 9-10 pm hour. The ability to dispatch resources for longer periods is directly linked to cost-effectiveness. While the 9-10 pm hour is not a resource adequacy concern in 2022-2023, the resource adequacy modeling indicates that net load peaks are likely to shift to later hours.
Either modify TOU rates or work with manufacturers to focus daily TOU automated load shifting on net load peak hours	The daily TOU automation consistently shifts loads away from peak hours (4-9 pm). However, demand reduction is largest in earlier hours (4-7 pm) and smaller during the net load peak hours (7-9 pm). The one exception was customers on the TOU-D rate, which shifted load over a narrower period (5-8 pm) and generally delivered larger demand reduction. The value of the daily demand reduction to the grid is optimized by focusing them on net load peak hours. This can be accomplished either by working directly with manufacturers or by modifying rates to reflect the higher value on net peak hours.
Target customers in hotter regions who use air conditioners coincident with peak hours	The evaluation found that customers who delivered smaller demand reduction were located in specific parts of the territory – the San Francisco-Oakland region, Peninsula, and North Bay –with a more temperate climate. To the extent possible, PG&E should limit marketing to customers in those areas and focus on customers in hotter regions with air conditioner use coincident with peak hours. As part of the effort, we recommend that PG&E update its models that use AMI data to estimate hourly peak day air conditioner loads on peak days. The estimates of site-level hourly AC loads should be incorporated into targeting efforts.
Use the results from the study to develop a model for bidding dispatchable resources into CAISO	The study has produced a wealth of information by intentionally introducing variation in event weather conditions, start times, and duration. The two-year pilot will add to the body of evidence and, hopefully, include more data with hotter weather conditions. We recommend that PG&E use the data to build a predictive model that can both be used for long-term system planning and for operations. The long term planning requires estimating resources under standard planning conditions. By contrast, operations require daily forecasts of the hourly resource capability so that PG&E can bid resources into the CAISO market.

Recommendation	Explanation
Either modify TOU rates or work with manufacturers to focus daily TOU automated load shifting on net load peak hours	The daily TOU automation consistently shifts loads away from peak hours (4-9 pm). However, demand reduction is largest in earlier hours (4-7pm) and smaller on the net load peak hours (7-9 pm). The one exception is customers on the TOU-D rate which shifted load over a narrower period (5-8 pm) and generally delivered larger demand reduction. The value of the daily demand reduction to the grid is optimized by focusing them on net load peak hours. This can be accomplished either by working directly with manufacturers or by modifying rates to reflect the higher value on net peak hours.
Evaluate 1st year impacts for all sites that reached a full year of experience with daily automated time-of-use rates.	Evaluate 1st year impacts for all sites that reached a full year of experience with daily automated time-of-use rates. Currently, the evaluation includes all incremental sites that enrolled on the rate over the study period. As a result, the number of sites evaluated for earlier events is small and grows during the study period. The approach creates two challenges. The sample size for early months is inherently small, and we have very little data on behavior with TOU rates for the most recent enrollments. Shifting from analyzing sites that enrolled over the study period to analyzing sites that reached a full year of experience under TOU rates addresses these challenges. It ensures a large enough number of sites are analyzed each month and ensures we fully factor in the behavior of each new enrollment.

APPENDIX A: PERFORMANCE BY DEVICE TYPE

The below 2nd stage model assesses performance by thermostat brand, after controlling for weather conditions, the event start time, and hours into the event. The underlying data is the individual event hour results for each event by device type for sites without daily TOU automation.

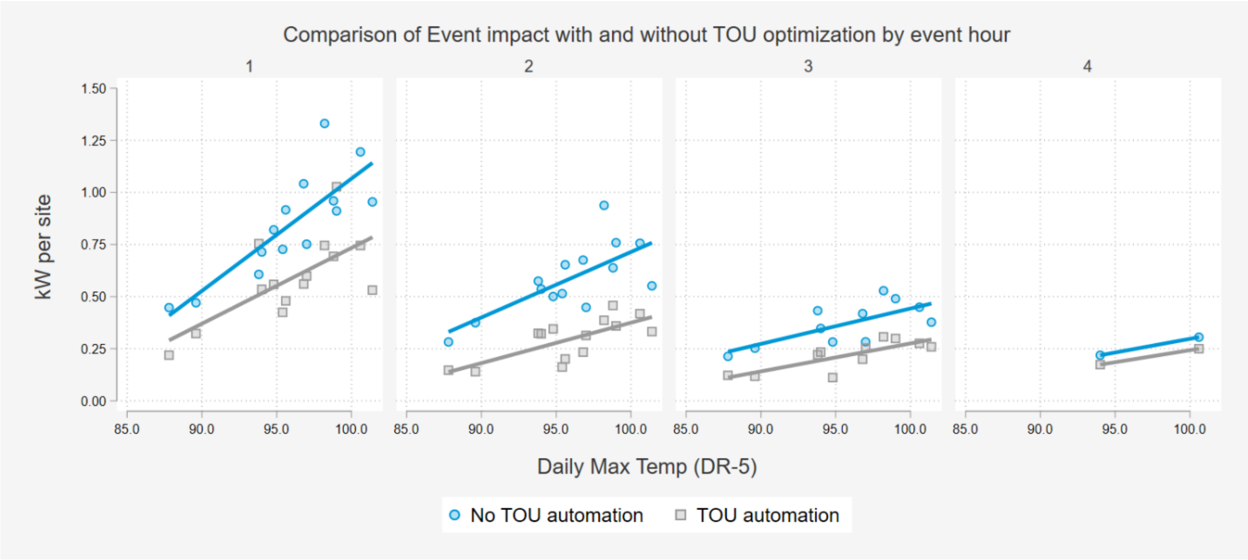
```
HDFE Linear regression                            Number of obs   =        119
Absorbing 1 HDFE group                            F(  14,      13) =          .
Statistics robust to heteroskedasticity           Prob > F        =          .
                                                  R-squared       =     0.8520
                                                  Adj R-squared   =     0.8321
                                                  Within R-sq.    =     0.8520
Number of clusters (date)    =         14         Root MSE        =     0.1993

                                  (Std. Err. adjusted for 14 clusters in date)
------------------------------------------------------------------------------
             |               Robust
    lnimpact |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
       cdd70 |   .0961112   .0118387     8.12   0.000     .0705352    .1216872
             |
hour#c.cdd70 |
         17  |   .0265774   .0097016     2.74   0.017     .0056183    .0475366
         18  |   .0254494    .008583     2.97   0.011     .0069071    .0439918
         19  |  -.0001499   .0116214    -0.01   0.990    -.0252563    .0249566
         20  |  -.0226814   .0143485    -1.58   0.138    -.0536794    .0083167
         21  |  -.0417128   .0232964    -1.79   0.097    -.0920415    .0086159
             |
  event_hour |
          2  |  -.2908007   .0811306    -3.58   0.003    -.4660727   -.1155286
          3  |  -.6745115   .1203966    -5.60   0.000    -.9346126   -.4144104
          4  |  -1.390499    .147603    -9.42   0.000    -1.709376   -1.071622
             |
       cdd70 |          0  (omitted)
             |
 event_hour# |
     c.cdd70 |
          2  |  -.0035352   .0125849    -0.28   0.783    -.0307233    .0236529
          3  |   .0033938   .0188652     0.18   0.860    -.0373619    .0441495
          4  |    .066095   .0375454     1.76   0.102    -.0150169     .147207
             |
 devicebrand |
    EMERSON  |    .103623   .0506247     2.05   0.061    -.0057451    .2129911
       NEST  |   .0504059   .0712152     0.71   0.492    -.1034452    .2042569
             |
       _cons |  -.8343729   .0541342   -15.41   0.000    -.9513227   -.7174231
------------------------------------------------------------------------------
```

APPENDIX B: COMPARISON OF EVENT DAY RESPONSE WITH AND WITHOUT AUTOMATED DAILY TOU RESPONSE

As noted in the main report, roughly 58% of ecobee participants opted to use their thermostats to automate their daily TOU response. For sites that elected for daily TOU automation, the overall reduction has two components: the daily response and the incremental event-based response. By contrast sites that were not reducing daily, delivered larger response in event days because they were not reducing loads during non-event days. Figure 24 shows the differences in the magnitude of reduction by hours into the event.

We also show the results of a second stage regression – a regression of hourly load impacts – designed to quantify the difference in event day response between the sites with and without daily TOU automation. The event day impacts for sites with daily TOU automation were lower by 0.26, 0.25, 0.14, and 0.02 kW in event hours 1, 2, 3, and 4, respectively. The magnitude of the difference matches the magnitude of reduction due to the daily TOU automation (see Section 4). In other words, when we combine the daily response and incremental event-based response, the overall magnitude of demand reduction on event days is similar to the event reduction for sites without daily TOU automated response. The main differences is that the daily response helps customer reduce their bills more, and also provides a daily load shifting away from peak hours.

Figure 24: Ecobee Event Based Response Sites with and without Daily TOU Automation



```
HDFE Linear regression                            Number of obs     =         82
Absorbing 1 HDFE group                            F(  16,       13) =          .
Statistics robust to heteroskedasticity           Prob > F          =          .
                                                  R-squared         =     0.8276
                                                  Adj R-squared     =     0.7852
                                                  Within R-sq.      =     0.8276
Number of clusters (date)     =         14        Root MSE          =     0.1197

                                 (Std. Err. adjusted for 14 clusters in date)
```

impact	Coef.	Robust Std. Err.	t	P>|t|	[95% Conf.	Interval]
cdd70	.0849968	.0154362	5.51	0.000	.0516489	.1183447
hour#c.cdd70						
17	-.0317531	.0163181	-1.95	0.074	-.0670062	.0035
18	-.0306562	.0173606	-1.77	0.101	-.0681614	.0068491
19	-.0412841	.0198928	-2.08	0.058	-.0842599	.0016918
20	-.0434078	.0183954	-2.36	0.035	-.0831487	-.0036669
21	-.0429712	.0217923	-1.97	0.070	-.0900505	.0041082
event_hour						
2	-.1826223	.0386502	-4.73	0.000	-.2661208	-.0991237
3	-.2955079	.0505263	-5.85	0.000	-.4046634	-.1863525
4	-.4887178	.1023265	-4.78	0.000	-.7097807	-.2676549
cdd70	0	(omitted)				
event_hour# c.cdd70						
2	-.0157487	.0078006	-2.02	0.065	-.0326008	.0011035
3	-.0266755	.0092495	-2.88	0.013	-.0466579	-.0066931
4	-.0184775	.0257404	-0.72	0.486	-.0740864	.0371313
event_hour# c.tou_auto						
1	-.2612198	.0522963	-4.99	0.000	-.3741991	-.1482405
2	-.253068	.0367288	-6.89	0.000	-.3324158	-.1737203
3	-.1424928	.0361057	-3.95	0.002	-.2204943	-.0644912
4	-.0174551	.0130769	-1.33	0.205	-.0457061	.0107959
_cons	.56041	.0498382	11.24	0.000	.4527411	.6680789

```
HDFE Linear regression                            Number of obs   =         82
Absorbing 1 HDFE group                            F(  16,     13) =          .
Statistics robust to heteroskedasticity           Prob > F        =          .
                                                  R-squared       =     0.8276
                                                  Adj R-squared   =     0.7852
                                                  Within R-sq.    =     0.8276
Number of clusters (date)    =         14         Root MSE        =     0.1197

                                  (Std. Err. adjusted for 14 clusters in date)
------------------------------------------------------------------------------
             |               Robust
      impact |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
       cdd70 |   .0849968   .0154362     5.51   0.000     .0516489    .1183447
             |
hour#c.cdd70 |
         17  |  -.0317531   .0163181    -1.95   0.074    -.0670062       .0035
         18  |  -.0306562   .0173606    -1.77   0.101    -.0681614    .0068491
         19  |  -.0412841   .0198928    -2.08   0.058    -.0842599    .0016918
         20  |  -.0434078   .0183954    -2.36   0.035    -.0831487   -.0036669
         21  |  -.0429712   .0217923    -1.97   0.070    -.0900505    .0041082
             |
  event_hour |
          2  |  -.1826223   .0386502    -4.73   0.000    -.2661208   -.0991237
          3  |  -.2955079   .0505263    -5.85   0.000    -.4046634   -.1863525
          4  |  -.4887178   .1023265    -4.78   0.000    -.7097807   -.2676549
             |
       cdd70 |          0  (omitted)
             |
  event_hour#|
     c.cdd70 |
          2  |  -.0157487   .0078006    -2.02   0.065    -.0326008    .0011035
          3  |  -.0266755   .0092495    -2.88   0.013    -.0466579   -.0066931
          4  |  -.0184775   .0257404    -0.72   0.486    -.0740864    .0371313
             |
  event_hour#|
  c.tou_auto |
          1  |  -.2612198   .0522963    -4.99   0.000    -.3741991   -.1482405
          2  |   -.253068   .0367288    -6.89   0.000    -.3324158   -.1737203
          3  |  -.1424928   .0361057    -3.95   0.002    -.2204943   -.0644912
          4  |  -.0174551   .0130769    -1.33   0.205    -.0457061    .0107959
             |
       _cons |     .56041   .0498382    11.24   0.000     .4527411    .6680789
------------------------------------------------------------------------------
```

APPENDIX C: TOU AUTOMATION CONTROL GROUP SELECTION

The evaluation of the TOU automation load impacts was estimated using a matched control group. There are different techniques – Euclidian distance, propensity score matching, stratified matching - that can be used to identify a matched control group. This section documents how the matched control group was selected and the quality of the matched control group (before the differences-in-differences estimation).

Rather than pre-determine the method and model used to select the matched control group, we held a tournament to identify the most accurate matched control group approach. Table summarizes the key elements.

Table 18: TOU Automation Control Group Selection

COMPONENT	ANSWER
What population was used a control group? And how many sites did it include?	The control pool was comprised of PG&E customers with ecobee thermostats that participated in event-based DR but did not accept the daily TOU automation offer. Of all the participants, 42.1% did not agree to daily TOU automation. The numbers varied over the course of the summer, but by September 30, 2021, the control pool included 2,657 customers.
Was matching done with or without replacement?	Matching was done with replacement, meaning that the same control pool candidate could be matched to more than one TOU automation (treatment) participant if they were the best match.
What characteristics were included in the matching?	The matching was selected based a tournament of six different combinations of methods and models. The final model included the following characteristics: - Geograhic region (11) - Solar status and size of solar system - EV status - Battery storage and size of battery - Rate type (Flat rate, TOU rate, EV rate) - Average summer loads by time of day in 3-hour intervals - 5 customer size bins, designed so each bin include 20% of kwh across the candidate pool - Customer peak load percentile (0-100) - Monthly energy usage patterns (May-October)

COMPONENT	ANSWER
The matching included customer loads. What time frame was included in the matching?	The load characteristics were strictly based on pre-enrollment (for both TOU automation and control candidate sites). Load characteristics were calculated for May-October 2020.
How was the best matching method and model identified?	The best method and model combination was identified by comparing the loads for the treatment and matched control group out-of-sample, during a pre-enrollment period. The matching was done using May-October 2020 loads and the accuracy of the control groups was assessed using April-June 2021 pre-treatment data. The thermostats enrollments did not start until late July 2021. We selected the matched control group that best mirrored the participant group (in aggregate), as measured by CVRMSE, in the out-of-sample test. The below table shows how well TOU automation and matched control group characteristics compared to each other using t-tests.

Table 19: Comparison of TOU automation group and matched controls

Category	Variable	Treat (N=2,658)	Control (N=2,658)	Std. Error of the diff	t or z stat	p-val
Distributed Generation	Solar (%)	43.1%	43.1%	0.014	0.00	1.000
	Battery Storage (%)	3.8%	4.0%	0.005	-0.28	0.776
	Solar capacity (Avg. kW)	2.56	2.52	0.093	0.49	0.623
	Storage capacity (Avg. kW)	0.27	0.31	0.044	-0.95	0.340
Rates	Flat rate (e.g., E1)	19.5%	19.9%	0.011	-0.34	0.730
	TOU rate	63.9%	63.6%	0.013	0.23	0.819
	EV rate	16.6%	16.6%	0.010	0.07	0.941
Pre-treatment usage (May-Oct 2020)	Average kW	0.90	0.92	0.019	-0.87	0.384
	Percentile (0-100)	29.08	29.35	0.797	-0.34	0.734
	Load Factor	0.12	0.13	0.002	-0.77	0.444
	kWh hour ending 1	1.17	1.21	0.026	-1.27	0.203
	kWh hour ending 2	1.02	1.05	0.023	-1.17	0.242
	kWh hour ending 3	0.90	0.93	0.020	-1.57	0.116
	kWh hour ending 4	0.80	0.83	0.017	-1.73	0.084
	kWh hour ending 5	0.74	0.77	0.015	-1.64	0.102
	kWh hour ending 6	0.73	0.74	0.015	-0.80	0.422
	kWh hour ending 7	0.73	0.74	0.015	-0.65	0.516
	kWh hour ending 8	0.71	0.70	0.015	0.42	0.673
	kWh hour ending 9	0.58	0.58	0.020	-0.13	0.894
	kWh hour ending 10	0.37	0.39	0.029	-0.52	0.603
	kWh hour ending 11	0.19	0.19	0.038	-0.12	0.908
	kWh hour ending 12	0.10	0.10	0.046	0.06	0.951

Category	Variable	Treat (N=2,658)	Control (N=2,658)	Std. Error of the diff	t or z stat	p-val
	kWh hour ending 13	0.12	0.13	0.050	-0.12	0.903
	kWh hour ending 14	0.21	0.23	0.051	-0.38	0.702
	kWh hour ending 15	0.41	0.44	0.049	-0.68	0.497
	kWh hour ending 16	0.71	0.71	0.045	-0.10	0.923
	kWh hour ending 17	1.05	1.07	0.039	-0.37	0.713
	kWh hour ending 18	1.45	1.48	0.033	-0.75	0.451
	kWh hour ending 19	1.73	1.76	0.030	-0.75	0.455
	kWh hour ending 20	1.83	1.83	0.029	0.01	0.993
	kWh hour ending 21	1.78	1.80	0.028	-0.69	0.490
	kWh hour ending 22	1.67	1.71	0.027	-1.33	0.183
	kWh hour ending 23	1.47	1.48	0.024	-0.46	0.646
	kWh hour ending 24	1.24	1.27	0.023	-1.43	0.151
	Monthly usage 2020-05	458.59	472.58	14.617	-0.96	0.339
	Monthly usage 2020-06	586.72	600.21	16.546	-0.82	0.415
	Monthly usage 2020-07	695.97	708.40	18.208	-0.68	0.495
	Monthly usage 2020-08	912.56	929.64	17.588	-0.97	0.332
	Monthly usage 2020-09	733.70	740.85	13.334	-0.54	0.592
	Monthly usage 2020-10	605.52	613.44	11.320	-0.70	0.484
Location	Bay Area Inland	17.9%	18.0%	0.011	-0.14	0.886
	Central Valley Middle	12.3%	13.2%	0.009	-0.95	0.344
	Central Valley North	2.1%	1.9%	0.004	0.59	0.556
	Central Valley South	13.8%	14.0%	0.009	-0.16	0.874
	North Bay	4.8%	4.4%	0.006	0.72	0.470
	Other	0.8%	0.8%	0.002	-0.16	0.875
	Peninsula	3.7%	4.0%	0.005	-0.43	0.668
	San Francisco - Oakland	3.0%	3.6%	0.005	-1.07	0.283
	Sierras	7.7%	6.6%	0.007	1.49	0.136
	South Bay	32.1%	31.6%	0.013	0.38	0.702
	South Coast	1.8%	2.0%	0.004	-0.61	0.545

APPENDIX D: CHANGE IN THERMOSTAT SETTINGS

The three different thermostat brands manage the thermostat setpoints in order to deliver demand reductions. The following plots illustrate some of the differences in how the devices operated. Ecobee and Emerson devices record both thermostat cooling setpoint and internal temperature, while the Nest devices recorded only the thermostat cooling setpoint. Because DR events were intentionally called at different start times and for different duration, the illustrative examples shown are from the September 7, 2021 – the hottest four-hour duration event. The main observations are:

- Customers have a wide range of cooling setpoints.
- The ambient temperature is generally below the cooling setpoint throughout the day
- Ecobee devices engage in pre-cooling for one hour. After accounting for the pre-cooling, the thermostat cooling point is set back 4 degrees (F).
- Emerson devices pre-cool most of the day. They also had fewer devices and, thus, noisier results.
- Nest devices pre-cool for two hours and have the largest swing in the change of the cooling set point.

Figure 25: Distribution of Temperature Setpoints by Hour of Day and Device Brand (Controls)

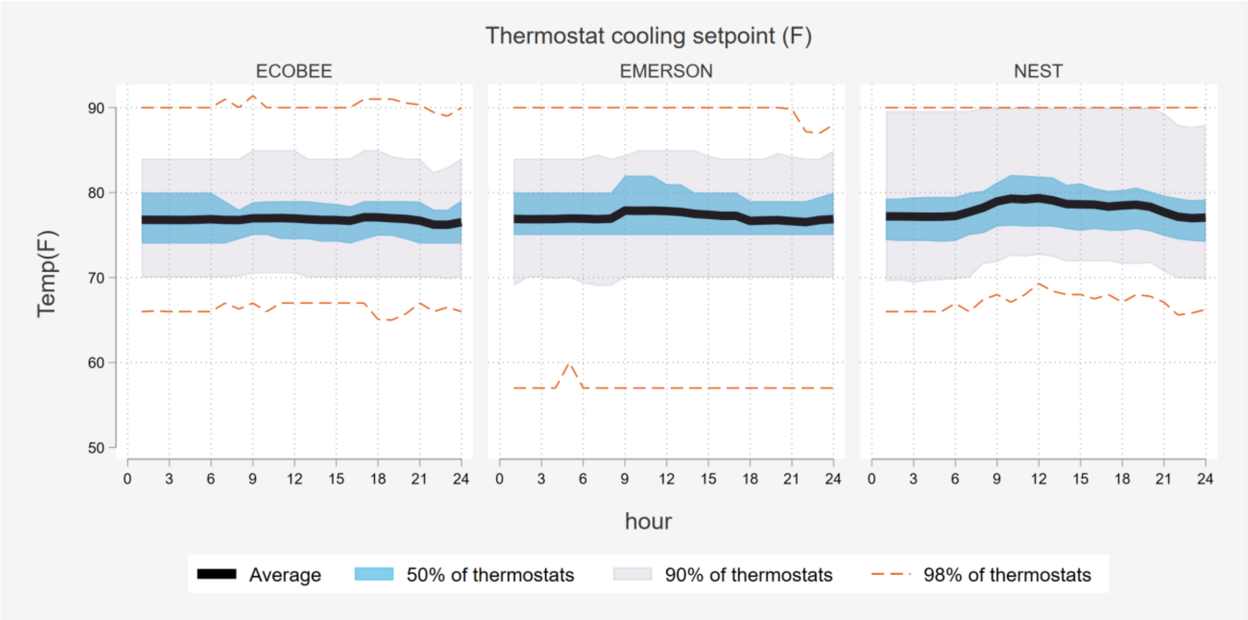


Figure 26: Distribution of Indoor Temperature by Hour of Day and Device Brand (Controls)

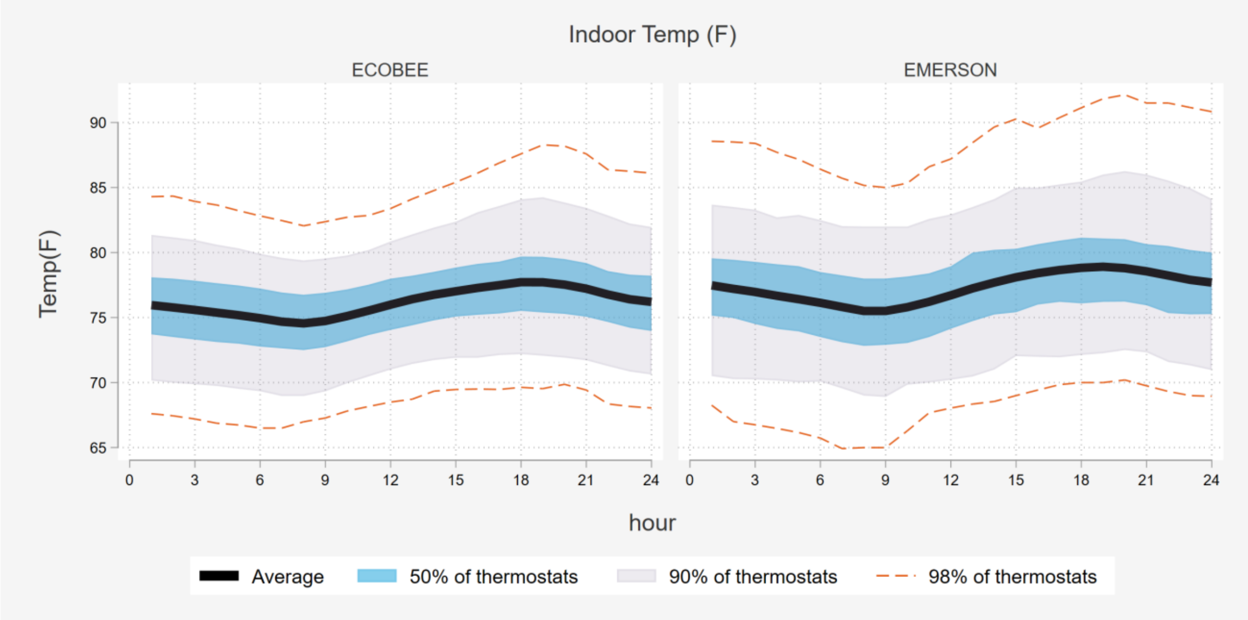


Figure 27: Change in Average Temperature Setpoint (Treatment versus Control)