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FINAL REPORT

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2023 Load Impact Evaluation for San Diego Gas and Electric's Small Commercial and Agricultural Critical Peak Pricing and Commercial Technology Deployment Program

Prepared for SD&GE
By Demand Side Analytics, LLC
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ABSTRACT

This study quantifies the demand impacts of three related interventions – time of use pricing with a critical peak pricing component, the shift in a time of use pricing window, and remote setback of commercial thermostats. The study focuses on three primary research questions: What were the 2023 demand reductions due to dispatch operations? Are customers delivering non-dispatchable demand reductions due to the interventions? What is the magnitude of dispatchable load reduction capability for 1-in-2 and 1-in-10 weather planning conditions?

SDG&E transitioned the full population of approximately 120,000 small business and agricultural customers from rates that did not vary by time of day to time varying rates in 2016. As part of the transition, in 2017 and part of 2018, SDG&E offered customers smart thermostats, free of charge, to help them manage their energy bills and automate response to critical peak prices. After the transition was complete the program was transitioned to a rebate model and split by customers on dispatchable rates (Peak Shift at Work (PSW) and Critical Peak Pricing – Default (CPP-D) for medium commercial and Industrial customers) versus those that aren't (AC Saver Day Ahead (ACSDA)). Dispatchable demand reductions were analyzed separately from non-dispatchable energy savings and demand reductions. In 2023, one event was called for Small CPP, Peak Shift at Work, and Critical Peak Pricing – Default and no events were called for AC Saver Day Ahead. During this event the Technology Deployment program on CPP rates (CPPTD) delivered 0.09 MW of load reduction and the Small CPP program delivered 0.29 MW of load reduction. The CPP-D event delivered 0.05 MW of load reduction. In PY2023, CPP events were called from 4 to 9 pm to align with resource adequacy hours.

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1 EXECUTIVE SUMMARY

Between November 2015 and April 2016, SDG&E defaulted over 120,000 small business customers from rates that did not vary by time of day onto time varying pricing with a critical peak pricing component (CPP-TOU). If these customers did not want critical peak pricing, they had the option to elect a time-of-use rate (TOU) without a critical peak component. Approximately 95% of customer sites remained on TOU-CPP rate and 5% elected the TOU only option. In tandem, SDG&E also transitioned small agricultural customers from rates that did not vary by time of day onto default time of use rates. A CPP-TOU rate was offered to customers on a voluntary (opt-in) basis. By April 2016, electricity rates without a time varying component were no longer available for small commercial and agricultural customers. Leading up to and after the rate transition, SDG&E offered customers smart thermostats, free of charge, to help them manage their energy bills and automate response to critical peak prices. This commercial thermostat program has now transitioned to a rebate model and has been separated into two program types: one for sites on dispatchable (CPP) rates and ones that are not.

The study analyzes two primary research questions:

- What were the 2023 demand reductions due to dispatch operations?
- What is the magnitude of dispatchable load reduction capability for 1-in-2 and 1-in-10 weather planning conditions?[1]

Table 1-1 summarizes the estimated ex-post load impact estimates for each of the interventions and distinguishes between dispatchable and non-dispatchable resources.

Table 1-1: Summary of 2023 Average Weekday Event Ex Post Load Impact Estimates[2]

Technology Intervention	Sites	Load without DR (MW)	Load reduction (MW)	% Reduction
Small TOU-CPP* (4-9 pm events)	23,445	57.48	0.29	0.5%
Tech Deployment: CPP rates (4-9 pm events)	113	0.74	0.09	12.6%

*Includes 73 Agricultural sites. Reductions overall and by rate class not statistically significant
**No events called for or for AC Saver Day Ahead (Technology Deployment customers not on CPP rates)

Table 2 summarizes the small CPP and commercial thermostat dispatchable ex ante reductions under August monthly peaking conditions for a 1-in-2 weather year. The results are shown under both CAISO

[1] Since no events were called for ACSDA in PY 2023, historical impacts from PY 2020 were used to estimate ex ante demand reductions.
[2] The average weekday event results are equal to the results of the August 29th event as that was the only event in PY 2023 for all programs.

and SDG&E peaking conditions and reflect the reduction capability from 4-9 pm, which aligns with resource adequacy requirements. For small CPP, the dispatchable reductions decrease due to projected decreases in enrollment due to CCA transition. The Community Choice Aggregator transition reduced the population by over 50% in PY 2022 and is further expected to reduce the Small CPP population by an additional 50% by 2025. Customers that shift from CPP rates to a CCA can no longer be on SDG&E CPP rates, so these sites with smart thermostats that were on CPP rates were migrated off of the CPP technology deployment program and retained for emergency dispatch[3]. They are no longer part of the Technology Deployment evaluation. Over time, customers are expected to sort themselves between TOU-CPP and TOU rates. Despite new installations projected for commercial thermostats, ex ante impacts for commercial thermostats are also expected to decrease given that thermostat connection rates decline over time faster than new thermostats are projected to be added.

Beginning in PY 2022 the CPP event window moved from 2pm to 6pm to 4pm to 9pm. As such, Small CPP and commercial thermostat customers on CPP rates are dispatched during the new 4 to 9pm event window. There were five CPP events in PY 2022, and PY 2022 impacts were used along with PY 2023 impacts for CPP and CPPTD ex ante estimates. Impacts from PY 2020, the most recent year with ACSDA events, combined with current enrollment assumptions, were used to estimate ex ante demand reductions for ACSDA.

Table 1-2: Summary of Ex ante Dispatchable Demand Reductions

Year	Small CPP*			Tech Deployment: CPP rates			Tech Deployment: ACSDA		
	Sites	MW (CAISO)	MW (SDG&E)	Sites	MW (CAISO)	MW (SDG&E)	Sites	MW (CAISO)	MW (SDG&E)
2023	23,443	0.58	0.58	116	0.08	0.06	374	0.24	0.24
2024	17,368	0.43	0.43	112	0.07	0.06	347	0.21	0.21
2025	13,529	0.34	0.34	105	0.06	0.05	310	0.17	0.18
2026	13,161	0.33	0.33	99	0.06	0.05	277	0.15	0.15
2027	13,210	0.33	0.33	94	0.05	0.04	247	0.12	0.12
2028	13,256	0.33	0.33	89	0.04	0.04	220	0.10	0.10
2029	13,299	0.33	0.33	84	0.04	0.03	197	0.08	0.08
2030	13,339	0.33	0.33	82	0.04	0.03	189	0.08	0.08
2031	13,375	0.33	0.33	82	0.03	0.03	189	0.07	0.07
2032	13,411	0.33	0.33	82	0.03	0.03	189	0.07	0.07
2033	13,446	0.33	0.33	82	0.03	0.03	189	0.06	0.06
2034	13,458	0.34	0.33	82	0.03	0.02	189	0.06	0.06

*Includes small commercial and small agricultural sites

[3] Rather than migrate them to ACSDA which tends to be called more often than CPP, including for non-emergency events.

2 INTRODUCTION

Most small business (SMB) customers across the U.S. have the same energy price throughout the day and do not have an incentive to consider the timing of their energy consumption and the degree to which consumption during peak hours drives energy and infrastructure costs. Between November 2015 and April 2016, SDG&E transitioned over 120,000 small business customers onto time of use rates with a critical peak component (CPP-TOU). While customers were defaulted onto TOU-CPP rates, they could elect to opt-out to a time-of-use (TOU) rate and 5% of them did. In tandem, SDG&E also transitioned small agricultural customers from flat rates onto time of use rates and offered a CPP-TOU rate on a voluntary (opt-in) basis. By April 2016, electricity rates without a time varying component were no longer available for small commercial and agricultural customers. In the years leading up to and after the rate transition, SDG&E offered customers smart thermostats, free of charge, to help them manage their energy bills and automate response to critical peak prices.

The transition to time varying rates encourages customers to consider when they consume power in addition to how much they consume. Customers can save by modifying when they use energy and by reducing energy use. The rates also better align the prices customers face and with the cost of supplying power. Prior to the transition, SDG&E implemented an outreach and education campaign designed to increase awareness and improve understanding of the new rate.

2.1 RATE AND TECHNOLOGIES EVALUATED

Two related but distinct interventions were assessed as part of the evaluation:

- CPP-TOU – Critical peak prices are designed to incentivize customers to reduce or shift electricity use from peak hours on a handful of days that drive the need for building additional power infrastructure. Customers receive rate reductions during summer non-event days to offset the higher prices during critical peak events (less than 1% of hours). At SDG&E, the CPP rates are layered on top of TOU rates. Historically, the event window was 11am to 6pm, then was shortened to 2pm to 6pm in PY 2018, and beginning in PY 2022 the window was shifted to 4 to 9 pm to align with resource adequacy hours.

- Smart thermostats – Through 2017, customers undergoing the transition to time varying rates were eligible for free ecobee thermostats to help automated price response during critical peak periods. The thermostats also can help reduce electricity consumption when a business is unoccupied. After the 2017 event season the program was shifted to a rebate design and expanded to allow additional

thermostat models.[4] There are four Technology Deployment programs of which some variants have been in operation since 2014[5]. Prior to 2017, smart thermostat/technology deployment customers were not required to be on a CPP rate, customers on TOU only rates are in the AC Saver Day Ahead (ACSDA) programs—one for non-residential customers and one for quasi-residential customers. Historically, all thermostats were dispatched from 2 to 6pm on CPP event days. Beginning in 2018, ACSDA events were called separately and did not necessarily overlap with CPP event days. ACSDA thermostats can be dispatched at any time between 12 pm to 9 pm (on-peak hours) for a maximum of 4 consecutive hours. Since PY 2022, Technology Deployment customers on CPP rates (CPPTD) thermostats have been dispatched from 4-9pm on CPP event days. The two rate-based programs are Peak Shift at Work (PSW, for small commercial customers) and CPP-D (for medium and large commercial customers). Smart thermostats enable curtailment by raising the thermostat temperature set point 4 degrees during the event window.

Both the CPP-TOU and TOU rates provide customers an incentive to reduce or shift electricity use away from peak hours. The CPP-TOU rates include higher prices during critical peak events, an event adder, which is applicable to usage during critical peak events which can be called between the hours of 4 pm and 9 pm during the summer.

2.2 STUDY RESEARCH QUESTIONS

Table 2-1 summarizes the key research questions for each intervention. Both CPP-TOU and commercial thermostats are dispatchable resources that also can lead to daily changes in energy use. Because dispatchable resources are used for operations, the impacts associated with event dispatch are estimated and reported separately from daily, non-dispatchable changes in energy use.

Table 2-1: Key Research Questions

	Research Question
1	What were the demand reductions due to program operations and interventions in 2023 – for each event day and hour?
2	How do load impacts differ for customers who have enabling technology and/or are dually enrolled in other programs?

[4] SDG&E had a limited number of free thermostats available in 2018 that were provided on first serve basis, the remainder of the 2018 thermostats were purchased by the customer and rebates were issued.
[5] They were expanded from the former Small Customer Technology Deployment (SCTD) program.

	Research Question
3	How does weather influence the magnitude of demand response?
4	How do load impacts vary for different customer sizes, locations, and customer segments?
5	What is the ex ante load reduction capability for 1-in-2 and 1-in-10 weather conditions? And how well does it align with ex post results and prior ex ante forecasts?
6	What concrete steps or experimental tests can be undertaken to improve program performance?

2.3 OVERVIEW OF METHODS

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 introduction of time varying rates or smart learning thermostats cause a change in critical peak period demand? Or can the differences be explained by other factors? To estimate energy savings, it is necessary to estimate what energy consumption would have been in the absence of the intervention—the counterfactual or reference load.

The change in energy use patterns was estimated using difference-in-differences with a control site matched to each participant. Key modeling design components are as follows:

- **Matched control tournament:** To identify the control pool sites that best matched each participant's energy use patterns on event-like proxy days (similar in weather and system conditions to event days), several matching methods were tested. These methods included different matching algorithms (e.g. Euclidean and propensity matching) and different site characteristics to be used in the matching. Matching methods included different combinations of proxy day load characteristics such as load factor, load shape, and site weather sensitivity. Control candidates were also "hard-matched" on climate zone, net metering status, and size.
- **Difference in-differences model with event and non-event days and participants and matched controls:** The data was structured with participant and control group loads on event- and non-event days side by side. Per site load impacts were estimated with difference-in-differences to net out exogenous differences between treatment and control that existed prior to the intervention. This approach was used as the primary method for

event impacts for critical peak events delivered by Small CPP participants and Technology Deployment program participants[6].

Figure 2-1 summarizes the out of sample testing process used to select the matched controls to be used for modeling. Essentially, the out of sample process is an iterative approach whereby data is systematically left out of the matching model then used to assess matching method performance—a well performing model should produce matches for loads on days which were not used for the model. The final model is identified based on least bias (% Bias) and best fit (Relative RMSE) metrics.

Figure 2-1: Out of Sample Process for Control Group Selection

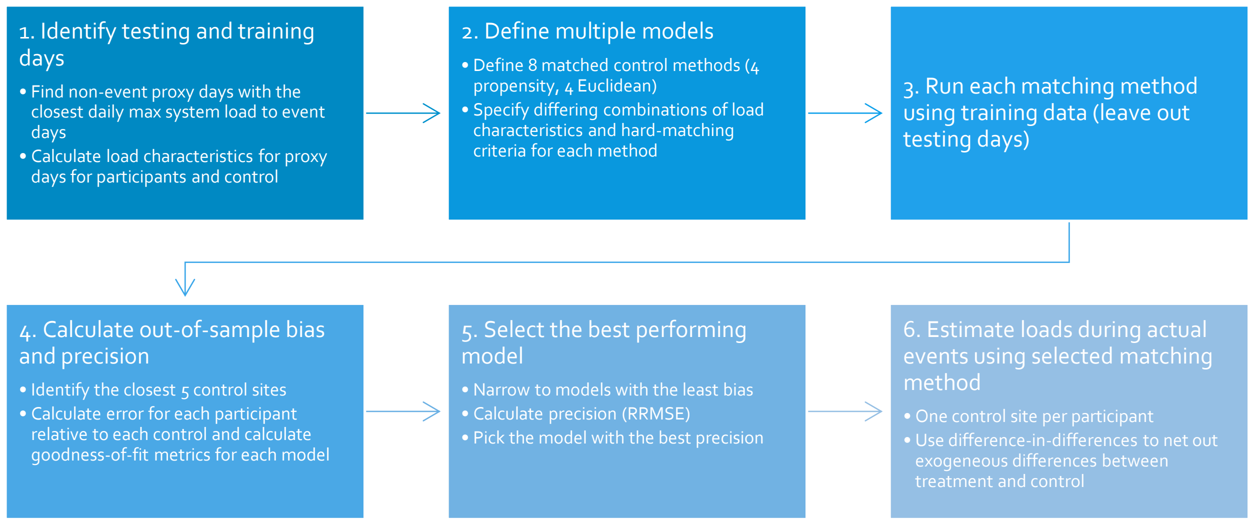


Figure 2-2 below demonstrates the mechanics of a difference in difference calculation. In the first panel, average observed loads on proxy days are shown for participants and for their matched controls. The difference between these two is the first "difference" and quantifies underlying differences between participants and their controls not attributable to event participation. Note that this first difference is very small, indicative of a high-quality match and sufficient sample size to neutralize the noise inherent in individual customer loads. The second panel shows the average observed participant and matched control loads on event days. The gap between these two is the second difference which includes both the difference due to event participation as well as the underlying first difference observable on non-event days. The third panel shows the average event day loads after netting out the proxy day difference from the event day control load. The result is the difference in difference impact.

[6] Due to the very small sample size, a panel regression model was used for Small CPP Agricultural participants.

Figure 2-2: Difference-in-Differences Calculation

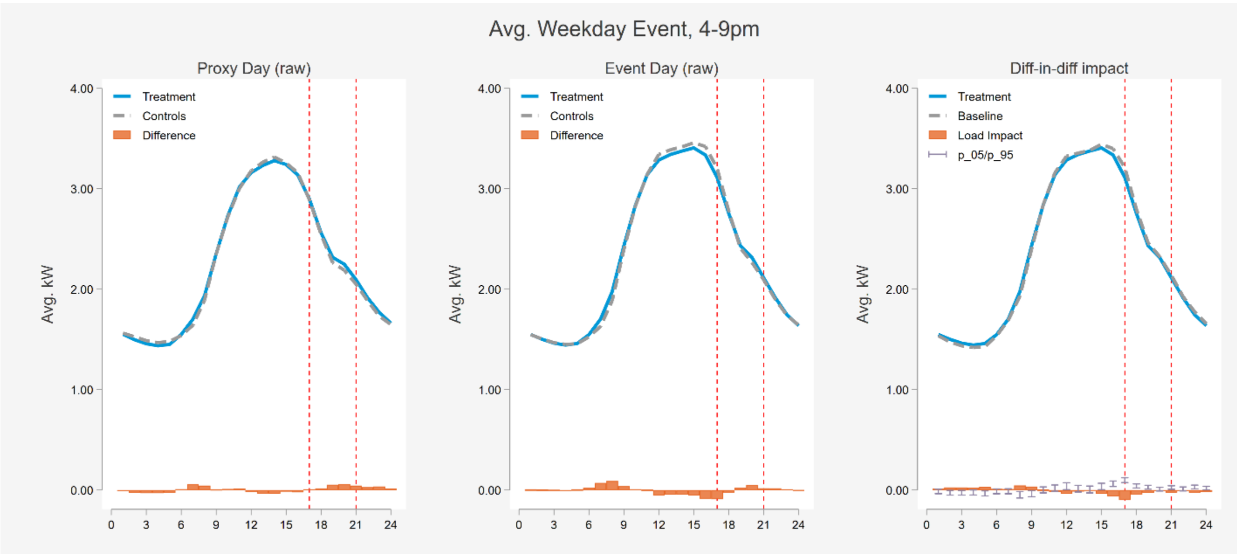


Table 2-2 summarizes the data sources, segmentation, and estimation methods used for each program. The segmentation was defined in advance of the analysis and is of particular importance because the evaluation used a bottom-up approach to estimate impacts and to ensure that aggregate impacts across segments equaled the sum of the parts. Because impacts for each segment were added together, the segmentation was structured to be mutually exclusive and completely exhaustive. In other words, every customer was assigned to exactly one segment. By design, the segmentation differentiated customers who were expected to deliver demand reductions– such as customers who sign up for event notification or technology to automate response – from customers who were expected to deliver little or no demand reductions. Additional segments were analyzed, after the fact, as part of exploratory analysis, but the core results presented are based on the segmentation detailed below. The segmentation categories for Small CPP were simplified in PY 2021 relative to previous years, and the same segmentation was continued in PY2023.

Table 2-2: Evaluation Methods

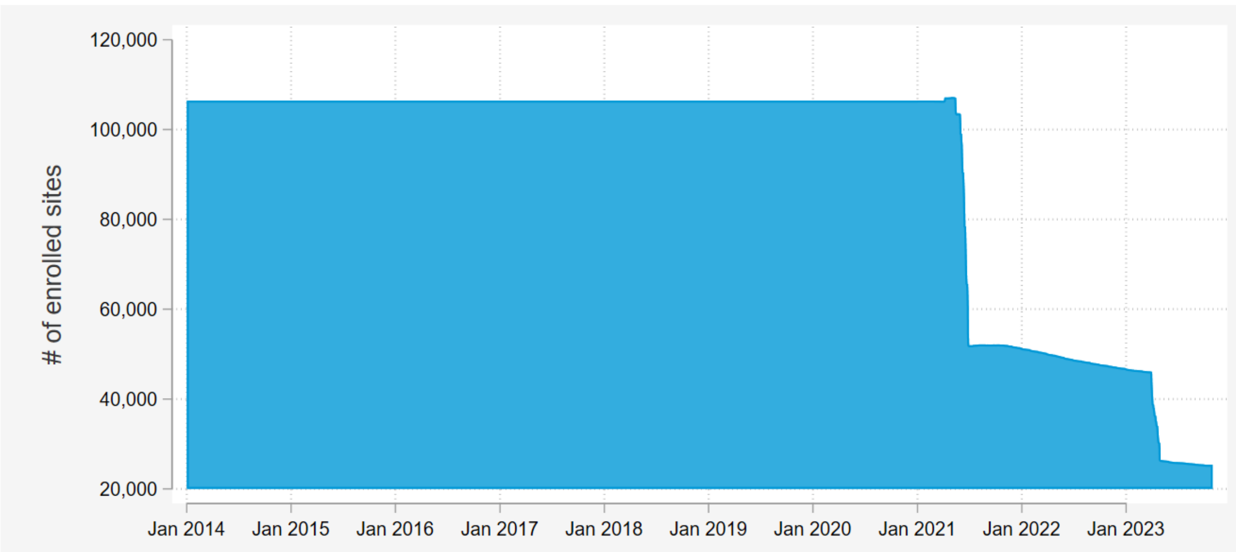
	CPP-TOU	TD Programs
Data sources / samples	▪ All event season data for up to the past three program years (2021-2023) for: ✓ ~23k Small Commercial participants ✓ ~5k CPP-TOU opt outs (to be used for match control group) ✓ ~70 Ag participants ✓ ~900 Ag opt-outs (to be used for match control group)	▪ All event season data for up to the past three program years (2020-2022) for: ✓ ~3.3k CPP-TD and Non-residential ACSDA participants ✓ ~10,800 residential customers – to serve as a control group which was pre-defined in 2019 analysis

<table>
<tr><th></th><th>CPP-TOU</th><th>TD Programs</th></tr>
<tr><td>Segmentation</td><td>Rate
✓ Small Commercial vs Ag
Enrollment in event notification (Y/N)
Climate zone (Coastal vs Inland)
Dual enrollment</td><td>Rate
✓ CPP-TD: PSW (Small) vs CPP-D (Med & Large)
✓ ACSDA: Small vs Med vs Large vs Quasi-residential
Climate zone (Coastal vs Inland)</td></tr>
<tr><td>Estimation method: Ex-post</td><td>Commercial and Agricultural: Difference-in-differences with matched controls</td><td>CPPTD: Difference-in-differences with matched controls
ACSDA: N/A</td></tr>
<tr><td>Estimation method: Ex-ante</td><td>Weather normalized customer regressions by segment for reference loads</td><td>Weather normalized customer regressions by segment for reference loads
Regression of historical event percent impacts versus weather for percent reductions
ACSDA: used 2020 impacts</td></tr>
</table>

3 CRITICAL PEAK PRICING EVENT DAY IMPACTS

SDG&E defaulted over 120,000 small customer sites onto CPP-TOU rates between November 2015 and April 2016. In 2021, many Small CPP customers switched to receiving their energy from a Community Choice Aggregator, which made them unable to participate in the Small CPP program. Since the large wave of unenrollment in 2021, participant counts have fallen further, from around 44,000 participants in 2022 to 23,000 participants in 2023.

Figure 3-1: Small Non-Residential Critical Peak Pricing Enrollment



The first event season for CPP was in 2016, but only one CPP event was called that year. It was called on SDG&E's peak day, Monday, September 27th. The PY 2016 evaluation for small customers found that the ex post load impacts for this lone CPP event were not statistically significant. The event was atypical. SDG&E had a low notification rate at the time – less than 25% of customers had elected to provide contact information to SDG&E –notifications were sent the Friday prior to the Monday event, and the event occurred near the end of the summer season. Though the participant population has dropped substantially in recent years the share of enrolled sites electing to receive event notification has increased substantially, with over 98% of enrolled sites electing to receive notifications. However, this is largely due to disenrollments of participants not receiving notifications rather than an increase in the number of participants receiving notifications.

In PY2020, there were nine CPP events in August through October. In PY2021, there were no CPP events. In PY2022, there were five CPP events all called within one week in September. In PY2023, there was only one CPP event called in August. The SDG&E system peaked on August 28, but there were no commercial TD events on the system peak day.

3.1 PARTICIPANT AND EVENT CHARACTERISTICS

Small CPP (Commercial and Agricultural) event impacts were assessed by site (premise and service point combination). Sites were grouped together into segments to assess potential differences in impacts for various groups. The segmentation, summarized in Table 3-1, was developed based on rate class, program, and technology characteristics which may influence impacts. Analysis was performed at the segment level so these granular impacts could therefore be summed, yielding aggregate impacts in addition to the segment specific impacts. Customers on CPP rates and in the TD program are covered in Section 4. Dually enrolled customers, those in the Small CPP program and either Summer Saver or CBP, were omitted from the analysis.

The segmentation criteria were defined as follows:

- **Rate class:** what type of rate was the site on throughout the study period?
- **Notification:** did the customer associated with the site receive any event notifications for any site?
- **Climate zone:** in which SDG&E climate zone was the site located?

Table 3-1: Small Critical Peak Pricing Population Segments

Rate class	Climate zone	Notification	Total Sites	Sites in analysis
Small Commercial	Coastal	No	930	928
		Yes	14,513	14,509
	Inland	No	520	520
		Yes	7,409	7,402
Small Agricultural	All	All	73	73
Total sites			23,445	23,432

Table 3-1 summarizes the total number of sites in each segment and the final number of sites used for analysis once data cleaning was completed[7]. For most segments, the vast majority of sites were included in the analysis. Due to the small population of the Small Agricultural program, the program was not further segmented. Aggregate ex post analysis results were scaled up to match the total number of sites before data cleaning.

[7] The cleaning algorithm ensured that complete data was available for the study period. Sites for which high quality matches could not be found were also excluded.

Table 3-2 shows PY2023 CPP event day, as well as the maximum daily temperature weighted by participating sites. This event occurred on August 29. The SDG&E system peak occurred on August 28, 2023.

Table 3-2: Small Critical Peak Pricing Events in 2023

Event day	Day of week	Event start	Event end	Max daily temp (F)	SDG&E system load (MW)
8/29/2023	Tuesday	4:00 PM	9:00 PM	93.7	4,375

3.2 DATA SOURCES AND ANALYSIS METHOD

Table 3-3 summarizes the five data sources used to conduct the Small CPP analysis. The analysis was done by site on hourly load data. Various data sources were used to classify sites into the study segments. While different segments were developed for the various analyses in this report (rate versus technology based, event and non-event), the characteristic definitions used to build segments were consistent across analyses.

Table 3-3: Small Critical Peak Pricing Evaluation Data Sources

Source	Comments
Hourly interval data	▪ Summer 2023 (June 1 through October 31) ▪ All analysis done by site (Premise ID x Service Point ID pair)
Outage information	▪ PSPS and CAISO emergency outage data details which customers and what timeframes were impacted by outages ▪ Outage days which affected participants or control sites were excluded from the analysis
Customer characteristics	▪ Treatment: All small non-residential (Commercial and Agricultural) CPP rates (23k sites) ▪ Control: CPP-TOU opt outs (5,000 Small Comm opt-outs and ~900 Ag opt-outs). CCA customers were excluded as eligible control candidates. ▪ Industry, zip codes, climate zone, NEM status used in matching model selection ▪ NEM status, climate zone, and DR program enrollment used for segmentation
SDG&E hourly system loads	▪ Summer 2023 (June 1 through October 31)

Source	Comments
	▪ Used to identify non-event high system load days
Ex post weather data by weather station	▪ Used to derive cooling degree days for impact evaluation modeling
Event notification	▪ List of notifications sent to each account for each event day ▪ Rolled up by customer to identify customers who had received notifications at any site (used in segmentation)

The primary analysis method was difference-in-differences with matched controls. The distance matching approach used selected one matched control site for each of the roughly 23,000 non-residential Small CPP sites among a matched control candidate pool of roughly 5,000 small commercial CPP opt-outs and 900 small agricultural CPP opt-outs. These customers were not enrolled in CPP or other DR programs which might influence energy use and excluded sites that were recently defaulted to a CCA. The difference-in-differences model was then used to assess impacts and standard errors for each event and each study segment.

3.3 EX POST LOAD IMPACTS

Load reductions are a function of the reference load. When there is lower load, demand response programs have less opportunity for reduction.

Table 3-4 summarizes the portfolio load reductions for all Small Commercial sites on CPP rates (and not dually enrolled in other DR programs) for August 29 event and 4 pm to 9 pm reductions. Small CPP Agricultural impacts are not accounted for in the table, but Agricultural customers make up less than one percent of Small CPP enrollees. The average weekday event aggregate load reduction was 0.29 MW across all 23,445 sites and the average reduction per site was 0.01 kW (shown in Table 3-4). Reductions were not statistically significant at the 95% level. In the tables, the orange bars show a visual comparison of the reductions that are numerically labeled on the left of the bars.

Table 3-4: Small CPP Program Specific Event Reductions

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions Aggregate (MW)	Reductions Average Site (kw)	Significant (90% CI)	Significant (95% CI)
8/29/2023	Avg. 4 to 9 pm	78.6	23,445	0.29	0.01	No	No
Avg Weekday	**Avg. 4 to 9 pm**	**78.6**	**23,445**	**0.29**	**0.01**	No	No

Reductions were also segmented by rate class, climate zone, and customers who signed up for event notifications[8]. Table 3-5 details the reference loads and load reductions overall and by each of these study segments[9] for the average 4 pm to 9 pm weekday CPP event. Both aggregate reductions and average reductions per site are shown. Small Commercial portfolio impacts for the average event were 0.24 MW in aggregate or 0.4% of whole building load, and Small Agricultural impacts for the average event were 0.05MW in aggregate or 7.1% of whole building load. Impacts during the August 29 event for both Small Commercial and Small Agricultural customers were not statistically significant.

Segmentation of load impacts shows minor differences in three of the commercial segments. Coastal customers regardless of notification and inland customers receiving notifications produced reductions of 0.5% to 1.6% of whole building load. The inland customers not receiving notification produced reductions which were small in magnitude and not statistically significant, though directionally slightly negative, implying an increase in load.

Program specific impacts for the 23,372 Small Commercial sites were 0.24 MW. Program reductions for the 73 Agricultural sites were positive but not statistically significant, with 0.05 MW of load reduction in aggregate.

[8] Sites were classified as receiving notifications if any site under the parent customer received notifications. There were multiple indirect channels where sites that did not directly sign up for notification could become aware of them. SDG&E publicized the events via mass media channels – radio and TV – and customers at many smaller sites that did not sign up for notification also had medium and large facilities that were signed for event notification.

[9] Results for more granular segments including NEM status and dual enrollment in other DR programs are included in the appendix.

Table 3-5: Small CPP Program Average Event Reductions by Segment

Subcategory	Temp	Sites	Aggregate (MW) Ref Load	Aggregate (MW) Reduction	Aggregate (MW) % Reduction	Aggregate (MW) Std Error	Average Site (kw) Ref Load	Average Site (kw) Reduction	Average Site (kw) Std Error	t-stat
Comm: Coastal & no notification	77.1	930	1.86	0.03	1.6%	0.04	2.00	0.03	0.05	0.67
Comm: Coastal & received notification	76.8	14,513	34.59	0.19	0.5%	0.21	2.38	0.01	0.01	0.89
Comm: Inland & no notification	82.4	520	1.06	0.00	-0.5%	0.03	2.03	-0.01	0.06	-0.15
Comm: Inland & received notification	82.1	7,409	19.25	0.02	0.1%	0.16	2.60	0.00	0.02	0.16
Agricultural portfolio	78.3	73	0.72	0.05	7.1%	0.19	9.93	0.70	2.59	0.27
Commercial portfolio	78.6	23,372	56.76	0.24	0.4%	0.27	2.43	0.01	0.01	0.88
All study segments	78.6	23,445	57.48	0.29	0.5%	0.33	2.45	0.01	0.01	0.88

The load shape for the average event day for commercial and agricultural participants is summarized in greater detail in Figure 3-2 and Figure 3-3, respectively. The figures, extracted from the Ex Post Load Impact Table, are for the small CPP portfolio population. The figures show the aggregate hourly loads (actual and counterfactual) for these sites. The tables accompanying each figure show aggregate impacts for the 4 pm to 9 pm event window. Load was reduced by 0.4% (0.24 MW) during the average weekday event window for commercial sites and by 7.1% (0.05 MW) for agricultural sites. Program reductions appear the largest around 2pm-6pm for commercial sites, which suggests lingering behaviors from 2021 when the previous event window was from 2pm to 6pm.

Figure 3-2: Small CPP Commercial Program Specific Impacts

Table 1: Menu options

Type of results	Aggregate
Category	Rate class
Subcategory	Commercial
Event date	Avg Weekday 4-9pm

Table 2: Event day information

CPP Event start	4:00 PM
CPP Event end	9:00 PM
Total enrolled accounts	23,372
Avg load reduction Event Window	0.24
% Load reduction Event Window	0.4%

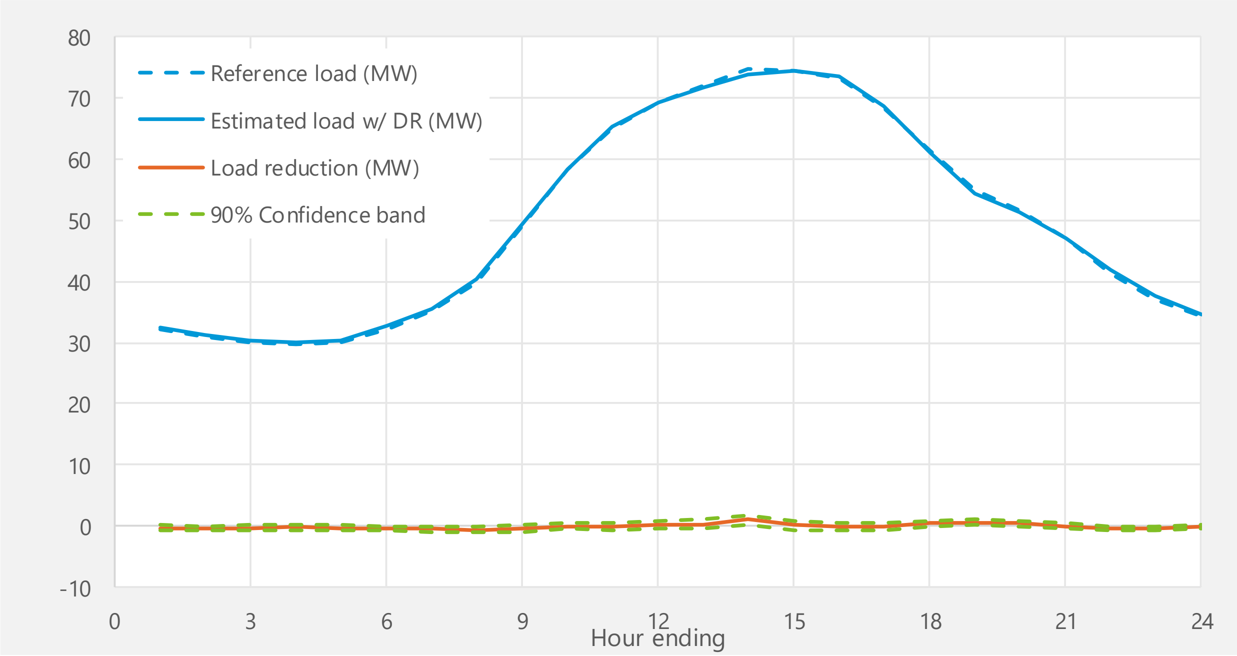


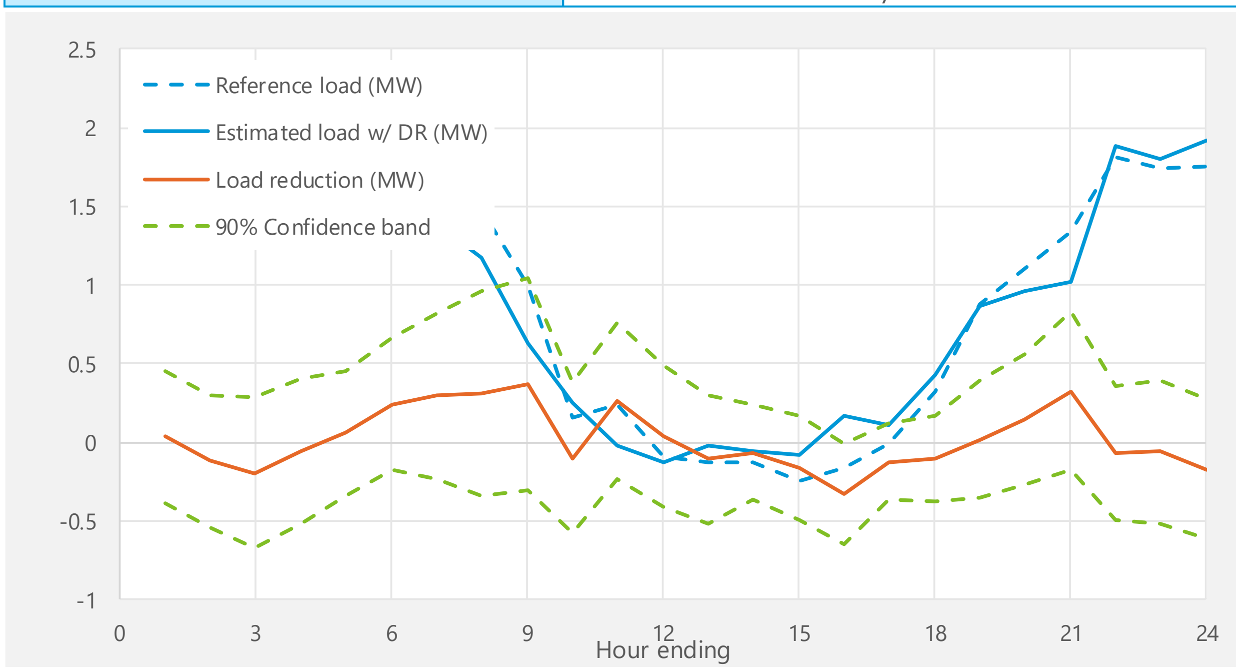
Figure 3-3: Small CPP Agricultural Program Specific Impacts

Table 1: Menu options

Type of results	Aggregate
Category	Rate class
Subcategory	Agricultural
Event date	Avg Weekday 4-9pm

Table 2: Event day information

CPP Event start	4:00 PM
CPP Event end	9:00 PM
Total enrolled accounts	73
Avg load reduction Event Window	0.05
% Load reduction Event Window	7.1%



3.4 EX ANTE LOAD IMPACTS

A key objective of the 2023 evaluation is to quantify the relationship between demand reductions, temperature and hour of day. Ex ante impacts are estimated load reductions as a function of weather conditions, time of day, and forecasted changes in enrollment. By design, they reflect planning conditions defined by normal (1-in-2) and extreme (1-in-10) peak demand weather conditions. The historical load patterns and performance during actual events are used to estimate the reductions for a standardized set of weather conditions.

At a fundamental level, the process of estimating ex ante impacts included five main steps:

1. Estimate the relationship between customer loads (absent DR) and weather
2. Use the models to predict customers loads (absent DR) for 1-in-2 and 1-in-10 weather year conditions
3. Apply the average percent reductions, at an hourly level, from historical events. The average reduction was employed because experience with small business default CPP is limited and there is less of a history of program performance across events.
4. Estimate reductions for 1-in-2 and 1-in-10 weather year conditions
5. Incorporate the enrollment forecast

3.4.1 Relationship of Customer Loads and Percent Reductions to Weather

Figure 3-4 summarizes the relationship between weather and CPP participant loads (excluding Ag) in 2023. Only days when CPP resources were not dispatched are included. The panel to the left shows average hourly loads for current participants for different temperature bins, defined by the daily maximum temperature. The panel to the right shows the relationship between daily maximum temperatures and hourly loads. The hottest temperature day in the right panel is the highest load curve. In 2023 we see the expected pattern that energy demand and discretionary load increases with hotter weather.

Figure 3-5 shows the relationship between aggregate small commercial CPP loads and SDG&E daily peak loads. Small Commercial CPP loads are highly correlated with system load daily peaks during the 4 to 9 pm resource adequacy window. However, small commercial loads peak around 3pm (HE 15) and drop sharply thereafter, leaving relatively little discretionary load to curtail after about 6pm (HE 18). This remains a challenge since the shift of the CPP window from 2 to 6pm to 4 to 9pm. Essentially, about half of small commercial load has dissipated by the time system peaks typically occur. Small CPP participants are therefore not in a strong position to provide reductions when resources are needed most.

Figure 3-4: Weather Sensitivity of Small Commercial CPP Loads

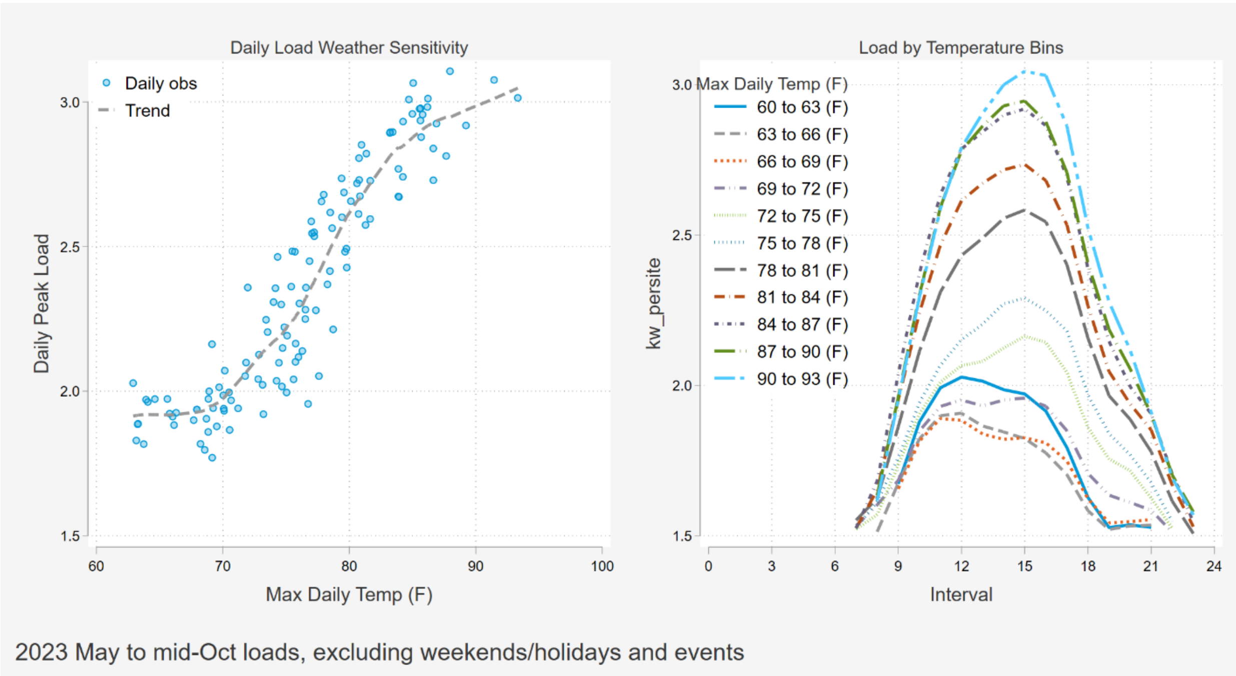
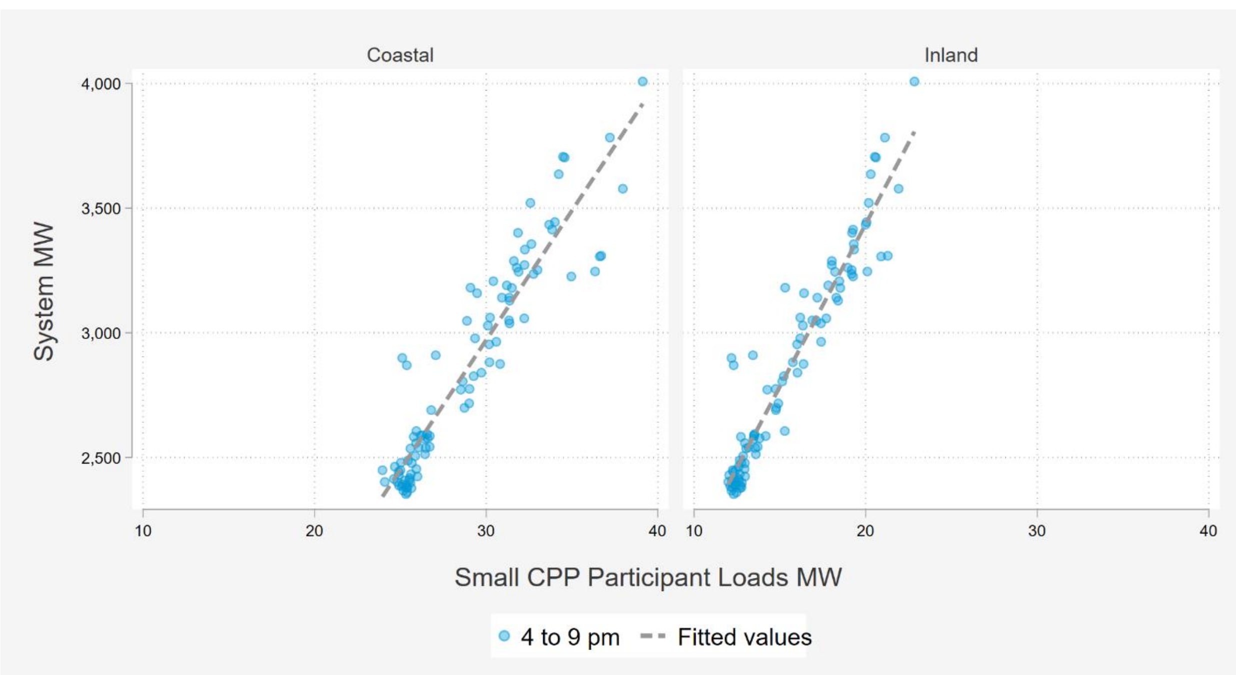
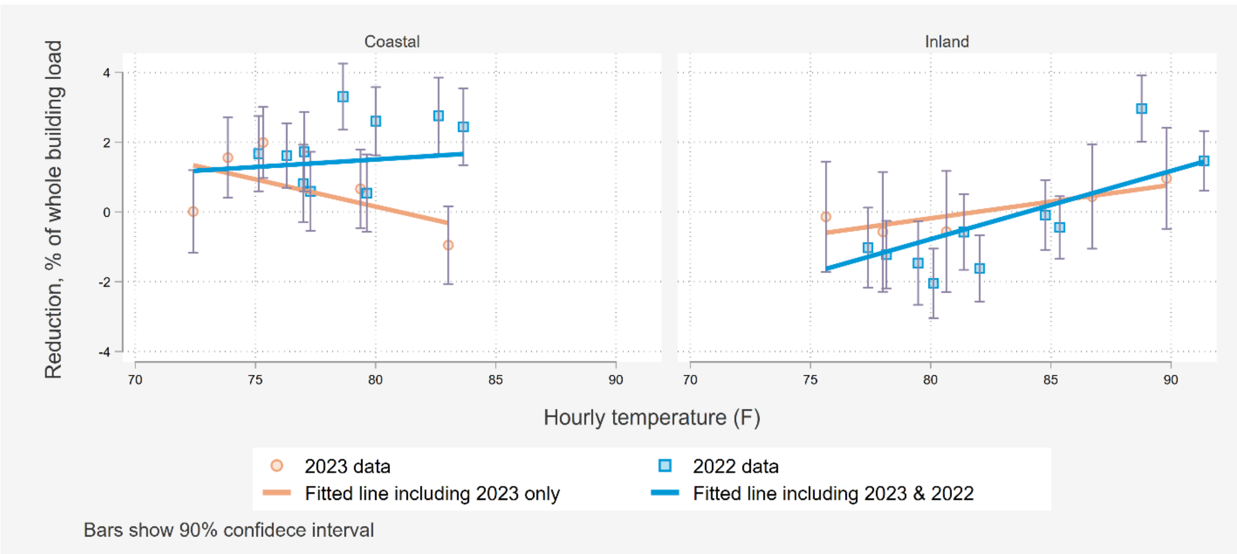


Figure 3-5: Small Commercial CPP Load versus System Daily Peaks



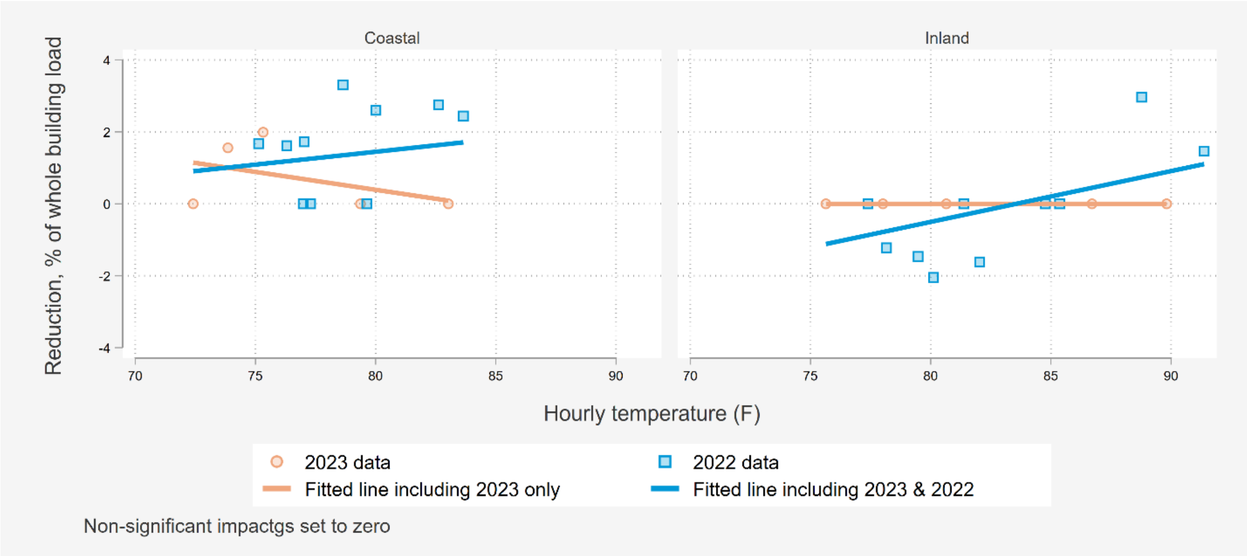
Because there was only a single CPP event in PY 2023, impacts for both PY 2022 and PY 2023 events were used to model ex ante impacts for PY 2023. Figure 3-6 shows hourly event percent reductions for these events as a function of hourly temperatures. The left panel shows coastal customers, and the right shows inland customers. Note that while Figure 3-6 shows that reductions are positive in magnitude for coastal customers and negative in magnitude for inland customers, most reductions are small and statistically insignificant. Using only event hours for the single PY2023 event (indicated in orange) there appears to be a slight negative trend between temperature and impacts However, impacts are largely not significant for these hours and there are too few observations to establish a trend. When adding in PY 2022 events (denoted in blue), this is somewhat reversed. A much stronger relationship was found between impacts in a given hour and which event hour it is (e.g. first hour, second, hour, etc.). When developing the ex ante impact model an event hour coefficient was included but a weather variable was not included. Regardless, Figure 3-6 underscores why it is important to also include data points from both PY 2022 and PY 2023.

Figure 3-6: Small Commercial CPP Hourly Reductions and Temperatures with Uncertainty



To further address the non-significant impacts, PY 2022 and PY 2023 ex post impacts which were not statistically significant were assumed to be zero for ex ante impact modeling purposes. Figure 3-7 shows the resulting impacts and trends.

Figure 3-7: Small Commercial CPP Hourly Reductions and Temperatures Used for Ex Ante



3.4.2 Ex Ante Load Impacts

Table 3-6 summarizes the ex ante demand reduction capability by forecast year and planning condition. The tables reflect dispatchable demand reductions available from 4 pm to 9 pm in August monthly peaking conditions for 1-in-2 and 1-in-10 weather conditions. They align with the planning conditions used for resource adequacy attribution. To avoid double counting, the table only includes resources that are not dually enrolled in other DR programs, known as portfolio impacts.

Table 3-6: Small CPP Portfolio Impacts for August Monthly Peak Day (4-9 pm)[10]

Year	Sites	CAISO (MW)		SDG&E (MW)	
		1-in-2	1-in-10	1-in-2	1-in-10
2023	23,443	0.58	0.62	0.58	0.65
2024	17,368	0.43	0.46	0.43	0.48
2025	13,529	0.34	0.36	0.34	0.37
2026	13,161	0.33	0.35	0.33	0.36
2027	13,210	0.33	0.35	0.33	0.36
2028	13,256	0.33	0.35	0.33	0.37
2029	13,299	0.33	0.35	0.33	0.37
2030	13,339	0.33	0.35	0.33	0.37
2031	13,375	0.33	0.35	0.33	0.37
2032	13,411	0.33	0.35	0.33	0.37

[10] Includes Small commercial and small agricultural sites.

Year	Sites	CAISO (MW)		SDG&E (MW)	
		1-in-2	1-in-10	1-in-2	1-in-10
2033	13,446	0.33	0.35	0.33	0.37
2034	13,458	0.34	0.35	0.33	0.37

The enrollment forecast was developed by SDG&E and shows a declining number of customers enrolled in small non-residential CPP. The steep drop in sites in 2025 is due to the expected defaulting of non-residential sites to a Community Choice Aggregation energy supplier. The expectation is that roughly half of current Small CPP participants will be served by the CCA starting by 2025. This transition will result in disenrollment from SDG&E's CPP rates, which precludes participation in SDG&E's CPP events. Note that participants served by CCAs will remain on SDG&E's distribution TOU rates. For ex ante impacts, reduction in enrollment forecasts are assumed to have a proportional effect on the magnitude of demand reduction resources. This assumption is conservative. In past implementations, less price responsive customers opted out of default CPP rates, leading to lower enrollment rates, but a limited effect on reduction capability.

3.4.3 COMPARISON OF EX POST AND EX ANTE LOAD IMPACTS

Table 3-7 compares the demand reductions from 2023 events to the reduction expected for the 1-in-2 weather conditions used for planning. Results are shown for the 4 to 9 pm resource adequacy window. In PY 2023, commercial and agricultural Small CPP customers delivered 0.29 MW during the dispatch period of 4 to 9 pm, about 17 percent of which is attributed to 73 agricultural customers. The expected load reduction capability for 2023 under SDG&E and CAISO 1-in-2 weather conditions is 0.58 MW, which is about 100 percent more than the ex post estimate. Note that 1-in-2 weather conditions include similar temperatures and reference loads as the 2023 event day, August 29. Ex ante impacts are higher than PY 2023 ex post because they also include observations from the multiple PY 2022 events. Ex ante impacts are similar across weather conditions because only the reference loads are assumed to vary by weather. Impacts do not have a high level of certainty, given their small magnitude on a percent reduction basis. Ex post results also reflect the unique hourly temperature profiles of each event, whereas ex ante impacts assume a fixed number of sites and weather for a single peak day.

Table 3-7: Small CPP Comparison of PY 2022 Ex Post and PY 2022 Ex Ante Load Impacts

Result Type	Day Type and Period	Sites	Load without DR (MW)	Load Reduction (MW)	% Reduction	Daily Max Temp (F)
Ex Post Avg. Weekday	Resource Adequacy Period (4 to 9pm)	23,445	57.48	0.29*	0.5%	91.9

Result Type	Day Type and Period	Sites	Load without DR (MW)	Load Reduction (MW)	% Reduction	Daily Max Temp (F)
Ex ante SDG&E	1-in-2 Weather August Peak (4 to 9pm)	23,443	57.24	0.58	1.0%	93.1
Ex ante CAISO	1-in-2 Weather August Peak (4 to 9pm)	23,443	56.26	0.58	1.0%	89.3

*PY 2023 Ex post impacts not statistically significant and were assumed to be zero for ex ante modeling purposes. PY 2023 ex ante modeling included PY 2022 and PY 2023 ex post impacts and also assumed non-significant impacts to be zero.

3.4.4 Ex Ante Load Impact Slice-of-Day Tables

Table 3-8 and Table 3-9 show the 2023 ex ante aggregate hourly impacts for each month under CAISO and SDG&E monthly peaking conditions, respectively. The load impacts in the table represent the sum of Small CPP Commercial and Small CPP Agricultural aggregate impacts (the latter being zero in all hours). The tables are designed to enable the CPUC's Slice-of-Day Resource Adequacy requirements. The estimated reductions are greatest in August and September as there is the most amount of cooling load available to be curtailed. Response to an event begins early in the day around 11am and peaks in the late afternoon when temperatures are typically the hottest. Most of the response occurs before the current event window and Resource Adequacy window. This is consistent with past evaluations which have consistently shown response to occur earlier in the day more in line with the past event windows of 11am to 6pm and more recently, 2pm to 6pm.

Table 3-8: Slice of Day Table for CAISO 1-in-2 Weather Year Monthly Peak Day (Aggregate Impacts (MW))

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.94	0.93	0.93	1.09	1.03	1.20	1.34	1.43	1.43	1.37	1.13	0.90
13	0.95	0.94	0.93	1.10	1.04	1.22	1.36	1.45	1.46	1.39	1.14	0.91
14	0.96	0.95	0.95	1.12	1.06	1.25	1.39	1.49	1.49	1.42	1.16	0.92
15	0.98	0.97	0.96	1.13	1.07	1.26	1.40	1.50	1.51	1.44	1.18	0.94
16	0.97	0.96	0.95	1.12	1.06	1.25	1.39	1.48	1.49	1.42	1.17	0.93
17	0.78	0.77	0.77	0.88	0.84	0.97	1.08	1.15	1.16	1.11	0.92	0.74
18	0.57	0.57	0.56	0.63	0.60	0.69	0.76	0.81	0.81	0.78	0.66	0.55
19	0.40	0.40	0.40	0.43	0.41	0.46	0.49	0.52	0.52	0.51	0.45	0.38
20	0.26	0.26	0.26	0.26	0.25	0.27	0.29	0.31	0.31	0.31	0.28	0.25
21	0.13	0.13	0.13	0.12	0.12	0.12	0.13	0.13	0.13	0.13	0.13	0.13
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Demand reductions are positive (Blue)
Load increases are negative (Orange)

Table 3-9: Slice of Day Table for SDG&E 1-in-2 Weather Year Monthly Peak Day (Aggregate Impacts (MW))

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.94	0.93	0.93	1.16	1.12	1.19	1.41	1.45	1.56	1.33	1.13	0.90
13	0.95	0.94	0.93	1.17	1.13	1.21	1.43	1.48	1.59	1.35	1.15	0.91
14	0.96	0.95	0.95	1.20	1.15	1.23	1.47	1.51	1.63	1.38	1.17	0.92
15	0.98	0.97	0.96	1.21	1.17	1.24	1.48	1.53	1.64	1.39	1.19	0.94
16	0.97	0.96	0.95	1.20	1.15	1.23	1.46	1.51	1.62	1.38	1.17	0.93
17	0.78	0.77	0.77	0.94	0.91	0.96	1.14	1.17	1.26	1.08	0.93	0.74
18	0.57	0.57	0.56	0.67	0.65	0.68	0.80	0.81	0.87	0.76	0.67	0.55
19	0.40	0.40	0.40	0.45	0.43	0.45	0.52	0.52	0.56	0.50	0.45	0.38
20	0.26	0.26	0.26	0.27	0.27	0.27	0.31	0.30	0.33	0.30	0.28	0.25
21	0.13	0.13	0.13	0.12	0.12	0.12	0.13	0.12	0.13	0.13	0.13	0.13
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Demand reductions are positive (Blue)
Load increases are negative (Orange)

4 COMMERCIAL THERMOSTAT EVENT DAY IMPACTS

Customers undergoing the transition to time varying rates were eligible for free ecobee thermostats to help automated price response during critical peak periods. The thermostats can also help reduce electricity consumption when a business is unoccupied. The program was known as the Small Commercial Technology Deployment (SCTD) and has been in operation since 2014. However, prior to 2017, customers were not required to be on a CPP rate and, as a result, SCTD also included participants who are enrolled in TOU only rates with no dispatchable component. Thermostats are dispatched from 4-9 pm and Technology Deployment events historically coincided with CPP events. In PY2023, one CPP event was called. No commercial ACSDA events were called.

In 2018, the program changed from a free thermostat to a rebate model and was broadened to include additional thermostat models. Figure 4-1 summarizes four the specific program designations for the PY 2023 evaluation. There are two programs (and accompanying rates) for customers on CPP-TOU rates: Peak Shift at Work (PSW) for Small non-residential customers and CPP-D for Medium and Large non-residential customers. Devices enrolled in these programs are dispatched during CPP events, of which there were two in PY 2023. For customers who are not on dispatchable rates, there are also two programs AC Saver Day Ahead (ACSDA) for non-residential customers and ACSDA for quasi-residential customers (who are on residential rates). There were no non-residential ACSDA events called in PY 2023. ACSDA events are typically called from 6 to 8 pm. ACSDA thermostats can be dispatched at any time between 12 pm to 9 pm (on-peak hours) for a maximum of 4 consecutive hours. For all four thermostat programs, devices are curtailed by raising the thermostat temperature set point 4 degrees during the event window.

Figure 4-1: Summary of TD Program Taxonomy

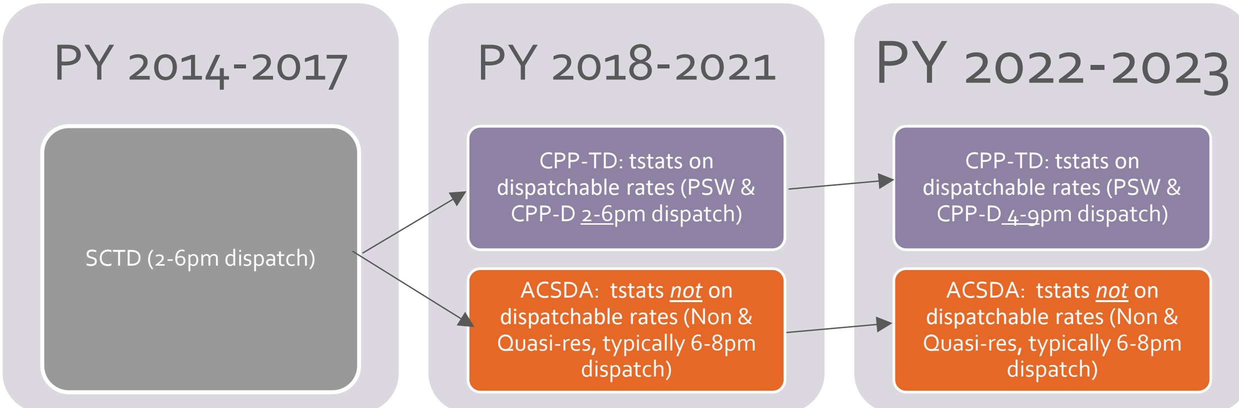


Table 4-1 shows the customer site counts and aggregate percent reduction for the previous three program years for each of the Commercial TD programs. The Community Choice Aggregator transition which began in PY 2022 reduced the population of participants on dispatchable rates. Customers that shift from CPP rates to a CCA can no longer be on SDG&E CPP rates, so these sites with smart thermostats that were on CPP rates were migrated off the CPP technology deployment program and retained for emergency dispatch[11]. They are no longer part of the Technology Deployment evaluation. A substantial number of inactive participants and thermostats on all four programs were also unenrolled before the PY 2023 events, resulting in population counts substantially below those of PY 2022.

Table 4-1: Historical Program Overview

	Count of Connected Sites (Aggregate Percent Reductions)			
Program	2020	2021	2022	2023
PSW	773 (7.0%)	253 (No Events)	172 (5.5%)	95 (11.4%)
CPP-D	431 (6.6%)	130 (No Events)	43 (6.7%)	20 (13.7%)
ACSDA Non-Residential	397 (3.0%)	661 (No Events)	402 (No Events)	347 (No Events)
ACSDA Quasi-Res	544 (1.5%)	15 (No Events)	13 (No Events)	10 (No Events)

There are 115 connected non-residential sites on dispatchable rates (small commercial on PSW and medium and large on CPP-D) and the remaining 357 connected sites are installed at non-residential and quasi-residential sites on non-dispatchable rates enrolled in AC Saver Day Ahead (ACSDA). As noted above, no events were called for sites on non-dispatchable rates (ACSDA). In PY 2023, reductions

[11] Rather than migrate them to ACSDA which tends to be called more often than CPP, including for non-emergency events

during the single called event were statistically significant for PSW. There were no weekend events called.

Device connectivity is a key driver of realized load impacts because only connected thermostats can receive dispatch signals and deliver load reductions. As such, connectivity has been closely monitored since PY 2018. In PY 2018 and PY 2019 roughly half of devices were not connected. However, much of this was due to the auto-enrollment of new accounts moving into a site with a previously enrolled thermostat. In practice the device is often no longer connected and simply ends up diluting results. In PY 2022 SDG&E began periodically removing thermostats inactive for more than 365 days from the dispatch portal. In PY 2023, this was shortened to 90 days to further improve cost effectiveness. In addition, a handful of sites with more than five thermostats were unenrolled from the program because the current implementation configuration does not allow for notification of event overrides for more than five devices per enrolled site. This had the effect of boosting overall thermostat connectivity rates but also of substantially lowering the number of enrolled devices. However, there is still a steady decline in connectivity over time and it is an important consideration for forecasting future impacts. Impacts continue to be derived at a per connected thermostat basis so they can be applied to enrollment forecasts reflecting numbers of connected devices in addition to enrolled sites. Future efforts to reconnect disconnected devices, particularly among programs or customer segments delivering greater reductions, could substantially increase future load reduction potential for the Technology Deployment programs.

4.1 TECHNOLOGY AND EVENT CHARACTERISTICS

The thermostats used as the enabling device receive a signal from SDG&E to curtail usage during events. For all PY2023 events, thermostats were controlled by raising the setpoint temperature by 4 degrees. This approach is intended to reduce energy usage by air conditioning units. However, to receive the curtailment signals, the devices must be connected to the internet and registered in the SDG&E dispatch portal. This is initially set up during the device installation process, but connectivity can be affected by internet reliability. Once connected, the device can receive and execute curtailment signals, and it can also communicate event notifications to users before the beginning of an event. Participating, connected devices were sent event notifications 24 hours prior to an event.

The PY2019 evaluation highlighted the issue of disconnected devices and the dampening effect this had on average "per-site" and "per-device" impacts. The failure rate described in the past incorporated two threads of failure-site attrition and thermostat failure. Site attrition occurs when a site, or customer, un-enrolls from a program or moves outside of the service territory. Thermostat failure occurs when a customer changes a setting that disconnects their thermostat from the internet. This could be caused by a change in the internet router, a new password, a new internet service provider or any other simple disconnection where the customer fails to reconnect their device.

Beginning in PY2020, site attrition and thermostat disconnections were disaggregated. In part, this helped distinguish between de-enrollments, presumably largely due to move-outs, and device disconnections which may possibly be remedied through participant outreach. This was important for modeling enrollment going forward since historically customers moving into an enrolled site were automatically enrolled in the program, but in practice the device was no longer connected or receiving dispatch signals. Functionally, this artificially lowered the observed thermostat survival rate because it was conflated with site move-outs. Just prior to the PY 2022 event season program management began periodic bulk unenrollment of devices that had been inactive for more than 365 days.

Table 4-2 and Figure 4-2 show the failure rates and survival trends based on years since enrollment and years since installation, respectively. Note that thermostat survival only includes thermostats for enrolled sites. Essentially, the site survival trend reflects the rate at which sites remain enrolled over time while the thermostat survival trend shows the rate over time at which thermostats at enrolled sites remain connected. Note that site attrition, which is a function of site move ins and move outs as well as intentional unenrollment varies more than thermostat disconnection rates which are a function of technology.

Table 4-2: Failure Rates by Cause

Program	Site Attrition			Tstat Disconnection		
	Expected	Lower bound	Upper bound	Expected	Lower bound	Upper bound
CPPTD	5.6%	4.4%	7.2%	5.8%	4.8%	7.0%
ACSDA	10.8%	9.7%	11.9%	6.6%	6.1%	7.2%

Figure 4-2: Survival Rates Over Time

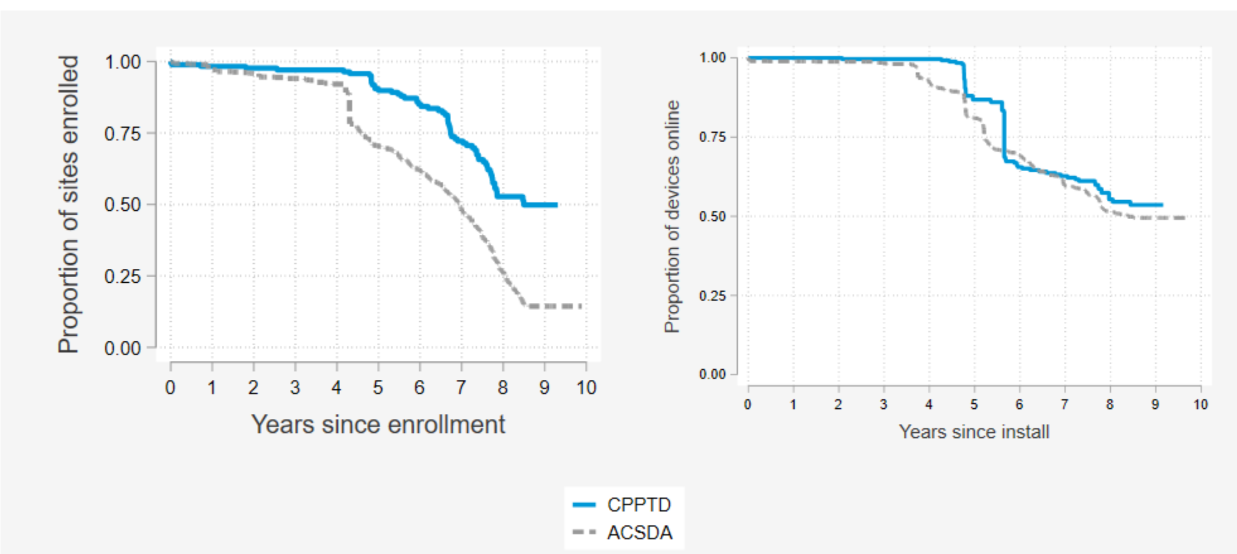


Table 4-3 shows program counts for enrolled sites, installed thermostats, and connected thermostats during the average PY 2023 weekday event. Commercial thermostat event impacts were assessed by site (premise and service point combination). After initial analysis confirmed that no perceptible, meaningful, or significant impacts were observed for sites with zero connected thermostats in 2020, the analysis was narrowed to focus on sites with at least one thermostat connected at any time during the event season. In PY 2020 SDG&E discontinued the practice of auto-enrollment and in PY 2022 SDG&E began periodic unenrollment of sites inactive for more than 365 days. Some sites with no registered thermostat are still enrolled but cannot receive dispatch signals. These sites were excluded from the ex ante enrollment forecast because they would be removed from the enrollment list before PY 2023.

Sites were grouped together into segments to assess potential differences in impacts for various groups. The segmentation, summarized in Table 4-3, was developed based on rate size and on rate characteristics which may influence impacts. The analysis was performed at the segment level so these granular impacts could therefore be summed, yielding aggregate impacts in addition to the segment specific impacts.

The segmentation criteria were defined as follows:

- **Rate:** was the site on a rate with a CPP component during the study period?
- **Rate size**: what size (demand level for rate[12]) was the site classified as throughout the study period?
- **Climate zone:** in which SDG&E climate zone was the site located?

[12] Medium sites were distinguished from Large sites by applying a maximum demand cutoff of 200 kW.

Table 4-3: Commercial Thermostat Programs and Populations

Program Rate	Size	Climate zone	Total sites	Total Connected sites	Total enrolled devices	Total connected devices
CPPTD (PSW)	Small	Coastal	53	53	66	65
		Inland	42	42	78	76
CPPTD (CPP-D)	Medium	Coastal	21	7	11	11
		Inland	30	13	29	26
ACSDA (non-res)	Large	Coastal	22	5	36	36
		Inland	17	3	20	20
	Medium	Coastal	120	37	178	176
		Inland	125	32	137	128
	Small	Coastal	226	129	268	260
		Inland	209	141	225	213
ACSDA (quasi-res)	Quasi-res	Coastal	6	4	9	9
		Inland	10	6	10	7
TOTAL			**881**	**472**	**1,067**	**1,027**

Table 4-3 also summarizes the total number of sites in each segment and the final number of sites used for the ex post event analysis once data cleaning was completed[13]. As one might expect, smaller sites are more numerous but larger sites have more devices per site. Connectivity of sites is high relative to previous program years.

Table 4-4 shows the single PY 2023 CPPTD event day, including the maximum daily temperature weighted by participating commercial thermostat sites. The SDG&E system peak occurred on August 28th, 2023 and did not coincide with a CPPTD event, though the singular event happened the following day which did coincide with the second highest load day of the year.

Table 4-4: Commercial Thermostat CPPTD Events in 2023

Event day	Day of week	Event start	Event end	Max daily temp (F)	SDG&E system load (MW)
8/29/2023	Tuesday	4:00 PM	9:00 PM	93.7	4,375

[13] The cleaning algorithm ensured that complete data was available for the study period. Loads and impacts were scaled to address the five sites not in the analysis.

4.2 DATA SOURCES AND ANALYSIS METHOD

Table 4-5 summarizes the five data sources used to conduct the commercial thermostat event impact analysis. The analysis was done by site on hourly load data. Various data sources were used to classify sites into the study segments. While different segments were developed for the various analyses in this report (rate versus technology based, event and non-event), the characteristic definitions used to build segments were consistent across analyses.

Table 4-5: Commercial Thermostat Event Impact Evaluation Data Sources

Source	Comments
Hourly interval data	▪ Summer 2023 ▪ All analysis done by site (premise id-service point id pair)
Outage information	▪ PSPS and SDG&E emergency outage data details which customers and what timeframes were impacted by outages ▪ Outage days which affected participants or control sites were excluded from the analysis
Customer characteristics	▪ Treatment: All non-residential (Commercial and Agricultural) commercial thermostat participants, including quasi-residential sites ▪ Control: All non-residential sites not on CPP or other DR programs ▪ Size category, NEM status, climate zones used in matching model selection
Thermostat installation data	▪ Installation and last connected dates
SDG&E hourly system loads	▪ Summer 2023 ▪ Used to identify non-event high system load days
Ex post weather data by weather station	▪ Used to derive cooling degree hours for impact evaluation modeling

The primary analysis method was difference-in-differences with matched controls. The distance matching approach used selected one matched control site for each of the non-residential CPPTD sites among a matched control candidate pool of roughly 10,000 commercial sites. These customers were not enrolled in CPP or other DR programs which might influence energy use. The difference-in-differences model was then used to assess impacts and standard errors for each event and each study segment.

4.3 EX POST LOAD IMPACTS

4.3.1 PEAK SHIFT AT WORK: SMALL NON-RESIDENTIAL CPP WITH TECHNOLOGY

Load reductions are a function of the reference load. When there is lower load, specifically lower cooling load, demand response programs have less opportunity for reduction. PY 2023 was a more moderate weather year compared to the extreme heat of PY 2022, thus reduction potential was lower.

Table 4-6 summarizes the load reductions for all PSW sites for the single event and 4 pm to 9 pm reductions for the average weekday event (these show the same values because there was only one event). In aggregate, the weekday events delivered 0.04 MW of load reduction across all 144 enrolled sites and the average weekday reduction per site was 0.47 kW. Though 144 devices were enrolled and 141 devices on average were connected during the PY 2023 event season. Because only connected devices can be dispatched, all reductions are delivered by these connected devices. The average reduction per connected device was 0.30 kW. Reductions were statistically significant on average. In the tables, the orange bars show a visual comparison of the reductions that are numerically labeled on the left of the bars.

Table 4-6: PSW on TD Program Event Reductions

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Enrolled Devices	Connect-ed Devices	Reduction			t-stat	Significant (90% CI)
						Aggregate (MW)	Average Site (kw)	Average Connected Tstat (kw)		
8/29/2023	4 to 9 pm	79.4	93	144	141	0.04	0.47	0.30	3.00	Yes
Avg Weekday	**4 to 9 pm**	**79.4**	**93**	**144**	**141**	**0.04**	**0.47**	**0.30**	**3.00**	**Yes**

Reductions were also analyzed within climate zone segment. Table 4-7 details the reference loads and load reductions overall and by segment for the average 4 pm to 9 pm event window. In addition to aggregate reductions, average reductions per connected thermostat are also shown. Note that the reference load for aggregate impacts includes the whole building load across all enrolled sites as recorded at the meter; the reference load for the average connected thermostat is the cooling load per connected thermostat, estimated by isolating the weather sensitive portion of whole building load. In aggregate, 11% of whole building was curtailed during the event, while 24% of cooling load was curtailed per connected device.

In aggregate, about 46% of connected devices were in the Coastal zone and these devices delivered about 70% of the 0.04 MW of reductions for the PSW program. Devices in the Coastal zone delivered more per connected device and have more AC load available for curtailment, meaning more runtime and load can be avoided by raising the set point. Though AC units must often run more often to maintain a comfortable set point in hotter environments, the PSW population is small enough this logical trend is likely obscured by noise.

Table 4-7: PSW on TD Program Average Event Reductions by Segment

Size	Climate zone	Event Window	Avg Event Temp (F)	Sites Enrolled	Enrolled Devices	Connect-ed Devices	Aggregate (MW)			Average connected tstat (kW)			t-stat
							Ref load (whole bldg)	Reduc-tion	% Reduc-tion	Ref load (cooling)	Reduc-tion	% Reduc-tion	
Small	Coastal	4 to 9 pm	77.2	49	66	65	0.20	0.03	14.5%	1.27	0.45	35%	2.99
Small	Inland	4 to 9 pm	82.6	40	78	76	0.16	0.02	10.9%	1.06	0.22	21%	1.57
All	**All**	**4 to 9 pm**	**79.4**	**93**	**144**	**141**	**0.37**	**0.04**	**11%**	**1.26**	**0.30**	**24%**	**3.00**

The average event day load shape is summarized in greater detail in Figure 4-3. Note that the figure, extracted from the Ex Post Load Impact Table, is for the CPPTD (PSW) participant population. The left panel shows the aggregate hourly MW loads (actual and counterfactual) for these sites. The right panel shows kW impacts per connected thermostat as a function of cooling load. The tables accompanying each figure show impacts for the 4 pm to 9 pm event window. Load impacts were evident for the average event window with a 11.4% aggregate reduction and a 23.7% cooling load reduction per connected thermostat.

Figure 4-3: PSW on TD: Summary for Average Weekday Event

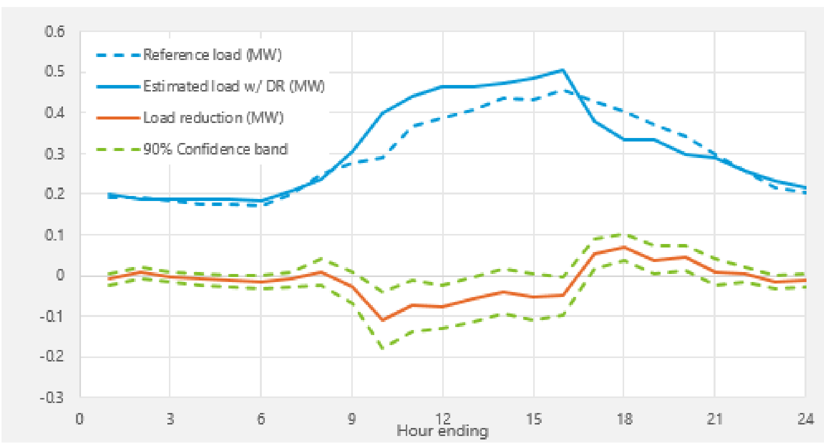
Aggregate (MW)

Table 1: Menu options

Program	CPPTD (PSW)
Type of result	Aggregate
Type of site	All
Category	All
Subcategory	All study segments
Event date	08/29/2023

Table 2: Event day information

Event start	4:00 PM
Event end	9:00 PM
Total enrolled sites	93
Total enrolled thermostats	150
Total connected thermostats	141
Percent of thermostats connected	94%
Avg load reduction 4PM-9PM	0.04
% Load reduction 4PM-9PM	11.4%



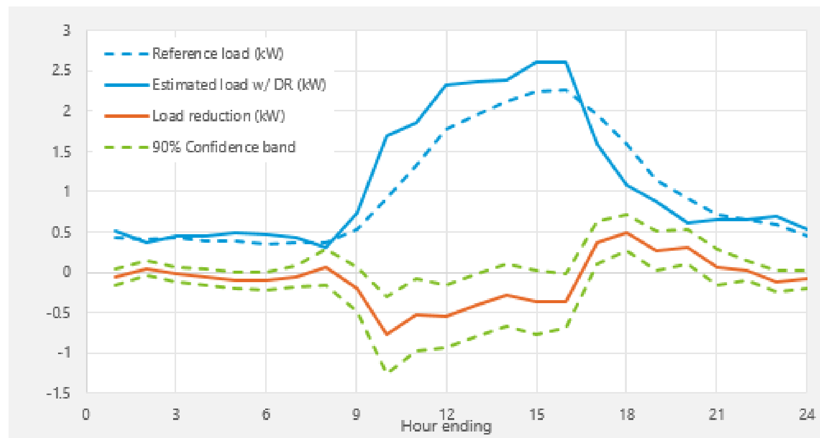
Average per Connected Thermostat – Cooling Load (kW)

Table 1: Menu options

Program	CPPTD (PSW)
Type of result	Average Connected Thermostat (Cooling load)
Type of site	All
Category	All
Subcategory	All study segments
Event date	08/29/2023

Table 2: Event day information

Event start	4:00 PM
Event end	9:00 PM
Total enrolled sites	93
Total enrolled thermostats	150
Total connected thermostats	141
Percent of thermostats connected	94%
Avg load reduction 4PM-9PM	0.30
% Load reduction 4PM-9PM	23.7%



4.3.2 CPP-D: Medium & Large Non-Residential CPP with Technology

Load reductions are a function of the reference load. When there is lower load, specifically lower cooling load, demand response programs have less opportunity for reduction. PY 2023 was a more moderate weather year compared to the extreme heat of PY 2022, thus reduction potential was lower.

Table 4-6 summarizes the load reductions for all CPP-D sites for the single event and 4 pm to 9 pm reductions for the average weekday event (these show the same values because there was only one event). In aggregate, the weekday events delivered 0.05 MW of load reduction across all 20 enrolled sites and the average weekday reduction per site was 2.73 kW. Though 40 devices were enrolled, 37 devices on average were connected during the PY 2023 event season. Because only connected devices can be dispatched, all reductions are delivered by these connected devices. The average reduction per connected device was 1.47 kW. Reductions were statistically significant on average. In the tables, the orange bars show a visual comparison of the reductions that are numerically labeled on the left of the bars.

Table 4-8: CPP-D on TD Program Event Reductions

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Enrolled Devices	Connect-ed Devices	Reduction			t-stat	Significant (90% CI)
						Aggregate (MW)	Average Site (kw)	Average Connected Tstat (kw)		
8/29/2023	4 to 9 pm	79.0	20	40	37	0.05	2.73	1.47	2.52	Yes
Avg Weekday	**4 to 9 pm**	**79.0**	**20**	**40**	**37**	**0.05**	**2.73**	**1.47**	**2.52**	**Yes**

Reductions were also analyzed within climate zone segment. Table 4-7 details the reference loads and load reductions overall and by segment for the average 4 pm to 9 pm event window. In addition to aggregate reductions, average reductions per connected thermostat are also shown. Note that the reference load for aggregate impacts includes the whole building load across all enrolled sites as recorded at the meter; the reference load for the average connected thermostat is the cooling load per connected thermostat, estimated by isolating the weather sensitive portion of whole building load. In aggregate, 13.7% of whole building load was curtailed during the event, while 38% of cooling load was curtailed per connected device.

In aggregate, about [redacted] of connected devices were in the Coastal zone and these devices delivered about [redacted] of the 0.05 MW of reductions for the CPP-D program. Devices in the Coastal zone delivered [redacted]

Table 4-9: CPP-D on TD Program Average Event Reductions by Segment

Size	Climate zone	Event Window	Avg Event Temp (F)	Sites Enrolled	Enrolled Devices	Connect-ed Devices	Aggregate (MW)			Average connected tstat (kW)			t-stat
							Ref load (whole bldg)	Reduc-tion	% Reduc-tion	Ref load (cooling)	Reduc-tion	% Reduc-tion	
Medium	Coastal	4 to 9 pm	[redacted]										
	Inland	4 to 9 pm											
All	All	4 to 9 pm	79.0	20	40	37	0.40	0.05	13.7%	3.85	1.47	38%	2.52

The average event day load shape is summarized in greater detail in Figure 4-3. Note that the figure, extracted from the Ex Post Load Impact Table, is for the CPPTD (CPP-D) participant population. The left panel shows the aggregate hourly MW loads (actual and counterfactual) for these sites. The right panel shows kW impacts per connected thermostat as a function of cooling load. The tables accompanying each figure show impacts for the 4 pm to 9 pm event window. Load impacts were evident for the average event window with a 13.7% aggregate reduction and a 38.3% cooling load reduction per connected thermostat.

Figure 4-4: CPP-D on TD: Summary for Average Weekday Event

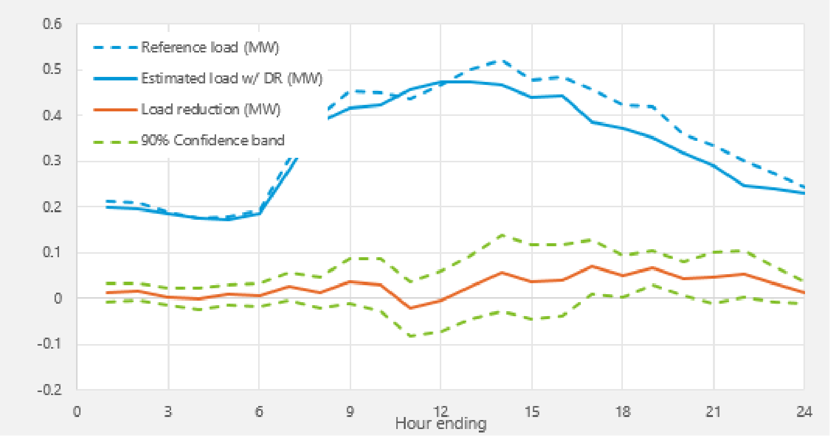
Aggregate (MW)

Table 1: Menu options

Program	CPPTD (CPP-D)
Type of result	Aggregate
Type of site	All
Category	All
Subcategory	All study segments
Event date	Avg Weekday 4-9pm

Table 2: Event day information

Event start	4:00 PM
Event end	9:00 PM
Total enrolled sites	20
Total enrolled thermostats	40
Total connected thermostats	37
Percent of thermostats connected	93%
Avg load reduction 4PM-9PM	0.05
% Load reduction 4PM-9PM	13.7%



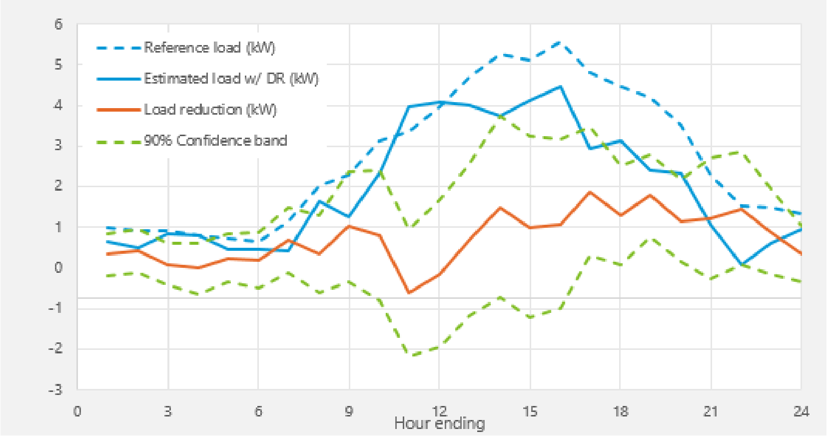
Average per Connected Thermostat – Cooling Load (kW)

Table 1: Menu options

Program	CPPTD (CPP-D)
Type of result	Average Connected Thermostat (Cooling load)
Type of site	All
Category	All
Subcategory	All study segments
Event date	Avg Weekday 4-9pm

Table 2: Event day information

Event start	4:00 PM
Event end	9:00 PM
Total enrolled sites	20
Total enrolled thermostats	40
Total connected thermostats	37
Percent of thermostats connected	93%
Avg load reduction 4PM-9PM	1.47
% Load reduction 4PM-9PM	38.3%



4.3.3 AC Saver Day Ahead: Non-Residential with Technology

There were no AC Saver Day Ahead events called for the PY 2023 event season so ex post impacts cannot be assessed. Ex ante load impacts were estimated using PY 2020 event impacts.

4.3.4 AC Saver Day Ahead: Quasi-Residential with Technology

There were no AC Saver Day Ahead events called for the PY 2023 event season so ex post impacts cannot be assessed. Ex ante load impacts were estimated using PY 2020 event impacts.

4.4 EX ANTE LOAD IMPACTS

On December 14, 2023, Decision (D.) 23-12-005 OP28 ordered SDG&E to terminate the AC Saver program at the end of 2023. Therefore, the AC Saver Day Ahead Commercial ex-ante load impact section is not included in the report but the thermostats in rates (CPP in TD and PSW in TD) are included in the report.

A key objective of the 2023 evaluation is to quantify the relationship between demand reductions, temperature, and hour of day. Ex ante impacts are estimated load reductions as a function of weather conditions, time of day, and forecasted changes in enrollment. By design, they reflect planning conditions defined by normal (1-in-2) and extreme (1-in-10) peak demand weather conditions. The historical load patterns and performance during actual events are used the reductions for a standardized set of weather conditions.

At a fundamental level, the process of estimating ex ante impacts included five main steps:

1. Estimate the relationship between cooling load per thermostat (absent DR) and weather by hour of day
2. Estimate the relationship between cooling load percent reduction, temperature, and hours into an event using historical event data
3. Predict cooling loads and percent reductions for 1-in-2 and 1-in-10 weather year conditions
4. Combine the loads and percent reductions to estimate impacts per connected thermostat
5. Incorporate the enrollment/device forecast and device connectivity forecast

4.4.1 RELATIONSHIP OF CUSTOMER LOADS AND PERCENT REDUCTIONS TO WEATHER

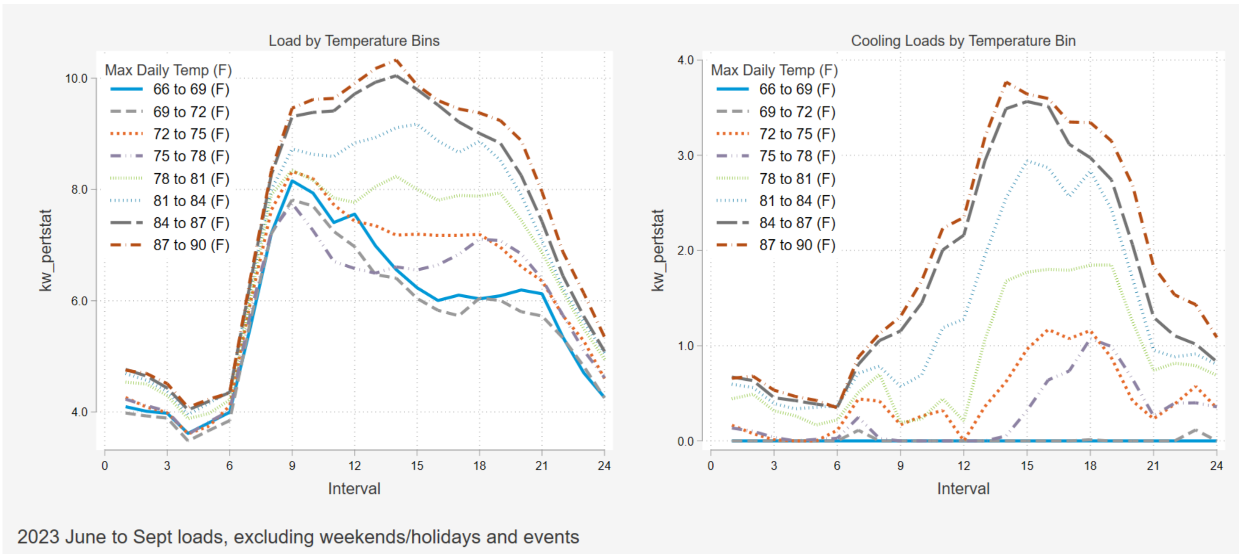
Figure 4-5 summarizes the relationship between weather for commercial customers with commercial thermostats on CPP rates. Only days when the smart thermostat resources were not dispatched are included. Overall, energy demand and discretionary load increases with hotter weather.

These figures also provide an estimate for typical cooling loads for commercial thermostat sites by assessing how whole building loads per thermostat vary with temperature (left panel). The baseload is estimated by the load on cooling neutral days (max daily temperatures around 70 degrees, e.g. blue line in left panel). Net cooling loads (right panel) are total loads for each weather bin minus the baseload. Note that hotter temperature bands were available for plotting for CPPTD devices which skew more heavily toward the Inland zone.

On days with the highest usage (the 87-90 max daily temperature band) average whole building load per thermostat for CPPTD devices is about 10 kW during the typical 4-9 pm CPP event window, but cooling loads are less than half of this, or about 3.75 kW per thermostat.

Because impacts are directly driven by connected thermostats controlling cooling loads, ex ante impacts were estimated as a function of cooling loads on a per thermostat basis. Figure 4-5 shows participant loads for the PSW on TD and CPP-D on TD program combined.

Figure 4-5: Weather Sensitivity of CPPTD Program Participant Loads



Because the commercial thermostats are dispatched automatically for events, the main driver of differences in ex ante impacts are differences in loads. The percent change in energy use was estimated for each of the ex post segments defined in Table 4-3 and applied to 1-in-2 and 1-in-10 weather year customer loads.

Figure 4-6 shows hourly event percent reductions for historical weekday events as a function of hourly temperatures for sites on each CPP-TD program. Reductions are largely positive and statistically significant in magnitude, a handful are near zero (and not statistically significant) and few are negative, indicating an increase in load, but mostly insignificant. Impacts which were not statistically significant were assumed to be zero for ex ante impact modeling purposes.

The PY 2022 and 2023 impacts for the CPPTD (customers under CPP on TD and customers under PSW on TD) programs are shown in Figure 4-6. The two program years were combined for PSW and CPP-D, and both exhibit a relatively flat relationship between impacts and temperature. However, an additional challenge for PSW was that the population changed substantially between PY 2022 and PY 2023. Specifically, the population dropped from 172 sites (and 288 connected devices) to 93 sites (and 141 connected devices). Further the cooling load per connected device in PY 2022 was 2.7 kW in PY 2022 compared to 1.3 kW in PY 2023. Essentially, the population and load per device were each reduced by roughly 50%. Despite this, the aggregate load reductions in each program year remained at about 0.04 MW. Essentially, half of the thermostats, each controlling half the cooling load of thermostats in PY 2022 delivered the same reduction, so the cooling load reductions per connected device increased by fourfold in PY 2023 (from about 6% to about 24%). In practice, this increase likely reflects fundamental differences between the average participant across the two program years. To address this, PY 2022 were adjusted upward by the same fourfold factor before incorporating into the ex ante modeling along with the PY 2023 ex post impacts.

Figure 4-7 shows the original impacts (which match the left panel of Figure 4-6) and resulting impacts after the scaling factor was applied to the PY 2022 impacts. Impacts which were not statistically significant were assumed to be zero for ex ante impact modeling purposes.

Figure 4-6: 2023 and 2022 CPPTD Hourly Reductions and Temperatures

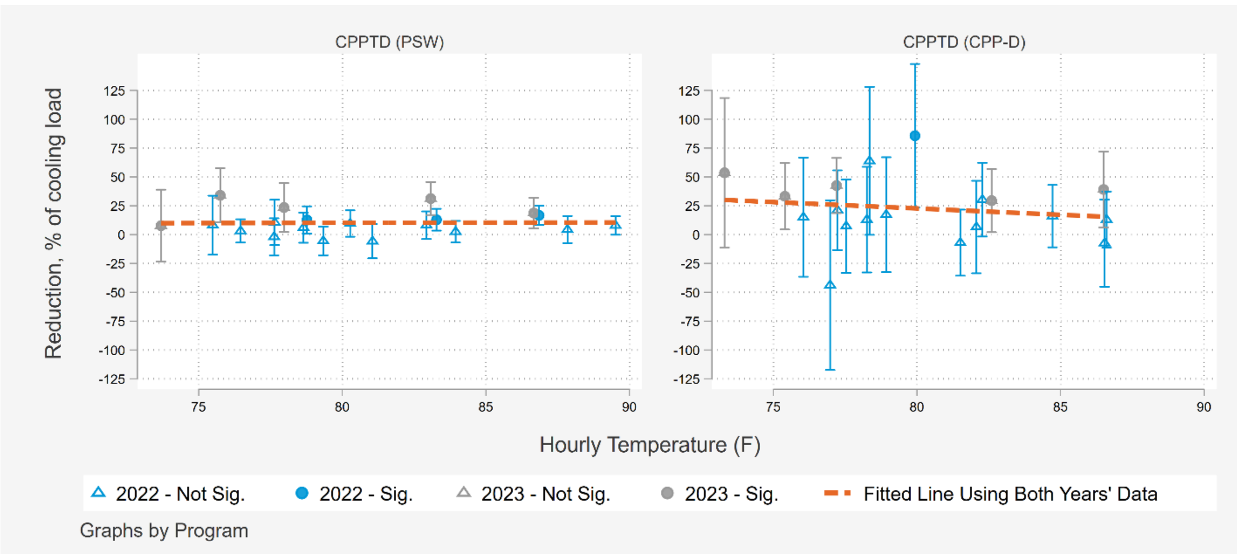
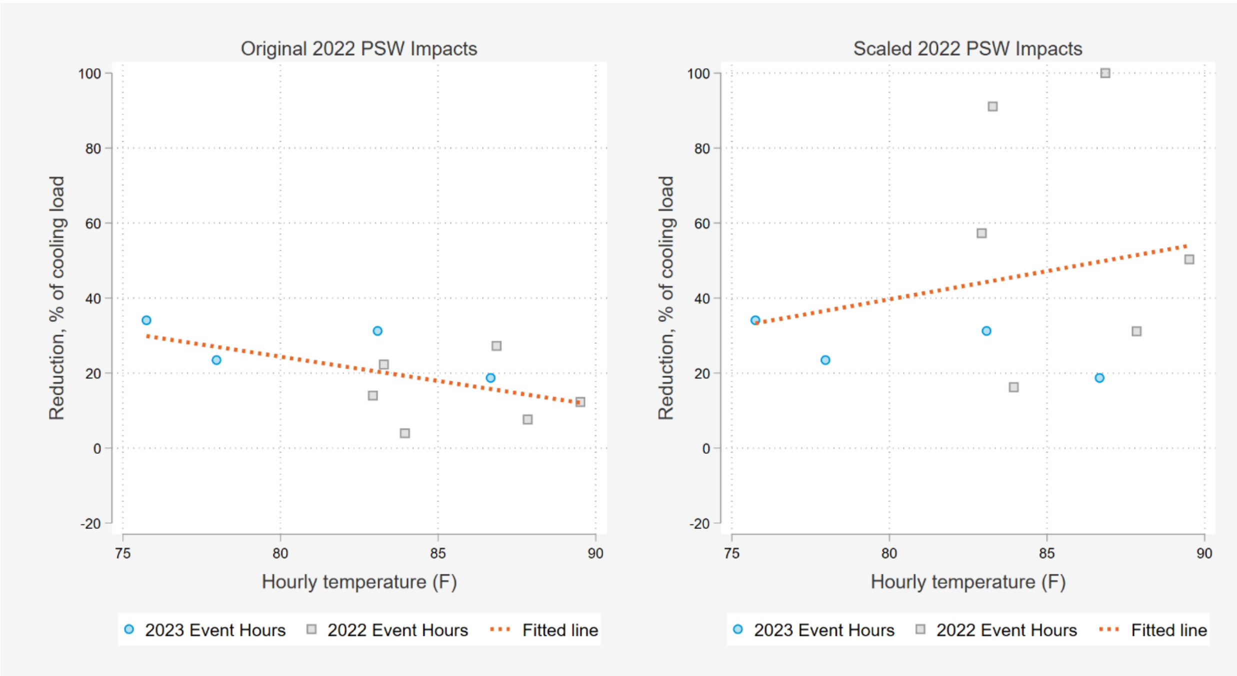


Figure 4-7: 2023 and 2022 CPPTD – PSW on TD Hourly Reductions and Temperatures with Scaling



4.4.2 Ex Ante Load Impacts

Table 4-10 summarizes the ex ante demand reduction capability by forecast year for 1-in-2 SDG&E weather planning conditions across both CPP-TD programs. The tables reflect dispatchable demand reductions available from 4 pm to 9 pm under August 1-in-2 peaking conditions in alignment with the planning conditions used for resource adequacy attribution. They incorporate an enrollment forecast for sites and devices developed using the following inputs and assumptions:

- Site attrition and device connectivity rates described in section 4.1. These are used to produce forecast for enrolled sites, total thermostats, and connected thermostats over time.
- Modest new enrollments for CPP-TD programs until 2025. Site counts are held constant after 2029. This aligns with CPPTD expectations of the continuing CCA transition.

Table 4-10 summarizes expected August peak day 1-in-2 reductions for the two CPP-TD programs. Ultimately, forecasted ex ante load reductions reflect load reductions are delivered by connected devices among enrolled sites. Reductions are a function of the number of enrolled sites (which decrease over time), the connectivity rate over time for installed devices (which decreases over time), and the estimated load reduction per connected device (which stays constant over time on a percentage basis). The estimated load reductions are also influenced by reference loads. Load impacts are assumed to slowly decrease over time as participants un-enroll (or move out) and thermostats become disconnected.

Table 4-10: Non-residential Smart Thermostat Portfolio Impacts for 1-in-2 SDG&E Weather Conditions, August Monthly Peak Day

Year	CPP-TD (MW)		Total (MW)	Sites
	PSW	CPP-D		
2023	0.05	0.02	0.06	116
2024	0.04	0.02	0.06	112
2025	0.04	0.02	0.05	105
2026	0.03	0.01	0.05	99
2027	0.03	0.01	0.04	94
2028	0.03	0.01	0.04	89
2029	0.02	0.01	0.03	84
2030	0.02	0.01	0.03	82
2031	0.02	0.01	0.03	82
2032	0.02	0.01	0.03	82
2033	0.02	0.01	0.03	82
2034	0.02	0.01	0.02	82

Table 4-11 summarizes the ex ante demand reduction capability by forecast year for different planning conditions, respectively, for sites on dispatchable rates (CPP-TD). The tables reflect dispatchable demand reductions available from 4 pm to 9 pm on August monthly peaking conditions for 1-in-2 and 1-in-10 weather conditions. They align with the planning conditions used for resource adequacy attribution. The enrollment forecast for the number of enrolled sites was developed by SDG&E and was also applied to the counts of installed thermostats and shows an initial increase followed by a decrease in sites, installed devices, and connected devices over time for the CPPTD programs.

Table 4-11: CPP-TD Portfolio Ex Ante Impacts for August Monthly Peak Day

Year	Sites	Tstats enrolled	Tstats connected	Average Reference Load (kW/site)	CAISO (MW)		SDG&E (MW)	
					1-in-2	1-in-10	1-in-2	1-in-10
2023	116	195	183	12	0.08	0.07	0.06	0.06
2024	112	188	170	12	0.07	0.06	0.06	0.06
2025	105	177	151	12	0.06	0.05	0.05	0.05
2026	99	167	134	12	0.06	0.05	0.05	0.05
2027	94	158	119	12	0.05	0.04	0.04	0.04

Year	Sites	Tstats enrolled	Tstats connected	Average Reference Load (kW/site)	CAISO (MW)		SDG&E (MW)	
					1-in-2	1-in-10	1-in-2	1-in-10
2028	89	149	106	12	0.04	0.04	0.04	0.04
2029	84	140	94	12	0.04	0.03	0.03	0.03
2030	82	138	87	12	0.04	0.03	0.03	0.03
2031	82	138	82	12	0.03	0.03	0.03	0.03
2032	82	138	77	12	0.03	0.03	0.03	0.03
2033	82	138	73	12	0.03	0.03	0.03	0.03
2034	82	138	69	12	0.03	0.02	0.02	0.02

4.4.3 Comparison of Ex Post And Ex Ante Load Impacts

Table 4-12 compares the CPPTD observed demand reductions from PY 2023 events to the PY 2023 reductions expected for the 1-in-2 weather conditions used for planning. Results are shown for the 4 to 9 pm resource adequacy window. In 2023, CPPTD customers delivered 0.09 MW during the dispatch period of 4 to 9 pm. Ex post RA period reductions align with actual event hours since the shift of the event window changed in PY 2022. Ex ante percentage impacts for the resource adequacy window are lower than the corresponding ex post impacts. This is in part because daily max ex ante temperatures for 1-in-2 weather conditions shown here are several degrees lower than for the events called in 2022 (ex post). Ex post results also reflect a changing mix of connected devices over the course of the summer and the unique hourly temperature profiles of each event, whereas ex ante impacts assume a fixed number of connected devices and weather for a single peak day.

Table 4-12: CPPTD Comparison of Ex Post and Ex Ante Load Impacts for 2023

Result Type	Day Type and Period	Sites	Tstats connected	Load without DR (MW)	Load Reduction (MW)	% Reduction	Daily Max Temp (F)
Ex Post Avg. Weekday (PY2023 Results)	Resource Adequacy Period (4 to 9pm)	113	178	0.74	0.09	12.6%	93.6
Ex ante SDG&E	1-in-2 Weather August Peak (4 to 9pm)	116	183	0.77	0.06	8.4%	93.5

Result Type	Day Type and Period	Sites	Tstats connected	Load without DR (MW)	Load Reduction (MW)	% Reduction	Daily Max Temp (F)
Ex ante CAISO	1-in-2 Weather August Peak (4 to 9pm)	116	183	0.74	0.08	10.3%	89.9

*Table shows portfolio impacts. To avoid double counting, it excluded commercial thermostats and customers dually enrolled in other DR programs.

4.4.4 Ex Ante Load Impact Slice-of-Day Tables

Table 4-13 and Table 4-14 show the CPP-TD 2023 ex ante aggregate hourly impacts for each month under CAISO and SDG&E monthly peaking conditions, respectively. The tables are designed to enable the CPUC's Slice-of-Day Resource Adequacy requirements. The estimated reductions are greatest in August and September as there is the most amount of cooling load available to be curtailed. Reductions are zero or negligible in December through March when there is no cooling load to be curtailed.

Table 4-13: Slice of Day Table for CPP-TD, CAISO 1-in-2 Weather Year Monthly Peak Day (Aggregate Impacts (MW))

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.00	0.00	0.00	0.03	0.04	0.05	0.08	0.07	0.06	0.04	0.05	0.00
18	0.00	0.00	0.00	0.04	0.04	0.06	0.09	0.08	0.08	0.05	0.05	0.00
19	0.00	0.00	0.00	0.04	0.04	0.06	0.10	0.10	0.09	0.07	0.06	0.00
20	0.00	0.00	0.00	0.04	0.03	0.06	0.09	0.10	0.10	0.08	0.05	0.00
21	0.00	0.00	0.00	0.01	0.01	0.02	0.03	0.04	0.04	0.03	0.02	0.00
22	0.00	0.00	0.00	0.01	0.01	0.02	0.03	0.03	0.03	0.03	0.02	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Demand reductions are positive (Blue)
Load increases are negative (Orange)

Table 4-14: Slice of Day Table for CPP-TD, SDG&E 1-in-2 Weather Year Monthly Peak Day (Aggregate Impacts (MW))

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.00	0.00	0.00	0.04	0.03	0.04	0.10	0.05	0.01	0.03	0.06	0.00
18	0.00	0.00	0.00	0.04	0.04	0.05	0.11	0.06	0.03	0.04	0.06	0.00
19	0.00	0.00	0.00	0.04	0.04	0.05	0.10	0.08	0.07	0.06	0.06	0.00
20	0.00	0.00	0.00	0.05	0.04	0.05	0.10	0.10	0.10	0.07	0.05	0.00
21	0.00	0.00	0.00	0.02	0.01	0.02	0.03	0.04	0.05	0.03	0.02	0.00
22	0.00	0.00	0.00	0.02	0.01	0.02	0.03	0.04	0.04	0.03	0.02	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Demand reductions are positive (Blue)

Load increases are negative (Orange)

5 CONCLUSIONS AND RECOMMENDATIONS

The two different interventions – CPP-TOU and commercial thermostats – have been delivering fewer demand reductions as the enrolled populations decline. Most commercial thermostat program participants enrolled several years ago in conjunction with the rollout of default time varying rates, and smart thermostats have not been meaningfully marketed to commercial customers in recent years. The population has declined as inactive participants have been periodically removed to manage program cost-effectiveness. Most commercial thermostat programs were not dispatched in PY 2023 but the one commercial thermostat program that was dispatched (Peak Shift at Work for small commercial sites) delivered statistically significant demand reductions and substantially higher percentage reductions that in prior years. This indicates that there may be potential for future reductions with targeted marketing to engaged customers. The small non-residential CPP-TOU rate participation has also substantially dwindled as customers move to other energy providers, primarily Community Choice Aggregation. The remaining population did not produce statistically significant reductions during the single event called in PY 2023. The recommendations below may not be currently funded, and costs need to be considered alongside other research and program priorities. For clarity, we present the recommendations for technology deployment programs and critical peak pricing separately.

5.1 TECHNOLOGY DEPLOYMENT RECOMMENDATIONS

- **Continue disenrolling thermostats with prolonged disconnections**: Thermostats which are not connected cannot respond to dispatch signals or produce reductions. However, they still cause the program to incur technology costs which accrue on a per enrolled device basis.

- **Target the program to engaged customers:** Despite the PSW PY 2023 population being half that of PY 2022, the same load reduction was produced, meaning that the same benefit was achieved at lower cost.

5.2 SMALL COMMERCIAL CRITICAL PEAK PRICING RECOMMENDATIONS

- **Assess if additional communications encouraging response improve reductions using randomized controlled trials.** The magnitude of demand reductions during events is small on a percentage basis, with ample room to improve reductions. Most reductions were delivered by sites receiving event notifications. Additional communications require resources and their effectiveness at improving price response is unknown. Because of the potential, however, we recommend testing the effectiveness of more education regarding event response. It is critical, however, for the test to be implemented using randomized control trials, so it is possible to assess if the communications had any impact on price response.

- **Notification rates for small CPP can be improved.** Customers elect whether to sign up for notifications and by which channels they receive notification. Because notification is closely linked to response, additional efforts to improve notification rates are recommended. Sites receiving event notifications tend to produce greater impacts so an increase in notification rates has the potential to meaningfully increase load reductions.