Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

REPORT

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2023 Load Impact Evaluation for Pacific Gas & Electric's Emergency Load Reduction Pilot

Prepared for PG&E
By Demand Side Analytics, LLC
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ABSTRACT

This study quantifies the load impacts of the Residential and Non-Residential Emergency Load Reduction Program pilot. The study focuses on two primary research questions: What were the 2023 demand reductions due to dispatch operations? What is the magnitude of future dispatchable load reduction capability for 1-in-2 and 1-in-10 weather conditions?

The pilot was rolled out in 2021 upon direction by the Commission to expand the state's portfolio of emergency reliability resources beyond those available in CAISO capacity markets and utility specific load modifying resources such as Critical Peak Pricing. Events are triggered by the CAISO in response to extreme grid stress, and event reductions are settled via a $2/kWh payment, determined using baseline settlement rules. Nine non-residential ELRP events were called in PY 2023, with different subgroups being dispatched for specific events. The average PY 2023 weekday 6pm to 9pm event did not produce meaningful load reductions when evaluated across all non-residential ELRP subgroups. Seven A.4 residential ELRP events were called in PY 2023, and the average event produced 18.1 MW of aggregate load reduction. No A.6 residential events were called.

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1 EXECUTIVE SUMMARY

The Emergency Load Reduction Program (ELRP) pilot is a demand response program with direct settlements and performance payments to participant sites designed to access additional incremental load reduction during times of high grid stress and emergencies involving inadequate market resources, with the goal of avoiding rotating outages. The pilot was rolled out in 2021 upon direction by the Commission to expand the state's portfolio of emergency reliability resources beyond those available in CAISO capacity markets and utility specific load modifying resources such as Critical Peak Pricing. Two distinct groups of customers are eligible for ELRP participation: (Group A) directly enrolled residential and non-residential customers and aggregators, and (Group B) third-party demand response providers (DRPs) with market-integrated proxy DR (PDR) resources.

Group A: Direct enrolled residential and non-residential customers and aggregators:

- A.1. Non-Residential Customers (BIP, Non-Res CPP, SCE's RTP, AP-I, SDP-C allowed).
- A.2. Non-Residential Aggregation (BIP + Non-BIP Aggregators).
- A.3. Rule 21 Exporting Distributed Energy Resources (DER).
- A.4. Virtual Power Plant (VPP) Aggregators (AC Cycling allowed when using submetering to determine ILR; includes SCE SDP and SEP, PG&E's Smart AC Switches or BYOT, and SDG&E's AC Saver).
- A.5. Vehicle-Grid-Integration (VGI) Aggregators (AC Cycling Allowed when using submetering to determine ILR; includes SCE SDP, PG&E's Smart AC Switches or BYOT, and SDG&E's AC Saver).
- A.6. Residential Customers (Res CPP allowed).

Group B: Market-integrated PDR resources:

- B.1. Third-party DR Providers.
- B.2. IOU Capacity Bidding Program (CBP) Aggregators.

ELRP A.6 was rolled out in May of 2022 upon direction by the Commission to capture additional residential emergency load reduction resources. ELRP A.6 is a behavioral demand response program with direct settlements and performance payments to participants, which is currently planned to operate through 2025. All other ELRP subgroups are expected to discontinue after 2027. All ELRP groups remunerate participant site performance via a $2/kWh payment, determined using baseline settlement rules specific to each subgroup. However, settlement payments for A.6 will decrease in 2024 and 2025 to $1/kWh. The eligibility, targeting, and rollout of each subgroup are entirely different.

This study analyzes two primary research questions:

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

Table 1-1 summarizes the estimated ex post demand reductions for the average weekday ELRP event for each subgroup in which PG&E customers are enrolled (non-residential and residential). All impacts are incremental to other DR program impacts and statistical significance is noted for each subgroup. Subgroup A.4 [redacted] produced statistically significant incremental impacts. Subgroup A.6 was not dispatched in PY 2023. There were no enrollments in groups A.3 or B.1 in PY 2023.

Table 1-1: Summary of 2023 Average Weekday Event Ex Post Demand Reductions[1]

ELRP Group	Sector(s)	Sites	Load without DR (MW)	Load reduction (MW)	% Reduction	Significant (90% CI)	Significant (95% CI)
A.1: Non-Res	Non-Residential	10,474	614.44	5.03	0.8%	No	No
A.1-BIP: Non-Res Customers	Non-Residential	13	[redacted]				
A.2-BIP: Non-Res Aggregators	Non-Residential	29					
A.4: Virtual Power Plants (VPPs)	Non-Residential & Residential	6,158	1.61	17.71	1098.6%	Yes	Yes
A.5: Vehicle-Grid-Integration (VGI) Aggregators	Non-Residential	3	[redacted]				
A.6: Residential Customers	Residential	1,802,984	N/A	N/A	N/A	N/A	N/A
B.2: IOU Capacity Bidding Programs	Non-Residential	601	71.02	-1.82	-2.6%	No	No

Table 1-2 summarizes forecasted site enrollments by subgroup, including the A.6 subgroup which is only approved through 2025. For subgroups A.1-BIP, A.2-BIP, A.5, and B.2 enrollments are expected to remain flat and end after 2027. Subgroups A.1 and A.4 are expected to grow until 2027. Subgroup A.6 enrollment is forecasted to decline until 2025 when it will be either renewed or discontinued.

[1] The average weekday event results incorporate impacts across multiple event windows (e.g. 6 pm to 9 pm and 8pm to 9 pm) as not all groups and events were dispatched for the same event windows.

Table 1-2: Summary of Ex ante Site Enrollments

Year	A.1	A.1-BIP	A.2-BIP	A.4	A.5	A.6	B.2	Total
2023	10,394	13	18	6,125	3	1,610,556	559	1,627,668
2024	11,770	13	18	6,944	3	1,493,633	700	1,513,081
2025	13,502	13	18	7,985	3	1,261,526	700	1,283,747
2026	15,035	13	18	8,681	3	0	700	24,450
2027	16,384	13	18	9,185	3	0	700	26,303

Table 1-3 summarizes portfolio adjusted ELRP dispatchable ex ante reductions under August monthly peaking conditions for a PG&E 1-in-2 weather year. Table 1-4 shows the same for program specific impacts. ELRP load reductions are assumed to be a function of curtailment of weather sensitive load on a percent basis except for exporting subgroups (A.4, A.5) for which reductions are the same for all weather specifications in PY 2023. The results in the table below reflect the reduction capability from 4pm to 9pm, which aligns with resource adequacy requirements. [redacted]

Table 1-3: Summary of Portfolio Adjusted Ex Ante Dispatchable Demand Reductions, August Monthly Peak Day, PG&E 1-in-2 Weather

Year	A.1	A.1-BIP	A.2-BIP	A.4	A.5	A.6	B.2	Total
2023	22.56	2.20	2.41	17.37	[redacted]	50.21	0.82	95.58
2024	26.26	4.88	1.74	19.14	[redacted]	60.70	1.00	113.72
2025	30.28	4.88	1.74	22.01	[redacted]	54.19	1.00	114.10
2026	33.81	4.88	1.74	23.93	[redacted]	0.00	1.00	65.35
2027	36.91	4.88	1.74	25.32	[redacted]	0.00	1.00	69.84

Table 1-4: Summary of Program Specific Ex Ante Dispatchable Demand Reductions, August Monthly Peak Day, PG&E 1-in-2 Weather

Year	A.1	A.1-BIP	A.2-BIP	A.4	A.5	A.6	B.2	Total
2023	22.63	0.00	0.00	17.37	[redacted]	53.75	1.06	94.81
2024	26.26	0.00	0.00	19.14	[redacted]	63.60	1.27	110.27
2025	30.28	0.00	0.00	22.01	[redacted]	55.89	1.27	109.45
2026	33.81	0.00	0.00	23.93	[redacted]	0.00	1.27	59.01
2027	36.91	0.00	0.00	25.32	[redacted]	0.00	1.27	63.49

2 INTRODUCTION

The Emergency Load Reduction Program (ELRP) pilot is a demand response program with direct settlements and performance payments to participant sites designed to access additional incremental load reduction during times of high grid stress and emergencies involving inadequate market resources, with the goal of avoiding rotating outages. The pilot was rolled out in 2021 upon direction by the Commission to expand the state's portfolio of emergency reliability resources beyond those available in CAISO capacity markets and utility specific load modifying resources such as Critical Peak Pricing. Two distinct groups of customers are eligible for ELRP participation: (Group A) directly enrolled residential and non-residential customers and aggregators, and (Group B) third-party demand response providers (DRPs) with market-integrated proxy DR (PDR) resources.

Group A: Direct enrolled residential and non-residential customers and aggregators:

- A.1. Non-Residential Customers (BIP, Non-Res CPP, SCE's RTP, AP-I, SDP-C allowed).
- A.2. Non-Residential Aggregation (BIP + Non-BIP Aggregators).
- A.3. Rule 21 Exporting Distributed Energy Resources (DER).
- A.4. Virtual Power Plant (VPP) Aggregators (AC Cycling allowed when using submetering to determine ILR; includes SCE SDP and SEP, PG&E's Smart AC Switches or BYOT, and SDG&E's AC Saver).
- A.5. Vehicle-Grid-Integration (VGI) Aggregators (AC Cycling Allowed when using submetering to determine ILR; includes SCE SDP and SEP, PG&E's Smart AC Switches or BYOT, and SDG&E's AC Saver).
- A.6. Residential Customers (Res CPP allowed).

Group B: Market-integrated PDR resources:

- B.1. Third-party DR Providers.
- B.2. IOU Capacity Bidding Program (CBP) Aggregators.

ELRP A.6 was rolled out in May of 2022 upon direction by the Commission to capture additional residential emergency load reduction resources. ELRP A.6 is a behavioral demand response program with direct settlements and performance payments to participants, which is currently planned to operate through 2025. All other ELRP subgroups are expected to discontinue after 2027. All ELRP groups remunerate participant site performance via a $2/kWh payment, determined using baseline settlement rules specific to each subgroup. However, settlement payments for A.6 will decrease in 2024 and 2025 to $1/kWh. The eligibility, targeting, and rollout of each subgroup are entirely different.

2.1 PROGRAM BACKGROUND

ELRP differs from market programs like Base Interruptible Load (BIP) and Capacity Bidding Program (CBP) in its eligibility, trigger, and settlement rules. Namely:

- **Deployment Triggers**: ELRP is dispatched via emergency triggers, as opposed to economic triggers.
- **Payment Rules**: ELRP has no penalties or capacity payments.
- **Baseline Settlement Rules**: ELRP utilizes top 10 of 10 or top 5 of 10 baselines with optional asymmetric adjustments and treatment of net exports (option to include for some groups, only exports considered for other groups).
- **Back Up Generation (BUG) Rules**: ELRP allows for BUG operation during events. BUG is generally ineligible for market programs.

Group A participant sites must, in general, not be enrolled in a supply-side DR program offered by an IOU, third-party DRP, or CCA. Customers or providers which are enrolled in supply-side DR programs may be eligible for enrollment in Group B. Table 2-1 summarizes the eligibility rules for each subgroup.

Table 2-1: ELRP Group Eligibility Requirements[2]

	Eligibility Requirements
A.1	Bundled and unbundled non-residential customers that meet all of the following criteria may directly participate in ELRP: ▪ Customer's service account is classified as non-residential; and ▪ Customer's service account must be able to reduce load by a minimum of one kilowatt during an ELRP event; and ▪ Customer's service account is not simultaneously enrolled in another DR program offered by an IOU, demand response provider (DRP), or Community Choice Aggregator (CCA), with the exception that dual enrollment is allowed in PG&E's Base Interruptible Program (BIP) subject to compliance with the BIP tariff.
A.2	Third-party, non-residential aggregators—including those participating in PG&E's Base Interruptible Program (BIP)—are eligible to participate in ELRP. Aggregators can only add bundled and unbundled non-residential service accounts for ELRP that meet the following criteria:

[2] https://elrp.olivineinc.com/_files/pge/elrp/PGE-ELRP-Group-A-Terms-and-Conditions.pdf
https://elrp.olivineinc.com/_files/pge/elrp/PGE-ELRP-Group-B-Terms-and-Conditions.pdf
https://powersaver.pge.com/terms-and-conditions/

<table>
<tr><th colspan="2">Eligibility Requirements</th></tr>
<tr><td></td><td>Customer’s service account is classified as non-residential; and
Customer’s service account is not simultaneously enrolled in another DR program offered by an IOU (with the exception of BIP), demand response provider (DRP), or Community Choice Aggregator (CCA).
BIP aggregators must enroll their entire BIP portfolio. If a BIP Aggregator chooses not to participate, its non-residential customers cannot independently participate in ELRP under Sub-Group A.1., unless their service account specific BIP firm service level can be determined. For non-BIP aggregators, the aggregated resource capacity meets or exceeds 500 kW.</td></tr>
<tr><td>A.3</td><td>Bundled and unbundled non-residential customers that meet all of the following criteria may directly participate in ELRP:
Customer’s service account is not simultaneously enrolled in any market integrated DR program offered by PG&E, a third-party DRP, or CCA; and
Customer’s service account possesses a behind-the-meter (BTM) Rule 21- interconnected device (including Prohibited Resources/BUG) with an existing Rule 21 export permit; and
Customer’s BTM Rule 21 physical interconnected device has a minimum capacity of 25 kW and is able to export a minimum of 25 kW for at least one hour in compliance with Rule 21 and other applicable regulations and permits during an ELRP event</td></tr>
<tr><td>A.4</td><td>A third-party aggregator managing a BTM hybrid Virtual Power Plant (VPP) consisting of storage paired with net energy metering (NEM) solar and/or stand-alone storage deployed with residential (bundled or unbundled) and/or non-residential (bundled or unbundled) customers, whose VPP meet all of the following criteria, is eligible participate in ELRP:
The VPP or any customer site within the aggregation is not simultaneously enrolled in a market-integrated DR program offered by PG&E, a third-party DRP, or CCA; and
All sites within the VPP aggregation are located within PG&E’s service territory; and
The aggregated BTM storage capacity of the VPP is a minimum of 500 kW, where the VPP size is determined by summing the Rule 21 interconnected capacity of the individual storage devices comprising the aggregation, and
Each site within the VPP aggregation has a Rule 21 permit and operates in a manner compliant with existing rules and tariffs applicable to the site.</td></tr>
<tr><td>A.5</td><td>A third-party aggregator managing a Vehicle-Grid-Integration (VGI) aggregation consisting of any combination of electric vehicles and charging stations – including those that are capable of managed one-way charging (V1G) and bi-directional charging and discharging (V2G) deployed with residential (bundled or unbundled) or non-residential (bundled or unbundled) customers that meets the following criteria, is eligible to participate in ELRP:
The VGI aggregation or any customer site within the aggregation is not simultaneously enrolled in a market-integrated, supply-side DR program offered by PG&E, third-party DRP, or CCA, and
All sites within the VGI aggregation are located within PG&E’s service territory, and</td></tr>
</table>

	Eligibility Requirements
	▪ All sites within the VGI aggregation have operational electric vehicle supply equipment (EVSE), and ▪ Sites within the VGI aggregation that intend to implement V2G must have UL 1741 SA certification, any subsequent UL 1741 supplement certification as required in Rule 21 or Smart Inverter Working-Group recommended smart inverter functions and satisfies all other Rule 21 interconnection requirements, and ▪ The VGI aggregation can contribute Incremental Load Reduction (ILR) equal to or greater than 25 kW for a minimum of one hour during an ELRP event.
A.6	PG&E shall determine at its sole discretion Participant's eligibility which must include: ▪ Participant receives electric service on a residential rate ▪ Participant has an active service agreement with PG&E ▪ Participant has a PG&E SmartMeter ▪ Participant is not simultaneously enrolled in another supply-side demand response program offered by PG&E, third party DR provider (DRP), Community Choice Aggregator (CCA), or in ELRP sub-groups A.4 or A.5 ▪ Participant is not an electric customer of a Community Choice Aggregator who has opted out of being included in the Pilot
B.1	A third-party DRP with a market-integrated PDR resource is eligible to participate in ELRP.
B.2	A third-party CBP Aggregator with a market-integrated PDR resource is eligible to participate in ELRP. An account is only eligible to participate in ELRP if the service account has been nominated and bid during the ELRP operating month.

2.2 STUDY RESEARCH QUESTIONS

Table 2-2 summarizes the key research questions for the ELRP program.

Table 2-2: 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 does weather influence the magnitude of demand response?
3	How do load impacts differ for customers in each subgroup (Group A and Group B subgroups) during PY 2023?
4	What are the ex ante load reduction capabilities for 1-in-2 and 1-in-10 weather conditions? And how well do those align with ex post results?
5	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. Was the introduction of the ELRP program the primary cause of a customer's change in energy usage or were there other factors involved? To estimate a change in energy consumption, it is necessary to estimate what that 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 a combination of difference-in-differences with matched controls and individual customer regressions. Figure 2-1 summarizes the selection framework used to determine the appropriate method for each site, using subgroup A.1 as an example. Most sites utilize a difference-in-difference model, except for in cases where there were not enough sites in a given segment (customer size and subLAP) or for sites with an annual peak above 200 kW and daily usage patterns which exhibited substantial statistical noise (CVRMSE[3] above 0.25).

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[3] Coefficient of the Variation of the Root Mean Square Error: RMSE is the average distance between modeled and observed usage. CVRMSE reflects the relative size of the errors modeled for each site, normalized for the magnitude of each site's energy usage.

Figure 2-1: Ex Post Methodology Selection Framework

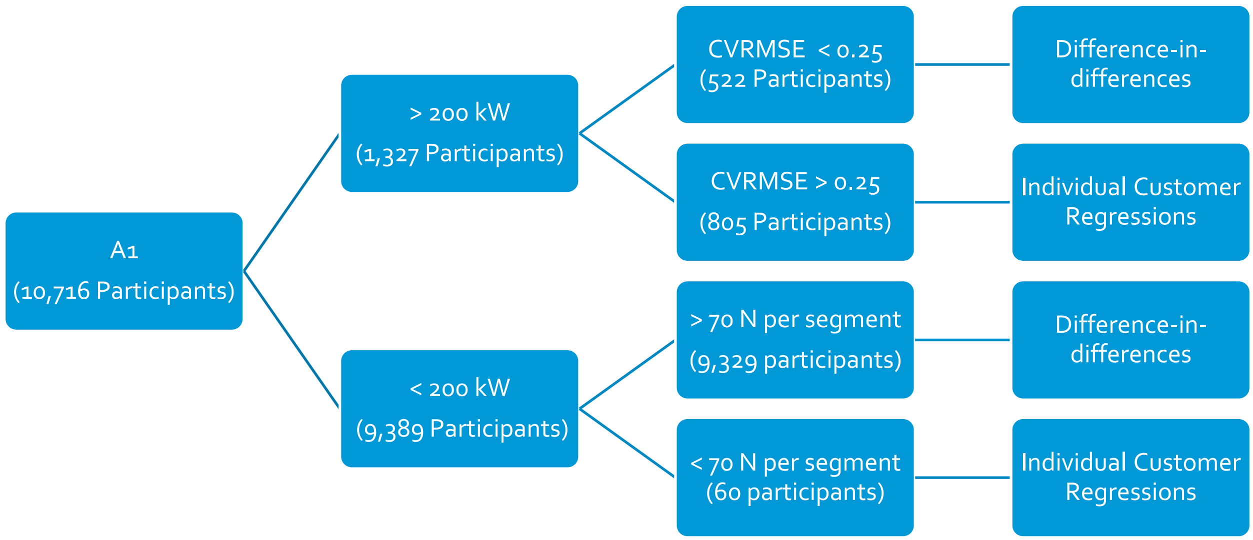


Table 2-3 summarizes the approach or approaches used for each subgroup. Note that for some subgroups a combination of methods was used. Additionally, no ex-post evaluation methodologies were applicable to subgroup A.6 since this subgroup was not dispatched in PY 2023. However, if events had been called, difference-in-differences would have been used.

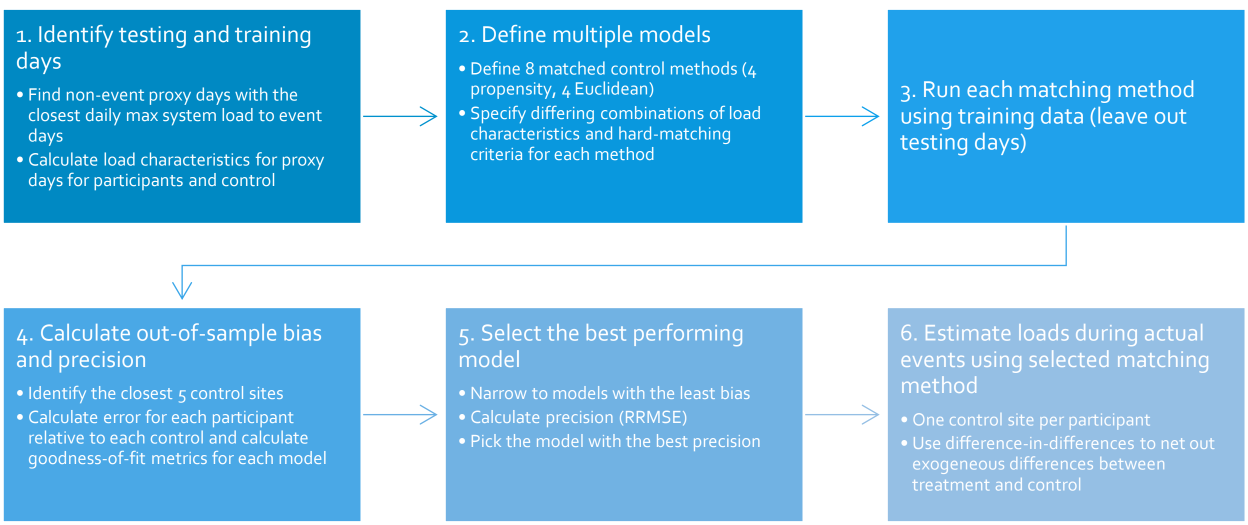
Table 2-3: Evaluation Methodology Used by Subgroup

ELRP Group	Individual customer regressions	Difference-in-differences
A.1	✓	✓
A.1-BIP	✓	
A.2-BIP	✓	
A.4		✓
A.5	✓	
A.6	N/A	N/A
B.2	✓	✓

Site-specific models for individual customer regressions were selected among dozens of potential specifications, which included synthetic controls[4] using one or more matched control site to help control for factors outside of the ELRP events. Similarly, the difference-in-differences approach used a matched control group to net out changes in energy usage patterns not due to the ELRP events. As such, regardless of evaluation methodology, each participant site was matched to one or more non-participant using a matching tournament where match quality was compared across eight different matching models to identify the best performing model.

Figure 2-2 summarizes the process used to select matched controls for the difference-in-difference analyses and synthetic controls for the individual customer regressions. To identify the control pool sites that best matched each participant site's energy use patterns on event-like, proxy days (similar in weather and system conditions to event days), eight matching methods were tested. These methods included different matching algorithms (e.g. Euclidean and propensity matching) and different site characteristics. Matching methods included different combinations of proxy day load characteristics such as load factor, load shape, and weather sensitivity. Control candidates were also "hard-matched" on subLAP, net metering status, and size bin[5].

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



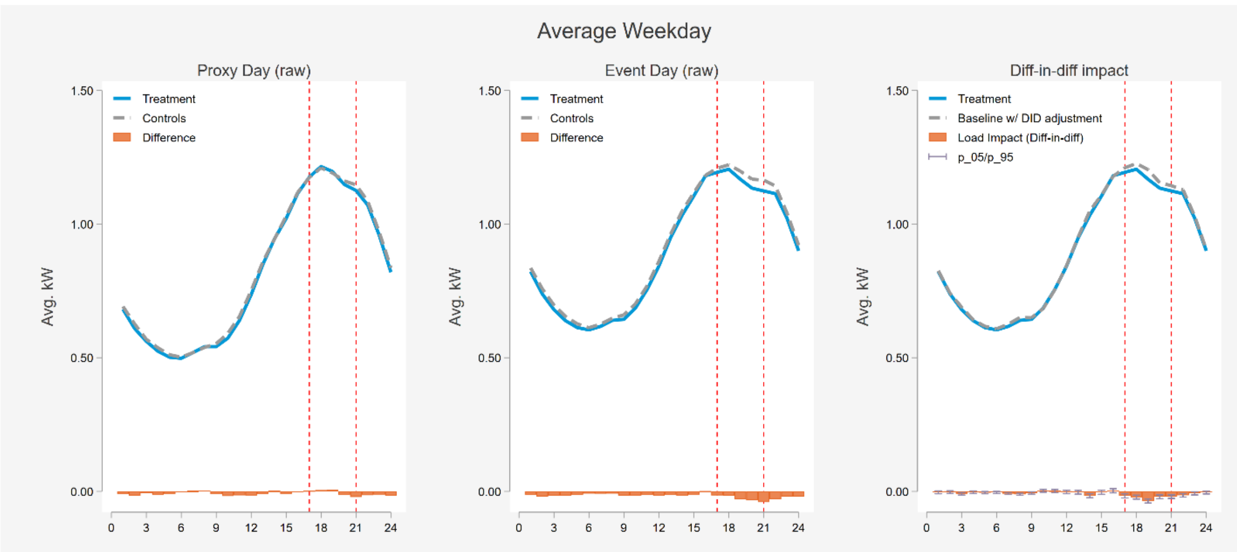
[4] The functional form of a regression with synthetic controls differs from a panel difference in difference regression in that usage for the control or controls are specified as right hand predictor variables. Additional detailed are available in the Appendix

[5] Bins were constructed using average usage on event-like, proxy days. For solar customers, bins were constructed based on system size.

Internal

As described above, difference-in-differences with matched controls was the primary evaluation methodology used, except in cases where there were few sites or large sites with noisy load patterns[6]. Figure 2-3 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 and 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-differences impact.

Figure 2-3: Difference-in-Differences Calculation Example



In cases where a difference-in-differences approach was not deemed appropriate due to insufficient sample size or for large sites with noisy loads, site-specific individual customer regression models were selected using another out of sample tournament to select the most accurate regression model specification for each participant site. Synthetic controls were considered in this tournament, including inclusion of an industry profile based on NAICS code and inclusion of solar irradiance. A variety of

[6] Out of sample testing was used to calculate RRMSE and other bias and fit metrics to compare across multiple pooled methods (average customer regressions and panel regressions). Based on this testing, difference-in-differences was determined to outperform or at least be comparable in robustness to the other methods. In contrast to the pooled regression-based methods, difference-in-difference has the advantage of enabling segmentation of results (by size, subLAP, industry, solar status, etc.) without the need to run additional regressions while ensuring that segment results add up to group totals.

within subjects lagged loads (1 day, 1 week, 2 weeks) were also considered. To implement out of sample testing, the top 50 system load days, excluding event days, were randomly divided into testing and training datasets. Bias and fit metrics were calculated using the testing dataset and the model with the best fit (lowest Root Mean Squared Error) was selected among models with the least bias (Mean Absolute Error[7]). Site specific load impacts were estimated with using the winning model for each site.

Site specific regression models were selected from 120 different possible specifications across the following parameters:

- Inclusion of an industry profile constructed of loads for other similar large commercial and industrial customers[8]
- Inclusion of local solar irradiance data[9]
- Number of control sites[10]
- Lags of load data[11]

Figure 2-4 shows the different model parameters that were included in the site-specific model tournament and the number of sites[12] for which each parameter was included in the winning model. The wide spread across parameters indicates that it was important to allow for individually tailored models to be selected for each participating site.

[7] MAE was used rather that Mean Average Percent Error (MAPE) to ensure robustness for sites with loads very close to zero, common for sites with solar or other generation.
[8] Selected from granular load profiles within climate zone and industry segment constructed and maintained by Demand Side Analytics for PG&E for the population NMEC settlement validation purposes for the Summer Reliability Program.
[9] Specific to the weather station nearest to the participant.
[10] Ranges from 0 to 5, selected using the out of sample match selection process.
[11] Lags were designed to capture the tendency of large commercial and industrial customers to operate on daily, weekly, or bi-weekly schedules irrespective of weather or time of year.
[12] Shown for the 1,536 sites across groups for which individual customer regressions were selected.

Figure 2-4: Modeling Parameters Tested and Inclusion in Best Performing Site Specific Models

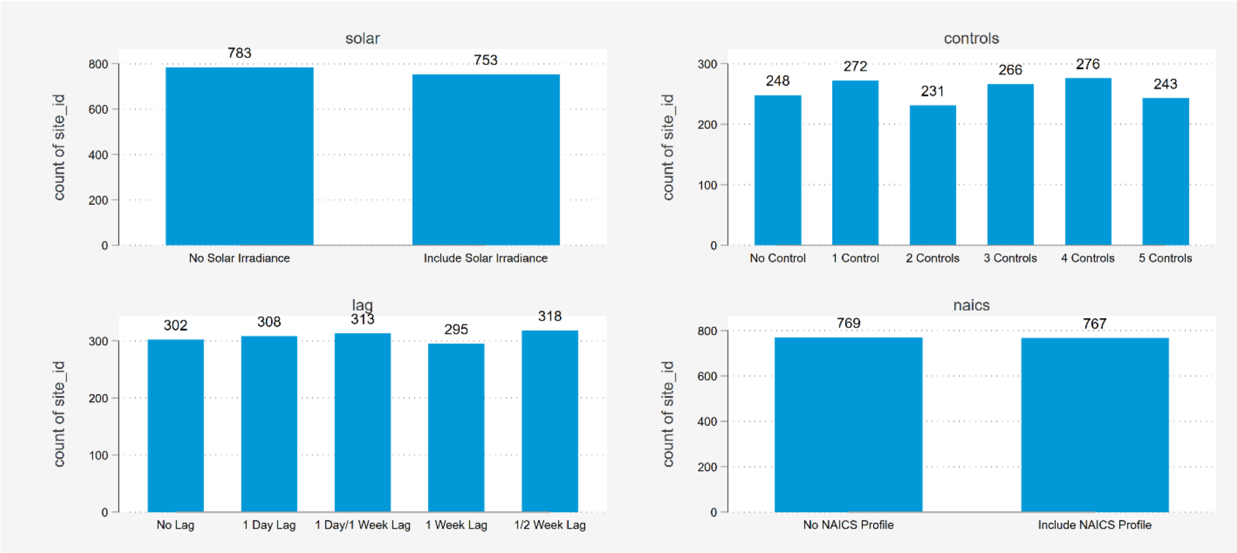


Table 2-4 summarizes the data sources, segmentation, and estimation methods used for each program. The segmentation was defined in advance of the analysis and is of particular importance because the evaluation used a bottom-up approach to estimate impacts to ensure that aggregate impacts across segments 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. Within each ELRP subgroup, the segmentation differentiated customers who were expected to deliver greater demand reductions– such as customers in the inland climate zone where cooling loads are higher– from customers who were expected to deliver lower demand reductions. For non-residential subgroups, customer size was also used. Additional segments were analyzed, after the fact, as part of exploratory analysis, but the core results presented are based on the segmentation detailed below.

Table 2-4: Evaluation Methods

Evaluation Element	ELRP A.1, A.2, A.3, A.4, A.5, B.2
Data sources / samples	▪ All event season data for the past program year for ✓ All 11,121 Non-Residential ELRP participant sites, all 5,805 A4 participant sites, and a sample of 74,118 A6 participant sites ✓ a control pool of 55k commercial non-participants and 2.5k non-participant residential sites with battery storage
Segmentation	▪ ELRP Subgroup ▪ SubLAP ▪ Size (non-residential groups only, Small, Medium, Large based on rate size)
Estimation method	▪ Primary method: difference-in-differences with matched controls ▪ Secondary method: Site specific regression models with synthetic controls

Evaluation Element	ELRP A.1, A.2, A.3, A.4, A.5, B.2
(Ex-post)	○ Applied in cases where there were few sites within a segment or large sites with noisy load patterns
Estimation method (Ex-ante)	▪ Top-down enrollment model based on PY 2023 enrollment levels, historic enrollment data, and program manager expectations ▪ Load reductions are assumed to be a function of curtailment of weather sensitive load except for exporting subgroups (A.3, A.4, A.5) for which reductions are the same for all weather specifications

3 ELRP EVENT DAY IMPACTS

Emergency Load Reduction Program (ELRP) participant sites receive day ahead or day-of event notifications via email and phone. The A.4 subgroup participants receive dispatch signals sent to their battery storage devices installed on the premises.

3.1 EVENT CHARACTERISTICS

Event impacts were assessed by site (premise and service point combination). While the modeling was performed individually for each site, results are reported by ELRP subgroup, summarized in Table 3-1. This table also summarizes the number of sample sites used for the ex post event analysis once data cleaning was completed, as well as the total number of sites enrolled during the PY 2023 event season (the first event was called on July 20 and the last on September 27). For A.6 a subset of the large participant population was sampled. For the other subgroups the number of sites in the ex post analysis may be slightly smaller than the total number of sites, due to the removal of sites with incomplete data, with outages on event days, and for which an adequate matched control could not be found. The sampled sites for A.6 were designed to be representative of the large program population, although there was no ex post analysis for this group in PY 2023 due to lack of events.

Table 3-1: Participant Populations (Avg Weekday Event)

ELRP Group	Sector(s)	Total sites	Sites in analysis*
A.1	Non-Residential	10,474	10,377
A.1BIP	Non-Residential	14	9
A.2BIP	Non-Residential	29	25
A.4	Non-Residential & Residential	6,158	6,158
A.5	Non-Residential	3	3
A.6	Residential	1,800,806	74,118
B.2	Non-Residential	601	578
Total		**1,818,085**	**91,268**

*Excludes a few sites without complete data. For A.6 reflect sites sampled for the analysis

Table 3-2 shows the nine PY 2023 ELRP event days and the PG&E system peak load on each day. While event dispatch dates and hours were the same for most non-residential subgroups and events in July, the August and September events were typically called for a few specific subgroups on specific hours. All eleven events occurred on weekdays, and none occurred on weekends or holidays. No events were called for subgroup A.6 in PY 2023.

Table 3-2: ELRP Events in 2023

Event date	Day of week	Event window	A.1	A.1-BIP	A.2-BIP	A.4	A.5	A.6	B.2	Max PG&E system load (MW)
7/20/2023	Thursday	8 to 9 pm	✓	✓	✓	✓	✓		✓	18,112
7/25/2023	Tuesday	8 to 9 pm	✓	✓	✓	✓	✓		✓	18,054
7/26/2023	Wednesday	6 to 9 pm	✓	✓	✓	✓	✓		✓	17,379
8/28/2023	Monday	6 to 9 pm			✓	✓	✓			17,008
8/29/2023	Tuesday	4 to 9 pm				✓	✓			16,619
8/30/2023	Wednesday	6 to 9 pm				✓	✓			17,958
9/19/2023	Tuesday	6 to 8 pm			✓	✓	✓			13,997
9/26/2023	Tuesday	4 to 9 pm					✓			13,606
9/27/2023	Wednesday	4 to 9 pm					✓			13,701

*Groups A.4 and A.5 called from 5 to 9 pm

Shaded rows indicate dates on which BIP were called.

3.1.1 Notification Success

As program year 2023 did not face emergency reliability conditions and grid capacity constraints, events were called in response to CAISO's Energy Emergency Alert (EEA) Watch and EEA 1 dispatches as well as system tests. The majority of participants were notified on the day-of and notifications were delivered closely to the event. This circumstance is in stark contrast to program year 2022, which was an extremely hot summer where EEA2, EEA 3 and FlexAlerts were called and ELRP participants were given more advanced notice. Figure 3-1 illustrates the average number of hours from the notification delivery to the event dispatch. The July 20th and July 25th event notifications were delivered after the event commenced for all subgroups, while participants were notified a few hours prior to the July 26th event. These were the only events called within the A1, A1-BIP, and B2 subgroups. On the remaining event days, in the other subgroups, participants were notified over 24 hours prior to the event dispatch.

Figure 3-1: Time from Notification Delivery to ELRP Event Dispatch

3.2 DATA SOURCES AND ANALYSIS METHOD

Table 3-3 summarizes the five data sources used to conduct the Non-Residential and Residential ELRP event impact analysis. The analysis was performed 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, the characteristic definitions used to build segments were consistent across analyses.

Table 3-3: Non-Residential and Residential ELRP Event Impact Evaluation Data Sources

Source	Comments
Hourly interval data	▪ Summer 2023 ▪ All analysis done by site (service account ID-service point ID pair)
Outage information	▪ PSPS and emergency outage data details which customers and what timeframes were impacted by outages
Customer characteristics	▪ Non-residential treatment: 11,121 customer sites ▪ Residential treatment: 5,805 A.4 sites, 74,118 A.6 sites ▪ Non-residential controls: 55k non-residential sites ▪ A4 controls: 2.5k residential sites with battery storage ▪ NEM status, subLAP used in matched control selection

Source	Comments
	▪ NAICS codes for development of industry profiles
PG&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 weather sensitivity for treatment and control pool sites, used as a matching criteria ▪ Solar irradiance considered for site specific regression model selection

The primary analysis method was difference-in-differences with matched controls. Site-specific individual regression models with synthetic controls were used in cases where there were too few participant sites in a segment or for very large sites (peak load above 200 kW) with noisy daily load patterns (CVRMSE above 0.25). An out of sample tournament was used to select a matching model for each subgroup. Matches were one of multiple controls used in the regression models. A winning distance matching model was selected for each subgroup. These winning models were used to select five matches for each of the ELRP participant sites among the appropriate control candidate pool, which is comprised of sites not enrolled in other DR programs because it may influence energy use and renders a customer ineligible for ELRP[13].

Once the matches were selected for each participant, the difference-in-differences model was used to assess impacts and standard errors for each event and each study segment, using the top match for each site. For sites requiring individual customer regressions, an out of sample tournament was used to select site specific regression models among dozens of possible specifications across 4 parameters: industry profiles, solar irradiance, up to five synthetic controls (selected in the tournament described above), and lagged participant site loads.

3.3 EX POST LOAD IMPACTS

3.3.1 ELRP GROUP A.1 IMPACTS BY EVENT

Group A.1 is designated for non-residential customers that are not participating in DR programs. It is currently the largest ELRP subgroup by far with over 10,000 participating sites. There were three events called for subgroup A.1 in PY 2023, across a variety of durations and start times. Table 3-4 summarizes the load reductions and participant weighted event temperatures for ELRP A.1 sites each event and for

[13] For the B2 subgroup, which is explicitly designed for dual participation with CBP, controls were pulled from the same pool of non-DR participants.

the average weekday event. In the tables, the bars show a visual comparison of the reductions that are numerically labeled on the left of the bars.

A.1 showed no statistically significant event impacts. One possible reason for this finding is that for the July 20th and 25th events no advance event notification was given and for the July 26th event only a few hours' notice was given ahead of dispatch, which did not give participants sufficient time to shed load. Table 3-4 also summarizes the number of sites enrolled and analyzed for each event day. A participant site needed to have data available both for the event day and the relevant proxy day, as well as have found a matched control, to be included in the estimate for a given event.

Table 3-4: ELRP A.1 Event Reductions

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post) Aggregate (MW)	% Reduction	Average Site (kW)	Significant (90% CI)	Significant (95% CI)
7/20/2023	8 to 9 pm	89.7	10,438	6.24	1.0%	0.60	No	No
7/25/2023	8 to 9 pm	88.9	10,469	-3.99	-0.6%	-0.38	No	No
7/26/2023	6 to 9 pm	91.1	10,474	11.28	1.8%	1.08	No	No
Avg Weekday 8-9pm	**8 to 9 pm**	**89.3**	**10,454**	**1.52**	**0.2%**	**0.15**	**No**	**No**
Avg Weekday 6-9pm	**6 to 9 pm**	**91.1**	**10,474**	**11.28**	**1.8%**	**1.08**	**No**	**No**
Avg Weekday (any)	**6 to 9 pm**	**90.3**	**10,460**	**5.03**	**0.8%**	**0.48**	**No**	**No**

3.3.2 ELRP Group A.1-BIP Impacts by Event

Group A.1-BIP is designated for non-residential, BIP customers and contains less than 10 participants. There were three events called for subgroup A.1-BIP in PY 2023, across a variety of durations and start times. Table 3-5 summarizes the load reductions and participant weighted event temperatures for ELRP A.1-BIP sites during each event and for the average weekday event. In the tables, the bars show a visual comparison of the reductions that are numerically labeled on the left of the bars.

[redacted]

Table 3-5: ELRP A.1-BIP Event Reductions

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post) Aggregate (MW)	% Reduction	Average Site (kW)	Significant (90% CI)	Significant (95% CI)
7/20/2023	8 to 9 pm	71.5	13	[redacted]				
7/25/2023	8 to 9 pm	74.2	13					
7/26/2023	6 to 9 pm	72.6	13					
Avg Weekday 8-9pm	**8 to 9 pm**	**72.9**	**13**					
Avg Weekday 6-9pm	**6 to 9 pm**	**72.6**	**13**					
Avg Weekday (any)	**6 to 9 pm**	**72.8**	**13**					

3.3.3 ELRP Group A.2-BIP Impacts by Event

Group A. 2-BIP is designated for non-residential, BIP aggregators. There were five events called for subgroup A.2-BIP in PY 2023, across a variety of durations and start times. Table 3-6 summarizes the load reductions and participant weighted event temperatures for ELRP A.2-BIP sites during each event and for the average weekday event. In the tables, the bars show a visual comparison of the reductions that are numerically labeled on the left of the bars.

[redacted]

Table 3-6: ELRP Group A.2-BIP Event Reductions

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post) Aggregate (MW)	% Reduction	Average Site (kW)	Significant (90% CI)	Significant (95% CI)
7/20/2023	8 to 9 pm	91.3	29	[redacted]				
7/25/2023	8 to 9 pm	89.8	29					
7/26/2023	6 to 9 pm	92.3	29					
8/28/2023	6 to 9 pm	89.8	29					
9/19/2023	6 to 8 pm	79.5	29					
Avg Weekday 8-9pm	**8 to 9 pm**	**90.6**	**29**					
Avg Weekday 6-9pm	**6 to 9 pm**	**91.0**	**29**					
Avg Weekday (any)	**6 to 9 pm**	**88.5**	**29**					

3.3.4 ELRP Group A.4 Impacts by Event

Group A.4 is designated for aggregators managing a behind the meter virtual power plant (VPP) aggregation of residential or non-residential customers. In PY 2023, there were over 5,000 residential participant sites. There were seven events called for subgroup A.4 in PY 2023, across a variety of durations and start times. Both the individual event days and the average weekday event reductions in Table 3-7 were significant and meaningful, unlike the other subgroups in PY 2023. In the tables, the bars show a visual comparison of the reductions that are numerically labeled on the left of the bars.

Aggregate reductions for significant events range from 11.12 MW (August 29th) to 24.53 MW (July 25th). No clear correlation between weather conditions, event window, and load reductions is evident. This makes sense conceptually since A.4 load reductions are typically only dependent on battery capacity. Significance was not correlated with event temperature and all events produced statistically significant load reductions.

Table 3-7: ELRP Group A.4 Event Reductions

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post)			Significant (90% CI)	Significant (95% CI)
				Aggregate (MW)	% Reduction	Average Site (kW)		
7/20/2023	8 to 9 pm	74.8	5,773	21.83	387.0%	3.77	Yes	Yes
7/25/2023	8 to 9 pm	75.8	5,794	24.53	526.1%	4.23	Yes	Yes
7/26/2023	6 to 9 pm	73.9	5,794	22.28	1291.9%	3.84	Yes	Yes
8/28/2023	6 to 9 pm	77.0	6,085	21.11	701.4%	3.46	Yes	Yes
8/29/2023	4 to 9 pm	81.6	6,084	11.12	-558.3%	1.82	Yes	Yes
8/30/2023	6 to 9 pm	84.3	6,103	20.87	379.7%	3.41	Yes	Yes
9/19/2023	5 to 9 pm	69.7	6,146	15.85	4533.8%	2.57	Yes	Yes
Avg Weekday 8-9pm	**8 to 9 pm**	**75.3**	**5,796**	**23.23**	**450.0%**	**4.00**	**Yes**	**Yes**
Avg Weekday 6-9pm	**6 to 9 pm**	**78.5**	**6,108**	**21.78**	**620.5%**	**3.56**	**Yes**	**Yes**
Avg Weekday (any)	**4 to 9 pm**	**77.1**	**6,158**	**18.13**	**1098.6%**	**2.96**	**Yes**	**Yes**

3.3.5 ELRP Group A.5 Impacts by Event

Group A.5 is designated for non-residential vehicle-grid integration (VGI) aggregators not participating in DR programs and was comprised of three participating sites in PY 2023. There were nine events called for subgroup A.5 in PY 2023, across a variety of durations and start times. Table 3-8 summarizes the load reductions and participant weighted event temperatures for ELRP A.5 sites during each event and for the average weekday event. In the tables, the bars show a visual comparison of the reductions that are numerically labeled on the left of the bars.

[redacted]

Table 3-8: ELRP Group A.5 Event Reductions

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post) Aggregate (MW)	% Reduction	Average Site (kW)	Significant (90% CI)	Significant (95% CI)
7/20/2023	8 to 9 pm	80.0	3	[redacted]				
7/25/2023	8 to 9 pm	79.7	3	[redacted]				
7/26/2023	6 to 9 pm	78.6	3	[redacted]				
8/28/2023	6 to 9 pm	81.2	3	[redacted]				
8/29/2023	4 to 9 pm	81.8	3	[redacted]				
8/30/2023	6 to 9 pm	86.1	3	[redacted]				
9/19/2023	5 to 9 pm	73.8	3	[redacted]				
9/26/2023	4 to 9 pm	73.6	3	[redacted]				
9/27/2023	4 to 9 pm	74.8	3	[redacted]				
Avg Weekday 8-9pm	**8 to 9 pm**	**79.8**	**3**	[redacted]				
Avg Weekday 6-9pm	**6 to 9 pm**	**82.0**	**3**	[redacted]				
Avg Weekday (any)	**4 to 9 pm**	**78.8**	**3**	[redacted]				

3.3.6 ELRP Group A.6 Impacts by Event

There were no events called for Group A.6 during PY 2023, so ex post impacts cannot be evaluated for this group.

3.3.7 ELRP Group B.2 Impacts by Event

Group B.2 is designated for IOU capacity bidding program (CBP) PDR resources and was comprised of 578 participating sites in PY 2023. There were three events called for subgroup B.2 in PY 2023, across a variety of durations and start times. Table 3-9 summarizes the load reductions and participant weighted event temperatures for ELRP B.2 sites during each event and for the average weekday event. In the tables, the bars show a visual comparison of the reductions that are numerically labeled on the left of the bars.

The average event reductions were not significant or meaningful, like most other subgroups in PY 2023.

Table 3-9: ELRP Group B.2 Event Reductions

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post) Aggregate (MW)	% Reduction	Average Site (kW)	Significant (90% CI)	Significant (95% CI)
7/20/2023	8 to 9 pm	82.6	601	-2.30	-3.3%	-3.83	No	No
7/25/2023	8 to 9 pm	82.5	601	-2.27	-3.2%	-3.77	No	No
7/26/2023	6 to 9 pm	83.5	601	-0.85	-1.2%	-1.42	No	No
Avg Weekday 8-9pm	**8 to 9 pm**	**82.6**	**601**	**-2.28**	**-3.2%**	**-3.80**	**No**	**No**
Avg Weekday 6-9pm	**6 to 9 pm**	**83.5**	**601**	**-0.85**	**-1.2%**	**-1.42**	**No**	**No**
Avg Weekday (any)	**6 to 9 pm**	**83.0**	**601**	**-1.82**	**-2.6%**	**-3.04**	**No**	**No**

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 as the reductions for a standardized set of weather conditions.

3.4.1 RELATIONSHIP OF CUSTOMER LOADS AND PERCENT REDUCTIONS TO WEATHER

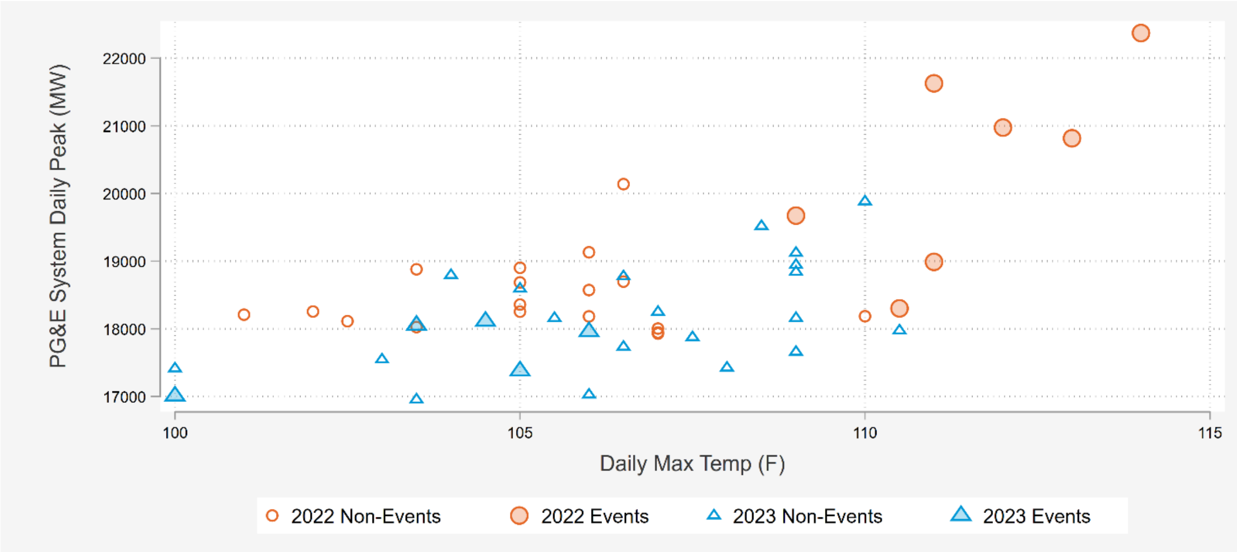
When developing the ex ante forecast it is important to ask two questions:

1. What are the most event relevant weather conditions for an emergency program such as ELRP?
2. How do observed impacts vary under those weather conditions?

The first question is important for determining which historical impacts should be used for developing the ex ante forecast. PY 2023 ex post impacts were largely not significant across the non-residential subgroups. This stands in contrast to ex post results for PY 2022 which yielded positive, significant reductions. In PY 2023, A.1 retained its largest participants and has a similar set of participants as in PY 2022, so the difference cannot be explained by changes in participation. Instead, the explanation likely lies in other differences between PY 2022 and PY 2023, notably the weather conditions and resulting effects on dispatch.

Figure 3-2 compares system loads and maximum daily temperatures for the top 25 system load days for both years (2022 in orange and 2023 in blue), demonstrating that peak system loads were about 2,000 MW higher in 2022 and peak temperatures about 5 to 10 degrees higher. This underscores the fundamental differences between the two years. PY 2022 was an extreme weather year which saw not only ten ELRP events dispatched, most within the same week, but also a statewide phone notification sent from the California Office of Emergency Services on September 6, 2022. There was a relatively high level of awareness of the statewide emergency conditions, and this coincided with reductions. In contrast, there were no comparable emergency conditions in PY 2023. Of the three ELRP events called for all non-residential subgroups, two were single hour events dispatched with an hour or less of advance notice and the third was dispatched with day-of notice. This contrasts to the day ahead notice provided for the PY 2022 events, also a reflection of the extreme sustained conditions experienced in PY 2022.

Figure 3-2: Summer System Loads and Max Daily Temperatures, 2022 and 2023

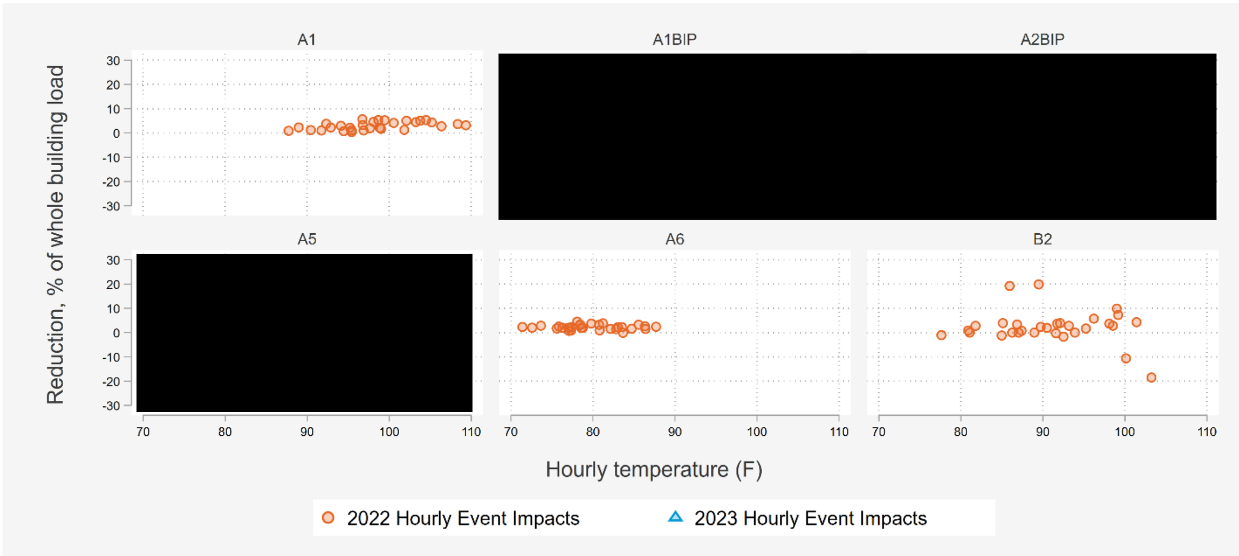


For these reasons, the impacts observed in PY 2022 seem more reflective of what could be expected under emergency conditions. Because ELRP is an emergency program, the PY 2023 ex ante forecast applied the emergency condition reductions from PY 2022 rather than the reductions observed under the much milder PY 2023 conditions.

The second question which should be asked when developing an ex ante weather model is how observed impacts vary under those weather conditions. Figure 3-3 shows the hourly percent reductions for historical weekday events as a function of hourly temperatures for sites in each ELRP subgroup[14]. [redacted]

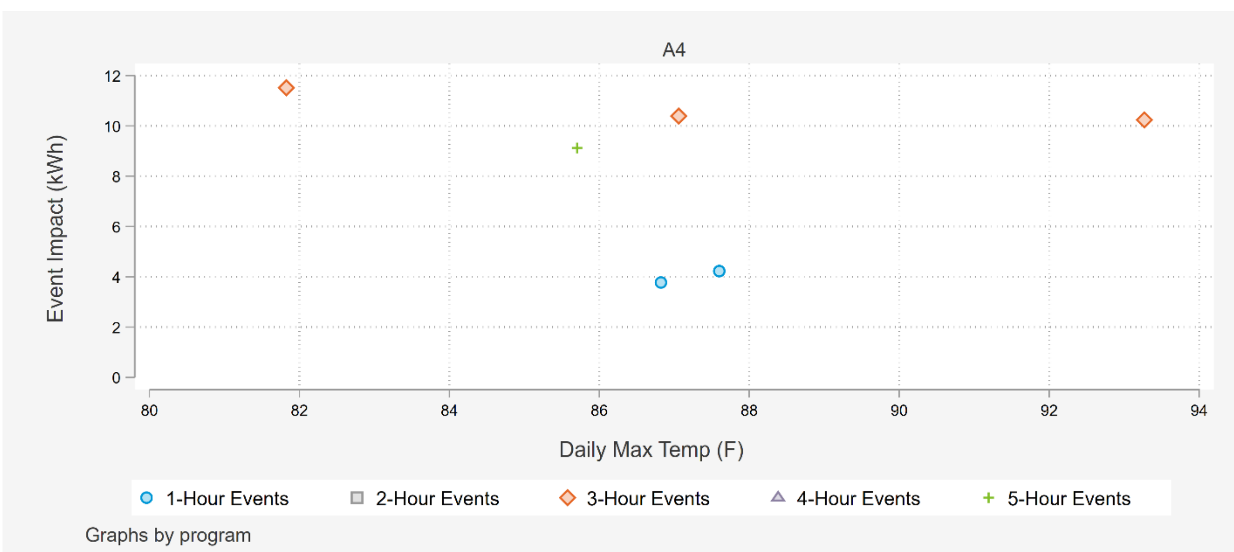
[14] Impacts that are not statistically significant have been recoded to zero.

Figure 3-3: ELRP Hourly Reductions and Temperatures



For the A.4 subgroup, which is comprised of battery storage responding to dispatch signals, impacts can be assumed to be a function of the battery capacity made available by participants. Figure 3-4 shows the total kWh reduction for the average site for the two A.4 events. This is essentially the portion of the battery not reserved for on-site back-up. Assessment of these PY 2023 events show no clear correlation between kWh reductions and weather. While event kWh impacts seem to be lower for the 1 hour events (on July 20 and 25), there were also dispatch notification delays for those events so there is insufficient data to conclude if the lower reductions are a function of the shorter duration or of the dispatch signaling. This assumption should continue to be assessed in future program years.

Figure 3-4: PY 2023 ELRP A4 Event kWh Reductions and Temperatures



3.4.2 PROGRAM SPECIFIC AND PORTFOLIO ADJUSTED IMPACTS

Program specific and portfolio adjusted impacts are developed for each subgroup. The fundamental difference that necessitates having these two sets of results is grounded in the ability of customers to participate in more than one energy saving program. Dual enrollments make proper attribution of savings estimates essential, to avoid double-counting. Ex post results are properly attributed by calculating the incremental impacts, or the load reduction beyond what was predicted or committed on dually called event hours. Modelling for ex ante is based solely on these incremental impacts.

Program specific ex ante estimates are the predicted savings generated by the population on days where only ELRP is called. Portfolio adjusted ex ante estimates are the population's incremental savings on days where eligible participants are called under both ELRP and the dually enrolled program. This distinction is analyzed since it can impact how participants respond to being called for an event.

Table 3-10 defines the dual enrolled programs for consideration in each subgroup.

Table 3-10: Eligible Dually Enrolled Programs for Ex Ante Considerations

ELRP Program	A1	A1BIP	A2BIP	A4	A5	A6	B2
Eligible Dually Enrolled Program	Peak Day Pricing	BIP	BIP	SmartAC	SmartAC	SmartRate	Capacity Bidding Program

If there are no dual enrollments allowed or there were no dual events in a given season, the program impacts will equal the portfolio impacts.

3.4.3 EX ANTE ENROLLMENT FORECAST

To derive the aggregate forecast and reference loads, percent impacts per customer are scaled to the site population expected to be enrolled in each planning year. Table 3-11 summarizes the annual enrollments forecast for each subgroup through the approval year for each subgroup, e.g. 2025 for subgroup A.6 and 2027 for all other subgroups.

Table 3-11: Participant Enrollment Forecast

Year	A.1	A.1-BIP	A.2-BIP	A.4	A.5	A.6	B.2	Total
2023	10,394	13	18	6,125	3	1,610,556	559	1,627,668
2024	11,770	13	18	6,944	3	1,493,633	700	1,513,081
2025	13,502	13	18	7,985	3	1,261,526	700	1,283,747
2026	15,035	13	18	8,681	3	0	700	24,450
2027	16,384	13	18	9,185	3	0	700	26,303

PG&E developed the ELRP enrollment forecast that was used to scale the ex ante impacts. The enrollment forecast reflects current enrollment in PY 2023. For subgroups A.1-BIP, A.2-BIP, A.5, and B.2

enrollments are expected to remain flat and end after 2027. Subgroups A.1 and A.4 are expected to grow until 2027. Subgroup A.6 enrollment is forecasted to decline until 2025 when it will be either renewed or discontinued.

3.4.4 ELRP Group A.1 Ex Ante Load Impacts

Group A.1 is designated for non-residential customers not participating in DR programs and is currently the largest ELRP subgroup by far with over 10,000 participating sites. Table 3-12 summarizes the portfolio adjusted ex ante demand reduction capability by forecast year for different planning conditions. Table 3-13 shows the same for program specific impacts. The tables reflect dispatchable demand reductions available from 4 pm to 9 pm under August monthly peaking conditions for 1-in-2 and 1-in-10 weather conditions, which align with the planning conditions used for resource adequacy attribution. The ex post analysis showed no clear trend in percent load reductions relative to weather patterns so ex ante reductions are assumed to vary only as a function of the reference load. The static average percent reduction in each event hour is applied to this reference load.

This load impact forecast reflects reductions observed during PY 2022 emergency conditions. Enrollments are assumed to grow through the last year of ELRP approval in 2027.

Table 3-12: Group A.1 Portfolio Adjusted Impacts for August Monthly Peak Day (MW)

Year	Sites	CAISO		PG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2023	10,394	21.88	22.72	22.56	23.33
2024	11,770	25.32	26.58	26.26	27.09
2025	13,502	29.20	30.65	30.28	31.23
2026	15,035	32.60	34.22	33.81	34.87
2027	16,384	35.58	37.35	36.91	38.06

Table 3-13: Group A.1 Program Specific Impacts for August Monthly Peak Day (MW)

Year	Sites	CAISO		PG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2023	10,438	21.95	22.79	22.63	23.41
2024	11,770	25.32	26.58	26.26	27.09
2025	13,502	29.20	30.65	30.28	31.23
2026	15,035	32.60	34.22	33.81	34.87
2027	16,384	35.58	37.35	36.91	38.06

3.4.5 ELRP Group A.1-BIP Ex Ante Load Impacts

Group A.1-BIP is designated for non-residential BIP customers. Table 3-14 summarizes the portfolio adjusted ex ante demand reduction capability by forecast year for different planning conditions. Table 3-15 shows the same for program specific impacts. Program specific impacts are zero because A.1-BIP participants did not respond on ELRP event days that were not also BIP events in PY 2022. The tables reflect dispatchable demand reductions available from 4 pm to 9 pm under August monthly peaking conditions for 1-in-2 and 1-in-10 weather conditions, which align with the planning conditions used for resource adequacy attribution. The ex post analysis showed no clear trend in percent load reductions relative to weather patterns so ex ante reductions are assumed to vary only as a function of the reference load. The static average percent reduction in each event hour is applied to this reference load.

This load impact forecast reflects reductions observed during PY 2022 emergency conditions. Enrollments are assumed to stay flat through the last year of ELRP approval in 2027.

Table 3-14: Group A.1-BIP Portfolio Adjusted Impacts for August Monthly Peak Day (MW)

Year	Sites	CAISO		PG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2023	13	2.25	2.22	2.20	2.29
2024	13	4.89	4.91	4.88	5.14
2025	13	4.89	4.91	4.88	5.14
2026	13	4.89	4.91	4.88	5.14
2027	13	4.89	4.91	4.88	5.14

Table 3-15: Group A.1-BIP Program Specific Impacts for August Monthly Peak Day (MW)

Year	Sites	CAISO		PG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2023	13	0.00	0.00	0.00	0.00
2024	13	0.00	0.00	0.00	0.00
2025	13	0.00	0.00	0.00	0.00
2026	13	0.00	0.00	0.00	0.00
2027	13	0.00	0.00	0.00	0.00

3.4.6 ELRP Group A.2-BIP Ex Ante Load Impacts

Group A.2-BIP is designated for non-residential BIP aggregators. Table 3-16 summarizes the portfolio adjusted ex ante demand reduction capability by forecast year for different planning conditions. Table 3-17 shows the same for program specific impacts. Program specific impacts are zero because A.2-BIP participants did not respond on ELRP event days that were not also BIP events in PY 2022. The tables reflect dispatchable demand reductions available from 4 pm to 9 pm under August monthly peaking conditions for 1-in-2 and 1-in-10 weather conditions, which align with the planning conditions used for resource adequacy attribution. The ex post analysis showed no clear trend in percent load reductions relative to weather patterns so ex ante reductions are assumed to vary only as a function of the reference load. The static average percent reduction in each event hour is applied to this reference load.

This load impact forecast reflects reductions observed during PY 2022 emergency conditions. Enrollments are assumed to stay flat through the last year of ELRP approval in 2027.

Table 3-16: Group A.2-BIP Portfolio Adjusted Impacts for August Monthly Peak Day (MW)

Year	Sites	CAISO		PG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2023	18	2.37	2.43	2.41	2.44
2024	18	1.70	1.76	1.74	1.77
2025	18	1.70	1.76	1.74	1.77
2026	18	1.70	1.76	1.74	1.77
2027	18	1.70	1.76	1.74	1.77

Table 3-17: Group A.2-BIP Program Specific Impacts for August Monthly Peak Day (MW)

Year	Sites	CAISO		PG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2023	18	0.00	0.00	0.00	0.00
2024	18	0.00	0.00	0.00	0.00
2025	18	0.00	0.00	0.00	0.00
2026	18	0.00	0.00	0.00	0.00
2027	18	0.00	0.00	0.00	0.00

3.4.7 ELRP Group A.4 Ex Ante Load Impacts

Group A.4 is designated for Virtual Power Plant (VPP) aggregators of non-residential and residential battery storage. Table 3-18 summarizes the portfolio adjusted ex ante demand reduction capability by forecast year for different planning conditions. Table 3-19 shows the same for program specific impacts. The tables reflect dispatchable demand reductions available from 4 pm to 9 pm under August monthly peaking conditions for 1-in-2 and 1-in-10 weather conditions, which align with the planning conditions used for resource adequacy attribution. The ex post analysis showed no trend in reductions by weather patterns and are therefore assumed to not be not weather sensitive. Load reductions are instead assumed to be a function of the total kWh reduction delivered by the average site for the average event, not reductions in weather sensitive loads. To derive expected impacts average kWh delivered during the PY 2023 events is then divided by 3, to take into account the resource availability rules set to go into effect for PY2024.[15] Essentially, A.4 resources are required to provide three hours of reductions during the 4pm to 9pm availability window, so it is assumed that the kWh reductions will be spread evenly across three hours. The resulting average kWh per hour is applied to all five hours of the RA window.

Enrollments are assumed to grow through the last year of ELRP approval in 2027.

Table 3-18: Group A.4 Portfolio Adjusted Impacts for August Monthly Peak Day (MW)

Year	Sites	CAISO		PG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2023	6,125	17.37	17.37	17.37	17.37
2024	6,944	19.14	19.14	19.14	19.14
2025	7,985	22.01	22.01	22.01	22.01
2026	8,681	23.93	23.93	23.93	23.93
2027	9,185	25.32	25.32	25.32	25.32

Table 3-19: Group A.4 Program Specific Impacts for August Monthly Peak Day (MW)

Year	Sites	CAISO		PG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2023	6,125	17.37	17.37	17.37	17.37
2024	6,944	19.14	19.14	19.14	19.14
2025	7,985	22.01	22.01	22.01	22.01
2026	8,681	23.93	23.93	23.93	23.93
2027	9,185	25.32	25.32	25.32	25.32

3.4.8 ELRP Group A.5 Ex Ante Load Impacts

Group A.5 is designated for non-residential vehicle-grid integration (VGI) aggregators not participating in DR programs and was comprised of three participating sites in PY 2023. Table 3-20 summarizes the portfolio adjusted ex ante demand reduction capability by forecast year for different planning conditions. Table 3-21 shows the same for program specific impacts. The tables reflect dispatchable demand reductions available from 4 pm to 9 pm under August monthly peaking conditions for 1-in-2 and 1-in-10 weather conditions, which align with the planning conditions used for resource adequacy

[15] D.23-12-005 (521486520.PDF (ca.gov)) , section 11.1.9.1 page 142

attribution. [redacted]

[redacted] Enrollments are assumed to stay flat through the last year of ELRP approval in 2027.

Table 3-20: Group A.5 Portfolio Adjusted Impacts for August Monthly Peak Day (MW)

Year	Sites	CAISO		PG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2023	3	[redacted]	[redacted]	[redacted]	[redacted]
2024	3	[redacted]	[redacted]	[redacted]	[redacted]
2025	3	[redacted]	[redacted]	[redacted]	[redacted]
2026	3	[redacted]	[redacted]	[redacted]	[redacted]
2027	3	[redacted]	[redacted]	[redacted]	[redacted]

Table 3-21: Group A.5 Program Specific Impacts for August Monthly Peak Day (MW)

Year	Sites	CAISO		PG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2023	3	[redacted]	[redacted]	[redacted]	[redacted]
2024	3	[redacted]	[redacted]	[redacted]	[redacted]
2025	3	[redacted]	[redacted]	[redacted]	[redacted]
2026	3	[redacted]	[redacted]	[redacted]	[redacted]
2027	3	[redacted]	[redacted]	[redacted]	[redacted]

3.4.9 ELRP Group A.6 Ex Ante Load Impacts

Group A.6 is designated for residential customers not participating in DR programs and was comprised of approximately nearly 2 million participating sites in PY 2023. Table 3-22 summarizes the portfolio adjusted ex ante demand reduction capability by forecast year for different planning conditions. Table 3-23 shows the same for program specific impacts. The tables reflect dispatchable demand reductions available from 4 pm to 9 pm under August monthly peaking conditions for 1-in-2 and 1-in-10 weather conditions, which align with the planning conditions used for resource adequacy attribution. Since there were no A.6 events in PY 2023, impacts from PY 2022 were used to build the ex ante impact model. The ex post analysis showed no clear trend in percent load reductions relative to weather patterns so ex ante reductions are assumed to vary only as a function of the reference load. The static average percent reduction in each event hour is applied to this reference load. This calculation is performed for each eligibility group, since the reductions, reference loads, and forecasted enrollments all vary by eligibility group.

This load impact forecast reflects reductions observed during PY 2022 emergency conditions. Enrollments are assumed to wane through the last year of A.6 ELRP approval in 2025.

Table 3-22: Group A.6 Portfolio Adjusted Impacts for August Monthly Peak Day (MW)

Year	Sites	CAISO		PG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2023	1,610,556	42.26	52.52	50.21	56.63
2024	1,493,633	48.09	64.35	60.70	67.93
2025	1,261,526	42.91	57.45	54.19	60.62

Table 3-23: Group A.6 Program Specific Impacts for August Monthly Peak Day (MW)

Year	Sites	CAISO		PG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2023	1,610,556	46.04	55.93	53.75	59.90
2024	1,493,633	51.40	67.06	63.60	70.53
2025	1,261,526	45.11	58.96	55.89	61.99

3.4.10 ELRP Group B.2 Ex Ante Load Impacts

Group B.2 is designated for IOU capacity bidding (CBP) PDR resources. Table 3-24 summarizes the portfolio adjusted ex ante demand reduction capability by forecast year for different planning conditions. Table 3-25 shows the same for program specific impacts. Impacts on non-dual event days in PY 2022 were slightly higher than the incremental impacts on dual CBP event days, resulting in somewhat higher program specific impacts. The tables reflect dispatchable demand reductions available from 4 pm to 9 pm under August monthly peaking conditions for 1-in-2 and 1-in-10 weather conditions, which align with the planning conditions used for resource adequacy attribution. The ex post analysis showed no clear trend in percent load reductions relative to weather patterns so ex ante reductions are assumed to vary only as a function of the reference load. The static average percent reduction in each event hour is applied to this reference load.

This load impact forecast reflects reductions observed during PY 2022 emergency conditions. Enrollments are assumed to stay flat through the last year of ELRP approval in 2027.

Table 3-24: Group B.2 Portfolio Adjusted Impacts for August Monthly Peak Day (MW)

Year	Sites	CAISO		PG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2023	559	0.81	0.83	0.82	0.85
2024	700	0.98	1.00	1.00	1.02
2025	700	0.98	1.00	1.00	1.02
2026	700	0.98	1.00	1.00	1.02
2027	700	0.98	1.00	1.00	1.02

Table 3-25: Group B.2 Program Specific Impacts for August Monthly Peak Day (MW)

Year	Sites	CAISO		PG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2023	559	1.02	1.08	1.06	1.10
2024	700	1.22	1.29	1.27	1.31
2025	700	1.22	1.29	1.27	1.31
2026	700	1.22	1.29	1.27	1.31
2027	700	1.22	1.29	1.27	1.31

3.4.11 Comparison of Ex Post And Ex Ante Load Impacts

Table 3-26 compares the PY 2023 ex ante counterfactuals and demand reductions to the average across PY 2022 non-residential events. These were used to develop the PY 2023 ex ante forecast since the PY 2023 ex post results mostly represent random variation. In PY 2022 the average event was also called from 4 to 9pm but in PY 2023 shorter events were called. Ex ante results are shown for the 4pm to 9pm resource adequacy window and compared to the average PY2022 weekday event for the same time period, to ensure comparability of loads. In 2022, non-residential ELRP customers delivered 3.5% in load reductions (32.79 MW) for the average event which was also called from 4 to 9pm. Ex ante reductions for the 4 to 9pm resource adequacy window, which happened to align with the event window, were 3.9% and therefore similar to ex post reductions. Differences in ex ante and ex post counterfactual loads (Load without DR) are largely explained by the change in the enrollment population from PY 2022 ex post enrollment as compared to PY 2023 ex ante. Specifically, though there were more participants in PY 2023, a few very large PY 2022 participants did not participate in PY 2023. The PG&E and CAISO weather ex ante predictions are slightly different because ex ante reference loads are assumed to be weather sensitive. Percent impacts are equal across the two ex ante weather specifications because no weather trend was established for impacts.

Table 3-26: Non-Residential ELRP[16] Comparison of Ex Post and Ex Ante Load Impacts for 2023

Result Type	Day Type and Period	Sites	Load without DR (MW)	Load Reduction (MW)	% Reduction	Event Avg Temp (F)
Ex Post Avg. Weekday (PY 2022)	Resource Adequacy Period (4 to 9 pm)	7,426	937.27	32.79	3.5%	96.2
Ex ante PG&E (Portfolio Adjusted)	1-in-2 Weather August Peak (4 to 9 pm)	10,987	715.96	27.99	3.9%	91.7
Ex ante CAISO (Portfolio Adjusted)	1-in-2 Weather August Peak (4 to 9 pm)	10,987	684.96	27.30	4.0%	89.0

Table 3-27 compares the demand reductions from 2023 A.4 events. Results are shown for the 4pm to 9pm resource adequacy window and compared to the average PY2023 weekday event. ELRP A.4 customers delivered 10.87 MW in 2023 on average across the 4 to 9pm period which is shown here to facilitate comparison to the ex ante estimates. This corresponds to 54 MWh in total across the 5 hour window. To derive expected ex ante impacts, average MWh delivered during the PY2023 events is divided by 3, to take into account the resource availability rules set to go into effect for PY2024.[17] Essentially, A.4 resources are required to be to provide three hours of reductions during the 4pm to 9pm availability window, so it is assumed that the kWh reductions will be spread evenly across three hours. The resulting average MWh per hour is applied to all five hours of the RA window. The resulting ex ante impact is 17.37 MW per hour, or 52 MWh over three hours, which aligns well with the ex post result.

Table 3-27: A4 Battery ELRP Comparison of Ex Post and Ex Ante Load Impacts for 2023

Result Type	Day Type and Period	Sites	Load without DR (MW)	Load Reduction (MW)	% Reduction	Event Avg Temp (F)
Ex Post Avg. Weekday (PY 2023)	Resource Adequacy Period (4 to 9 pm)	6,108	-1.26	10.87	-864.7%	81.7

[16] A.1, A.1-BIP, A.2-BIP, A.5, B.2

[17] D.23-12-005 (521486520.PDF (ca.gov)) , section 11.1.9.1 page 142

Result Type	Day Type and Period	Sites	Load without DR (MW)	Load Reduction (MW)	% Reduction	Event Avg Temp (F)
Ex ante PG&E (Portfolio Adjusted)	1-in-2 Weather August Peak (4 to 9 pm)	6,125	0.04	17.37	42277.0%	83.3
Ex ante CAISO (Portfolio Adjusted)	1-in-2 Weather August Peak (4 to 9 pm)	6,125	-1.42	17.37	-1219.9%	81.8

Table 3-28 compares the demand reductions from 2022 A.6 events, since no events were called in PY 2023. Ex ante results are shown for the 4pm to 9pm resource adequacy window and compared to the loads and impacts for the average PY 2022 weekday event day, during the 4 to 9pm window which also corresponded to the event window. Loads, percent impacts, and enrollments are very similar between PY 2022 ex post and PY 2023 ex ante, with moderate differences due to a slight increase in enrollments in 2023, but also cooler 1-in-2 temperatures than those observed for PY 2022 events.

Table 3-28: A6 Residential ELRP Comparison of Ex Post and Ex Ante Load Impacts for 2023

Result Type	Day Type and Period	Sites	Load without DR (MW)	Load Reduction (MW)	% Reduction	Event Avg Temp (F)
Ex Post Avg. Weekday (PY 2022)	Resource Adequacy Period (4 to 9 pm)	1,517,305	2877.63	58.98	2.0%	93.2
Ex ante PG&E (Portfolio Adjusted)	1-in-2 Weather August Peak (4 to 9 pm)	1,610,556	2616.35	50.21	1.9%	85.5
Ex ante CAISO (Portfolio Adjusted)	1-in-2 Weather August Peak (4 to 9 pm)	1,610,556	2237.33	42.26	1.9%	83.4

3.4.12 Ex Ante Load Impact Slice-of-Day Tables

Table 3-29, Table 3-30, Table 3-31, Table 3-32, Table 3-33, Table 3-34, and Table 3-35 show the 2023 ex ante aggregate hourly impacts by ELRP Group for each month under PG&E 1-in-2 monthly peaking conditions. The tables are designed to enable the CPUC's Slice-of-Day Resource Adequacy requirements. Currently the ELRP pilot does not qualify for Resource Adequacy, but these tables reflect what the slice of day load impacts would look like if ELRP did qualify for Resource Adequacy. The estimated reductions are typically larger in the hotter summer months and smaller in the cooler winter months. For Group A.4, response to an event is flat across the five-hour Resource Adequacy window to reflect consistent battery discharge. For other groups, however, event response varies by hour.

Table 3-29: Group A.1 Slice of Day Table for Monthly Peak Day (Portfolio Adjusted 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	23.83	23.83	0.00	0.00	0.00	28.75	33.20	33.72	33.75	32.35	30.17	30.15
18	18.46	18.46	21.92	22.90	23.71	22.96	26.68	26.92	26.72	24.88	23.07	23.06
19	14.14	14.14	16.74	17.53	18.39	17.84	20.84	20.94	20.63	18.83	17.37	17.37
20	11.29	11.29	13.33	14.00	14.75	14.43	16.82	16.90	16.62	15.00	13.76	13.75
21	9.23	9.23	11.09	11.69	12.47	12.40	14.29	14.30	13.98	12.32	11.22	11.22
22	0.00	0.00	9.10	9.63	10.42	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 3-30: Group A.1-BIP Slice of Day Table for Monthly Peak Day (Portfolio Adjusted 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	2.50	2.50	0.00	0.00	0.00	2.33	2.46	2.45	2.39	2.34	2.25	2.25
18	2.36	2.36	2.49	2.56	2.52	2.19	2.32	2.31	2.26	2.21	2.12	2.12
19	2.21	2.21	2.34	2.42	2.37	2.06	2.20	2.19	2.14	2.08	1.98	1.98
20	2.10	2.10	2.23	2.31	2.26	1.96	2.09	2.08	2.04	1.98	1.89	1.89
21	1.97	1.97	2.10	2.17	2.13	1.83	1.96	1.95	1.91	1.86	1.77	1.77
22	0.00	0.00	2.83	2.89	2.85	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 3-31: Group A.2-BIP Slice of Day Table for Monthly Peak Day (Portfolio Adjusted 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	2.29	2.29	0.00	0.00	0.00	2.51	2.53	2.50	2.49	2.38	2.34	2.34
18	2.24	2.24	2.26	2.28	2.32	2.40	2.41	2.40	2.40	2.33	2.30	2.30
19	2.26	2.26	2.28	2.29	2.31	2.34	2.35	2.34	2.36	2.33	2.31	2.31
20	2.27	2.27	2.29	2.30	2.33	2.36	2.37	2.36	2.38	2.34	2.32	2.32
21	2.32	2.32	2.34	2.35	2.39	2.48	2.49	2.47	2.47	2.40	2.37	2.37
22	0.00	0.00	2.36	2.37	2.40	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 3-32: Group A.4 Slice of Day Table for Monthly Peak Day (Portfolio Adjusted 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	11.96	11.96	0.00	0.00	0.00	15.80	16.69	17.37	17.45	17.29	17.29	17.29
18	11.96	11.96	11.96	11.96	14.99	15.80	16.69	17.37	17.45	17.29	17.29	17.29
19	11.96	11.96	11.96	11.96	14.99	15.80	16.69	17.37	17.45	17.29	17.29	17.29
20	11.96	11.96	11.96	11.96	14.99	15.80	16.69	17.37	17.45	17.29	17.29	17.29
21	11.96	11.96	11.96	11.96	14.99	15.80	16.69	17.37	17.45	17.29	17.29	17.29
22	-2.55	-2.55	11.96	11.96	14.99	-3.39	-3.58	-3.73	-3.75	-3.72	-3.72	-3.72
23	-2.20	-2.20	-2.55	-2.55	-3.22	-2.94	-3.10	-3.23	-3.25	-3.22	-3.22	-3.22
24	0.00	0.00	-2.20	-2.20	-2.79	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 3-33: Group A.5 Slice of Day Table for Monthly Peak Day (Portfolio Adjusted Aggregate Impacts (MW))

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sep	Oct	Nov	Dec
1	[redacted]											
2												
3												
4												
5												
6												
7												
8												
9												
10												
11												
12												
13												
14												
15												
16												
17												
18												
19												
20												
21												
22												
23												
24												

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

Table 3-34: Group A.6 Slice of Day Table for Monthly Peak Day (Portfolio Adjusted 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	7.99	7.99	7.99	15.11	24.75	36.19	37.81	36.46	32.80	17.88	8.35	8.35
13	6.25	6.25	6.25	15.59	28.12	43.13	45.27	43.48	38.83	19.16	6.51	6.51
14	6.08	6.08	6.08	17.76	33.22	52.10	54.86	52.65	47.03	22.38	6.32	6.32
15	9.08	9.08	9.08	22.97	41.10	63.63	67.02	64.48	57.97	28.67	9.42	9.42
16	15.25	15.25	15.25	31.03	51.36	77.09	81.08	78.31	71.04	37.85	15.81	15.81
17	19.64	19.64	19.64	33.69	51.63	74.71	78.45	76.18	69.76	40.21	20.42	20.42
18	22.09	22.09	22.09	33.55	48.13	67.11	70.36	68.72	63.44	39.28	23.06	23.06
19	19.92	19.92	19.92	28.13	38.61	52.33	54.86	53.93	50.06	32.62	20.95	20.95
20	14.09	14.09	14.09	19.01	25.31	33.63	35.33	35.03	32.64	22.07	15.00	15.00
21	7.21	7.21	7.21	9.40	12.17	15.97	16.98	17.19	16.06	11.21	7.94	7.94
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 3-35: Group B.2 Slice of Day Table for Monthly Peak Day (Portfolio Adjusted 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	-0.71	-0.71	0.00	0.00	0.00	-0.89	-0.89	-0.85	-0.81	-0.72	-0.68	-0.68
18	0.00	0.00	-0.74	-0.77	-0.82	0.01	0.01	0.01	0.01	0.01	0.01	0.01
19	0.77	0.77	0.00	0.01	0.01	0.88	0.89	0.87	0.84	0.79	0.74	0.74
20	1.47	1.47	0.74	0.77	0.80	1.67	1.68	1.67	1.63	1.52	1.43	1.43
21	2.15	2.15	1.43	1.49	1.55	2.45	2.46	2.43	2.37	2.20	2.09	2.09
22	0.00	0.00	2.00	2.07	2.17	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 CONCLUSIONS AND RECOMMENDATIONS

The non-residential ELRP pilots did not deliver statistically significant demand reductions in PY 2023 while the A.4 residential battery storage pilot did deliver substantial significant savings. For both pilots there is room for improvement. The recommendations below may not be currently funded and may not be within PG&E's control, and costs and feasibility need to be considered alongside other research and program priorities.

4.1 ELRP RECOMMENDATIONS

- **Reserve ELRP dispatch for clear emergency conditions.** Significant load reductions were observed for PY 2022 and largely not for PY 2023 events. PY 2022 events were also dispatched under more extreme conditions and may be more a function of the emergency conditions under which the event is called. Reserving dispatch to clear emergency conditions which are clearly communicated to participants may be more in line with participant expectations and understanding of the program and may deliver greater impacts when it is called. This may include not calling event in years where extreme weather conditions are not experienced.

- **Improve advance notice.** PY 2022 events were also with day-ahead notice, compared to day-of and even hour-ahead notice in PY 2023. The advance notice received by participants, which is a function of when CAISO Emergency Energy Alerts are triggered may also indirectly be a function of extremity of emergency conditions at the time of the alert. To the extent possible, earlier advance notice, ideally day ahead, is likely to improve response to ELRP event notifications.

- **Collect data to inform participant response time assumptions.** Two PY 2022 was fundamentally different than PY 2022 due to the extremity of the system and weather conditions but also the day ahead notification given to participation to respond to events, versus the short day ahead, hour ahead notice given in PY 2023. A better understanding of resource availability and load response barriers under different notification scenarios will better inform load reduction forecasting. This may include process surveys or interviews with large non-residential ELRP participant sites.

APPENDIX

A. INDIVIDUAL SITE REGRESSIONS WITH SYNTHETIC CONTROLS

Individual site regressions with synthetic controls and site-specific specifications were used as a supplementary method for estimating load impacts for PY 2023 impacts for Non-Residential ELRP. The approach is implemented on hourly participant site loads. It relies on control sites that did not experience the intervention (up to five matched to each participant site), lagged participant site usage, an industry usage profile, solar irradiance, plus weather and time characteristics, to estimate the counterfactual. The model estimates a counterfactual load using weather and these various synthetic controls and predictors. A separate model is estimated for each hour of day and all modeling excludes event days. Reductions are the difference between the observed participant site and predicted counterfactual loads. With a regression model with synthetic controls, one should observe:

- Very similar energy use patterns for participant site and counterfactual loads when the intervention is not in place.
- A change in demand patterns for customers who are dispatched or subject to time varying prices, but no similar change for the counterfactual load.
- The timing of the change should coincide with the introduction of intervention.

The use of individually specified site-specific regression models allows for incorporation of a subset of possible parameters that best predict out of sample loads for each site and does not rely on finding a single ideal match. The functional form of the regression with synthetic controls differs from a panel difference in difference regression in that usage for the control or controls are specified as right hand predictor variables. This enables the incorporation of multiple controls and the magnitude of coefficients for each control essentially weights the effect of each control in the regression which directly estimates the counterfactual load. In a difference in difference regression, usage for the single matched control is structured on a separate record from the treatment site and a treatment effect is instead estimated. The counterfactual load is then derived by adding back the treatment effect to the observed load. The model equation including the full set up possible parameters is presented below in Equation A 0-1 and Table A 0-1. In practice the model used for each site and included a varying subset of these parameters. A separate model was estimated for each hour of the day.

Equation A 0-1: Ex Post Regression Model for Non-Residential ELRP

$$kW_t = \mathrm{a} + \sum_{n=1}^{max} \mathrm{b} \cdot kW\_0_{n,t} + \sum_{n=1}^{max} \mathrm{c}_n \cdot kW\_1_{t-n} + \sum_{n=1}^{max} \mathrm{d}_n \cdot month_n + \sum_{n=1}^{max} \mathrm{e}_n \cdot dow_n + \mathrm{f} \cdot solar_t + \mathrm{g} \cdot industry_t + \sum_{n=1}^{max} \mathrm{h}_{n,t} \cdot spline_{n,t} + \delta_t + \varepsilon_{i,t}$$

Where:

Table A 0-1: Ex Post Regression Elements for Non-Residential ELRP

kW_t	Is the site usage for each time period.
kW_0_t	Is the synthetic control usage for up to 5 matched controls for each time period. The specific number of controls used varied by site. These synthetic controls were selected based on Euclidean distance matching (the winning matching method in a tournament of 8 methods). They did not experience the treatment.
kW_1_{t-n}	Is the lagged participant site usage and could by one of: no lags, 1 day, 1 week, 2 weeks, 1 day and 1 week, and 1 and 2 weeks. The specific lags used varied by site.
a	Is the model intercept.
b	Coefficients for the synthetic control loads. The specific number of controls used varied by site and ranged from 0 to 5.
c	Coefficients for the participant site usage lags. The specific lags used varied by site.
d	Coefficients for each month.
e	Coefficients for each day of week.
f	Coefficient for solar irradiance across for each time period. Inclusion of this parameter varied by site.
g	Coefficient for industry load profile: normalized hourly loads (scaled from 0 to 1) for control sites in the same industry as the participant site. Industry grouping developed using NAICS code and customer names indicative of industry activity. Inclusion of this parameter varied by site.
h	Coefficients for weather sensitivity of loads, based on a 2 knot spline of 24 hour moving average of temperature, averaged across participant sites for each time period.
δ_t	Represents time effects for each time period. This accounts for observed and unobserved factors that vary by time but affect all customers equally.
$\varepsilon_{i,t}$	Represents the error term for each individual customer and time period.