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Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

DRAFT REPORT

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2024 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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Demand Side Analytics Team

- Alana Lemarchand
- Savannah Horner

PG&E Team

- Jahon Amirebrahimi
- Randy Chiu
- Stephanie Wong

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 2024 demand reductions due to dispatch operations? What is the magnitude of future dispatchable load reduction capability for 1-in-2 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 $1/kWh payment for A.6 and a $2/kWh payment for the other subgroups, determined using baseline settlement rules. Nine non-residential ELRP events were called in PY 2024, with different subgroups being dispatched for specific events. The average PY 2024 weekday 6pm to 9pm event did not produce meaningful load reductions when evaluated across all non-residential ELRP subgroups (A.1, A.1 BIP, A.2, A.2 BIP, A.5, and B.2). Seven A.4 residential ELRP events were called in PY 2024, and the average 6pm to 9pm event produced 19.7 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, including BIP and non-BIP enrollees.
- A.2. Non-residential aggregators, including PG&E's Base Interruptible Program aggregators.
- A.3. Rule 21 exporting distributed energy resources.
- A.4. Virtual Power Plant (VPP) aggregators.
- A.5. Electric vehicle and vehicle-grid-integration aggregators.
- A.6. Residential customers.

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 operate through 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 decreased in 2024 to $1/kWh. The eligibility, targeting, and rollout of each subgroup are entirely different.

This study analyzes two primary research questions:

- What were the 2024 demand reductions due to dispatch operations?
- What is the magnitude of future dispatchable load reduction capability for 1-in-2 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. A.4 and B.2 produced statistically significant incremental impacts across all the events dispatched, [redacted]. Subgroup A.6 was not dispatched in PY 2024. There were no enrollments in subgroup A.3 in PY 2024, and B.1 is not in the scope of this study.

Table 1-1: Summary of 2024 Average Weekday Event Ex Post Demand Reductions[1]

Group	Sites	Load without DR (MW)	Load reduction (MW)	% Reduction	Significant (90% CI)	Significant (95% CI)
A.1: Non-Res Customers	10,932	682.18	9.31	1.4%	No	No
A.1-BIP: Non-Res Customers	14	[redacted]				
A.2: Non-Res Customers	11					
A.2-BIP: Non-Res Aggregators	22	8.10	-0.78	-9.7%	No	No
A.4: Virtual Power Plants (VPPs)	6,714	2.91	13.50	464.5%	Yes	Yes
A.5: Vehicle-Grid-Integration (VGI) Aggregators	4	[redacted]				
A.6: Residential Customers	1,417,178	N/A	N/A	N/A	N/A	N/A
B.2: IOU Capacity Bidding Programs (CBPs)	326	31.15	2.13	6.8%	Yes	Yes
Total Customers Dispatched	**18,023**	**749.26**	**19.77**	**2.6%**	**Yes**	**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, A.2-BIP, and B.2 enrollments are expected to remain flat and end after 2027. Subgroups A.1, A.4, and A.5 are expected to grow until 2027. Subgroup A.6 enrollment is forecasted to decline until 2025 when it will discontinued.

[1] The average weekday event results incorporate impacts across multiple event windows (e.g. 6 pm to 9 pm and 5 pm to 8 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	A.2-BIP	A.4	A.5	A.6	B.2	Total
2024	10,870	11	11	18	6,682	4	1,413,585	317	**1,431,498**
2025	11,253	6	25	5	7,285	365	1,360,925	108	**1,379,972**
2026	11,431	6	25	5	7,393	465	0	108	**19,433**
2027	11,595	6	25	5	7,502	566	0	108	**19,807**

Table 1-3 summarizes portfolio adjusted ELRP dispatchable ex ante reductions under August worst day conditions for a PG&E 1-in-2 weather year. Table 1-4 shows the same for program specific impacts. For most groups, ELRP load reductions are assumed to be a function of curtailment of the weather sensitive load on a percent basis. The results reflect the reduction capability from 4pm to 9pm, which aligns with resource adequacy requirements. Exporting groups (A.4, A.5) apply a consistent per-customer reduction across all weather specifications, over the three hours in the 5pm to 8pm window to align with the program rules which limit events to three hours. The ex ante load reduction predictions are primarily developed using PY 2024 impacts.

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

Year	A.1	A.1-BIP	A.2	A.2-BIP	A.4	A.5	A.6	B.2	Total
2024	13.1	[redacted]	[redacted]	0.0	20.4	[redacted]	44.8	1.2	**72.4**
2025	13.8	[redacted]	[redacted]	[redacted]	22.2	[redacted]	43.5	0.4	**72.0**
2026	14.0	[redacted]	[redacted]	[redacted]	22.5	[redacted]	[redacted]	0.4	**29.0**
2027	14.3	[redacted]	[redacted]	[redacted]	22.9	[redacted]	[redacted]	0.4	**29.4**

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

Year	A.1	A.1-BIP	A.2	A.2-BIP	A.4	A.5	A.6	B.2	Total
2024	13.1	[redacted]	[redacted]	0.0	20.4	[redacted]	44.8	1.3	**72.4**
2025	13.8	[redacted]	[redacted]	[redacted]	22.2	[redacted]	43.5	0.4	**72.0**
2026	14.0	[redacted]	[redacted]	[redacted]	22.5	[redacted]	[redacted]	0.4	**29.0**
2027	14.3	[redacted]	[redacted]	[redacted]	22.9	[redacted]	[redacted]	0.4	**29.4**

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, including BIP and non-BIP enrollees.
- A.2. Non-residential aggregators, including PG&E's Base Interruptible Program aggregators.
- A.3. Rule 21 exporting distributed energy resources.
- A.4. Virtual Power Plant (VPP) aggregators.
- A.5. Electric vehicle and vehicle-grid-integration aggregators.
- A.6. Residential customers.

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 operate through 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 decreased in 2024 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/

	Eligibility Requirements
	▪ 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.
A.3	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
A.4	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.
A.5	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

	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 2024 – 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 2024?
4	What are the ex ante load reduction capabilities for 1-in-2 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. When ELRP events are dispatched, was the 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).

[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

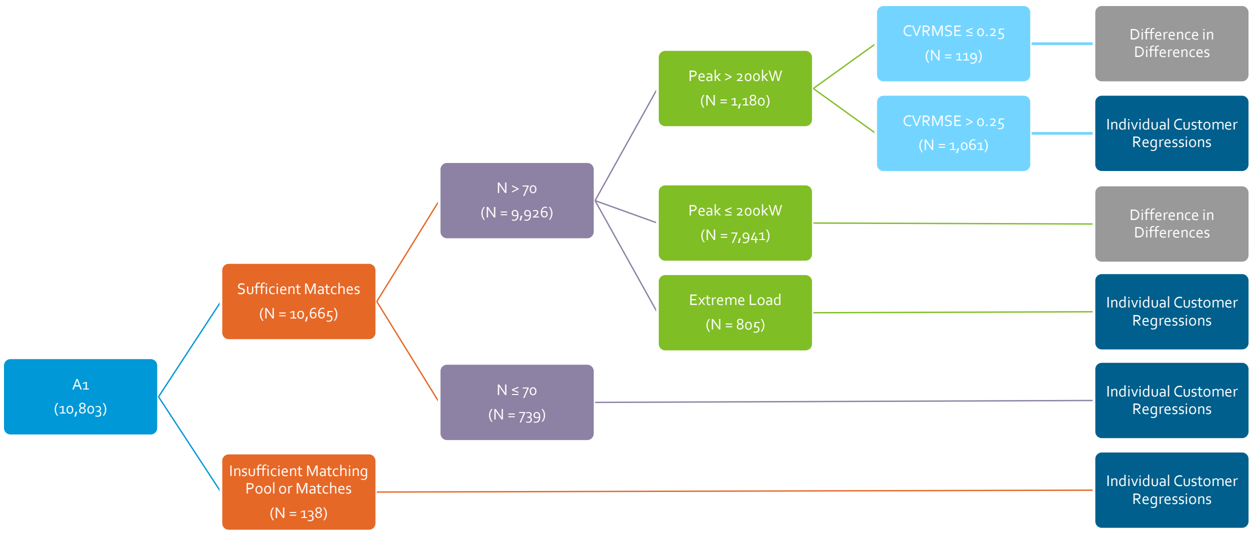


Table 2-3 summarizes the approach or approaches used for each subgroup. Note that for some subgroups a combination of methods was used. Additionally, no ex-post evaluation methodologies were applicable to subgroup A.6 since this subgroup was not dispatched in PY 2024. However, if events had been called, 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	✓	
A.2-BIP	✓	
A.4		✓
A.5	✓	
A.6	N/A	N/A
B.2	✓	

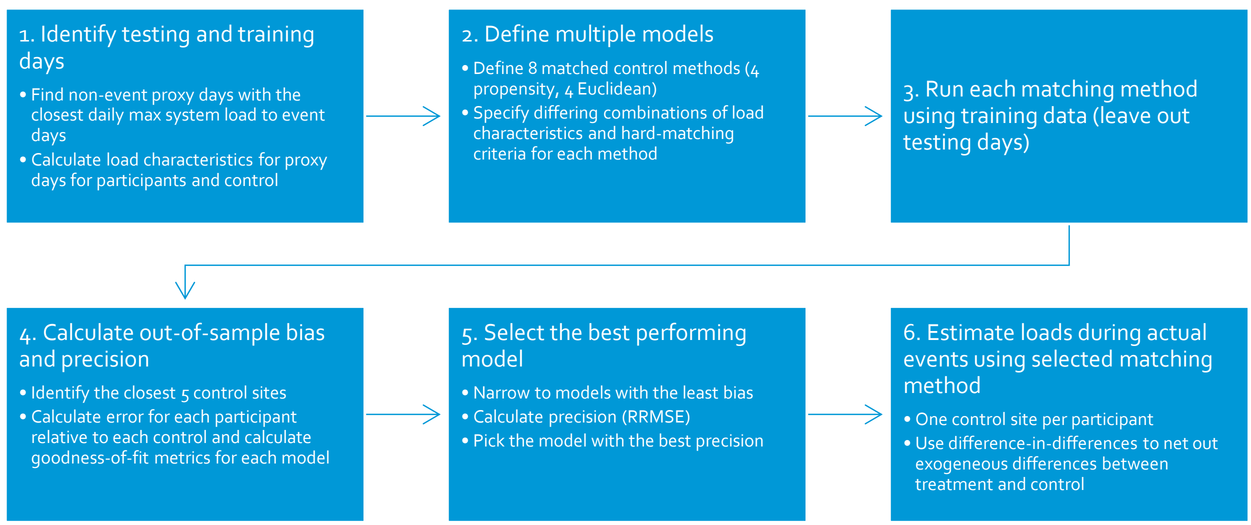
Site-specific models for individual customer regressions were selected among dozens of potential specifications, which included synthetic controls[4] using one or more matched control site to help control for factors outside of the ELRP events. Similarly, the difference-in-differences approach used a matched control group to net out changes in energy usage patterns not due to the ELRP events. As

[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

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, as described in the appendix), 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



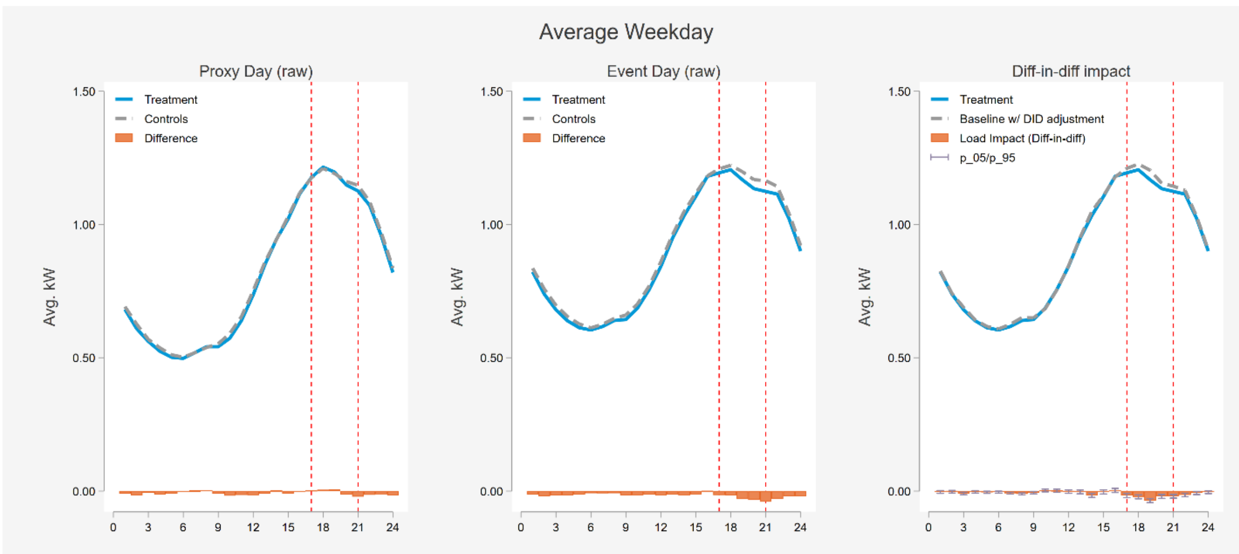
As described above, difference-in-differences with matched controls was the primary evaluation methodology used, except in cases where there were few sites or large sites with noisy load patterns[6]. Figure 2-3 below demonstrates the mechanics of a difference-in-difference calculation. In the first panel, average observed loads on proxy days are shown for participants and for their matched controls.

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

[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.

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[7]



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 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[8]). Site specific load impacts were estimated with using the winning model for each site.

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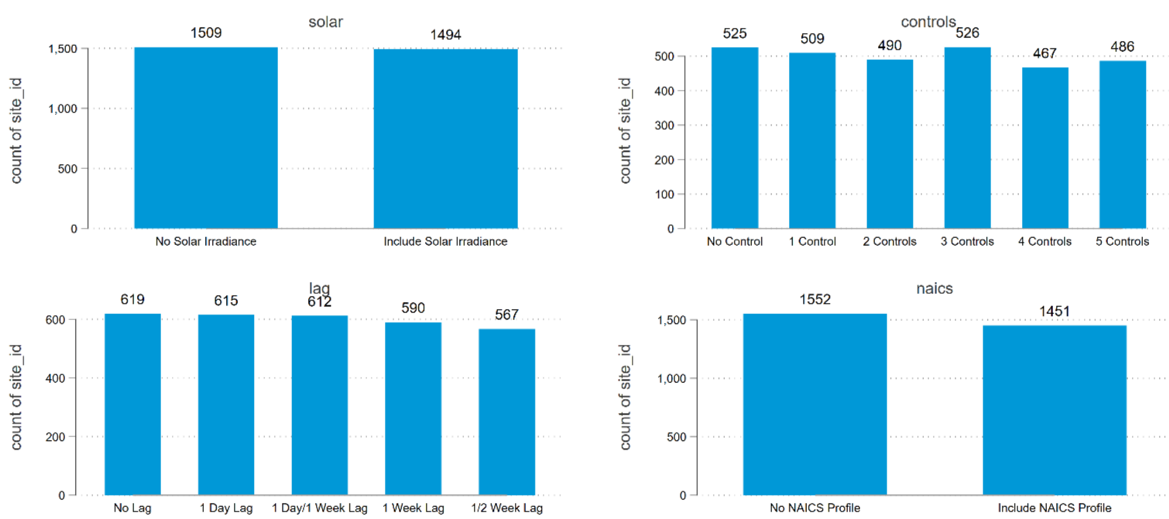
[7] This graph is not specific to ELRP but serves as an example of a difference-in-difference calculation.
[8] MAE was used rather that Mean Average Percent Error (MAPE) to ensure robustness for sites with loads very close to zero, common for sites with solar or other generation.

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[9]
- Inclusion of local solar irradiance data[10]
- Number of control sites[11]
- Lags of load data[12]

Figure 2-4 shows the different model parameters that were included in the site-specific model tournament and the number of sites[13] for which each parameter was included in the winning model. This is shown for all groups and all sites that were analyzed using an individual customer regression. The wide spread across parameters indicates that it was important to allow for individually tailored models to be selected for each participating site.

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



[9] 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.
[10] Specific to the weather station nearest to the participant.
[11] Ranges from 0 to 5, selected using the out of sample match selection process.
[12] 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.
[13] Shown for the 3,003 sites across groups for which individual customer regressions were selected.

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.1 BIP, A.2, A.2 BIP, A.4, A.5, B.2
Data sources / samples	▪ All event season data for the past program year for ✓ all 11,309 Non-Residential ELRP participant sites and all 6,714 A4 participant sites ✓ a control pool of 60k commercial non-participants and 4k non-participant residential sites with battery storage
Segmentation	▪ ELRP Subgroup ▪ Dual enrollment ▪ Industry ▪ Solar Status ▪ LCA ▪ SubLAP ▪ Climate zone
Estimation method (Ex-post)	▪ Primary method: difference-in-differences with matched controls ▪ Secondary method: site specific regression models with synthetic controls o 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 2024 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.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 and A.5 subgroup participants receive dispatch signals sent to the battery storage devices or electric vehicles/charging stations installed on the premises, respectively.

3.1 EVENT CHARACTERISTICS

Event impacts were assessed by site (service account ID-service point ID 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 2024 event season (the first event was called on July 10 and the last on October 30). For A.6 a subset of the large participant population was sampled. 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 2024 due to lack of events. 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.

Table 3-1: Participant Populations

ELRP Group	Sector(s)	Total sites	Sites in analysis*
A.1	Non-Residential	10,932	10,702
A.1BIP	Non-Residential	14	10
A.2	Non-Residential	11	11
A.2BIP	Non-Residential	22	21
A.4	Non-Residential & Residential	6,714	6,353
A.5	Non-Residential	4	4
A.6	Residential	1,417,178	49,732
B.2	Non-Residential	326	313
Total		**1,435,201**	**67,146**

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

Table 3-2 shows the ten PY 2024 ELRP event days and the PG&E system peak load on each day. The most common event window covered 5pm to 8pm and 6pm to 9pm, where both cover a duration of three hours. The July 24th event was called from 6pm to 9pm for all subgroups, except A.2 and A.6. All ten events occurred on weekdays, and none occurred on weekends or holidays. No events were called for subgroup A.6 in PY 2024.

Table 3-2: ELRP Events in 2024

Event date	Day of week	Max PG&E system load (MW)	Event window	A.1	A.1-BIP	A.2	A.2-BIP	A.4	A.5	A.6	B.2
7/10/2024	Wednesday	19,652	6 to 9 pm					✓			
7/11/2024	Thursday	21,159	6 to 9 pm					✓	✓		
7/24/2024	Wednesday	19,829	6 to 9 pm	✓	✓		✓	✓	✓		✓
9/4/2024	Wednesday	18,291	5 to 8 pm					✓	✓		
9/5/2024	Thursday	18,349	4 to 9 pm			✓	✓				
9/5/2024	Thursday	18,349	5 to 8 pm					✓	✓		
9/6/2024	Friday	18,072	5 to 8 pm			✓	✓	✓	✓		
9/9/2024	Monday	16,961	5 to 8 pm						✓		
9/9/2024	Monday	16,961	6 to 8 pm					✓			
10/17/2024	Thursday	12,649	5 to 8 pm						✓		
10/24/2024	Thursday	12,209	6 to 9 pm						✓		
10/30/2024	Wednesday	12,268	6 to 9 pm						✓		

* Highlighted rows indicate event days where another program was also dispatched.

Dual enrollment is allowed for some of the ELRP subgroups, which is categorized in Table 3-3. Three of the ELRP subgroups require dual enrollment; A.1 BIP and A.2 BIP must be enrolled in the Base Interruptible Program (BIP) and B.2 must be enrolled in the Capacity Bidding Program (CBP). Customers in the A.1 and A.6 subgroups can also be enrolled in Peak Day Pricing (PDP). In addition to the dually enrolled populations, Table 3-3 lists the ELRP event days where a dual program was also called.

Table 3-3: Dual Enrollment Populations

ELRP Group	Dual Enrollment Allowed	Sites Dually Enrolled	Days with Dual Event Overlap
A.1	PDP	970	-
A.1BIP	BIP	14	-
A.2BIP	BIP	22	-
A.6	PDP	24,274	-
B.2	CBP	326	-

Notably, these participants were not dually dispatched during any of the ELRP events this season. This is specifically important for A1.BIP and A2.BIP because ELRP settlements only occur for periods with a coincident BIP event. For these groups, this would indicate that a response would not be expected on event days.

3.2 DATA SOURCES AND ANALYSIS METHOD

Table 3-4 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 3-4: Non-Residential and Residential ELRP Event Impact Evaluation Data Sources

Source	Comments
Hourly interval data	▪ Summer 2024 ▪ 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: 11,309 customer sites ▪ Residential treatment: 6,714 A.4 sites ▪ Non-residential controls: 60k non-residential sites ▪ A4 controls: 4k residential sites with battery storage ▪ Dual enrollment, subLAP used in matched control selection ▪ NAICS codes for development of industry profiles
PG&E hourly system loads	▪ Summer 2024 ▪ 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.

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, and it is currently the largest non-residential ELRP subgroup with over 10,000 participating sites. There was one event called for subgroup A.1 in PY2024 on July 24, 2024 from 5pm to 9pm. Table 3-5 summarizes the load reductions and participant weighted event temperatures for ELRP A.1 sites each event and for the average weekday event.

A.1 showed no statistically significant event impacts. One possible reason for this finding is that there was limited advance event notice for the July 24th event, which did not give participants sufficient time to shed load.

Table 3-5: ELRP A.1 Event Reductions

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post) Aggregate (MW)	Reductions (Ex Post) % Reduction	Reductions (Ex Post) Average Site (kW)	Significant (90% CI)	Significant (95% CI)
7/24/2024	6 to 9 pm	95.7	10,932	9.3	1.4%	0.9	No	No
Avg Weekday 6-9pm	**6 to 9 pm**	**95.7**	**10,932**	**9.3**	**1.4%**	**0.9**	**No**	**No**
Avg Weekday (any)	**6 to 9 pm**	**95.7**	**10,932**	**9.3**	**1.4%**	**0.9**	**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 20 participants. Like the A.1 subgroup, A.1-BIP only called one event in PY 2024. Table 3-6 summarizes the load reductions and participant weighted event temperatures for ELRP A.1-BIP sites during each event and for the average weekday event.

[redacted]

Table 3-6: ELRP A.1-BIP Event Reductions

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post) Aggregate (MW)	Reductions (Ex Post) % Reduction	Reductions (Ex Post) Average Site (kW)	Significant (90% CI)	Significant (95% CI)
7/24/2024	6 to 9 pm	79.6	14	[redacted]				
Avg Weekday 6-9pm	**6 to 9 pm**	**79.6**	**14**	[redacted]				
Avg Weekday (any)	**6 to 9 pm**	**79.6**	**14**	[redacted]				

3.3.3 ELRP Group A.2 Impacts by Event

Group A.2 is designated for non-residential aggregators and had enrollments beginning in PY24. There were two events called for subgroup A.2 on two consecutive days. Table 3-8 summarizes the load reductions and participant weighted event temperatures for ELRP A.2 sites during each event and for the average weekday event.

[redacted]

Table 3-7: ELRP A.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)
9/5/2024	4 to 9 pm	94.5	11	[redacted]				
9/6/2024	5 to 8 pm	96.2	11	[redacted]				
Avg Weekday 5-8pm	**5 to 8 pm**	**96.2**	**11**	[redacted]				
Avg Weekday (any)	**4 to 9 pm**	**94.7**	**11**	[redacted]				

3.3.4 ELRP Group A.2-BIP Impacts by Event

Group A. 2-BIP is designated for non-residential, BIP aggregators. There were three events called for subgroup A.2-BIP in PY 2024, across a variety of durations and start times. Table 3-8 summarizes the load reductions and participant weighted event temperatures for ELRP A.2-BIP sites during each event and for the average weekday event.

[redacted]

Table 3-8: ELRP 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)
7/24/2024	6 to 9 pm	95.6	22	-1.3	-16.1%	-57.8	No	No
9/5/2024	4 to 9 pm	94.9	22	-0.7	-9.2%	-33.4	No	No
9/6/2024	5 to 8 pm	96.2	22	-1.3	-17.7%	-59.2	No	No
Avg Weekday 5-8pm	**5 to 8 pm**	**96.2**	**22**	**-1.3**	**-17.7%**	**-59.2**	**No**	**No**
Avg Weekday 6-9pm	**6 to 9 pm**	**95.6**	**22**	**-1.3**	**-16.1%**	**-57.8**	**No**	**No**
Avg Weekday (any)	**4 to 9 pm**	**95.7**	**22**	**-0.8**	**-9.7%**	**-35.6**	**No**	**No**

3.3.5 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 2024, there were over 6,000 residential participant sites. There were seven events called for subgroup A.4 in PY 2024, across a variety of durations and start times. Both the individual event days and the average weekday event reductions in Table 3-9 were significant and meaningful. In the tables, the bars show a visual comparison of the reductions that are numerically labeled on the left of the bars. Reductions were lower on July 24th due to a technical issue causing notifications to be sent after the beginning of the event.

Aggregate reductions for significant events range from 15.8 MW (July 24th) to 30.7 MW (September 9th). 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.

Additionally, A.4 participants experience a statistically significant increase in load immediately before and after the event. This is seen prior to the event as typical battery dispatch, used to offset the whole-home load, is halted to preserve the state-of-charge for actual event hours. Similarly, the post-event charging is the result of participant's having depleted their battery over the course of the event, requiring them to draw more from the grid than they would have if their battery still had its typical charge.

Table 3-9: ELRP A.4 Event Reductions

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post) Aggregate (MW)	Reductions (Ex Post) Average Site (kW)	Significant (90% CI)	Significant (95% CI)
7/10/2024	6 to 9 pm	82.7	6,679	21.0	3.2	Yes	Yes
7/11/2024	6 to 9 pm	86.9	6,681	22.3	3.3	Yes	Yes
7/24/2024	6 to 9 pm	81.9	6,682	15.8	2.4	Yes	Yes
9/4/2024	5 to 8 pm	81.2	6,739	21.5	3.2	Yes	Yes
9/5/2024	5 to 8 pm	85.0	6,739	20.7	3.1	Yes	Yes
9/6/2024	5 to 8 pm	83.3	6,740	21.3	3.2	Yes	Yes
9/9/2024	6 to 8 pm	72.7	6,739	30.7	4.5	Yes	Yes
Avg Weekday 5-8pm	**5 to 8 pm**	**83.2**	**6,739**	**21.2**	**3.1**	**Yes**	**Yes**
Avg Weekday 6-9pm	**6 to 9 pm**	**83.8**	**6,681**	**19.7**	**3.0**	**Yes**	**Yes**
Avg Weekday (any)	**5 to 9 pm**	**81.6**	**6,714**	**13.5**	**2.0**	**Yes**	**Yes**

3.3.6 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 2024. There were nine events called for subgroup A.5 in PY 2024, across a variety of durations and start times. Table 3-10 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 3-10: ELRP A.5 Event Reductions

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post)		Significant (90% CI)	Significant (95% CI)
				Aggregate (MW)	Average Site (kW)		
7/11/2024	6 to 9 pm	57.3	3	[redacted]			
7/24/2024	6 to 9 pm	58.7	3	[redacted]			
9/4/2024	5 to 8 pm	67.8	4	[redacted]			
9/5/2024	5 to 8 pm	63.6	4	[redacted]			
9/6/2024	5 to 8 pm	63.1	4	[redacted]			
9/9/2024	5 to 8 pm	60.8	4	[redacted]			
10/17/2024	5 to 8 pm	58.8	4	[redacted]			
10/24/2024	6 to 9 pm	52.8	4	[redacted]			
10/30/2024	6 to 9 pm	50.4	4	[redacted]			
Avg Weekday 5-8pm	**5 to 8 pm**	**62.8**	**4**	[redacted]			
Avg Weekday 6-9pm	**6 to 9 pm**	**54.3**	**4**	[redacted]			
Avg Weekday (any)	**5 to 9 pm**	**59.1**	**4**	[redacted]			

3.3.7 ELRP Group A.6 Impacts by Event

There were no events called for Group A.6 during PY 2024, so ex post impacts cannot be evaluated for this group.

3.3.8 ELRP Group B.2 Impacts by Event

Group B.2 is designated for IOU Capacity Bidding Program (CBP) PDR resources and was comprised of 326 participating sites in PY 2024. There was only one event called for subgroup B.2 in PY 2024 on July 24th, 2024 from 5pm to 9pm. Table 3-11 summarizes the load reductions and participant weighted event temperatures for ELRP B.2 sites during each event and for the average weekday event.

The average event reduction was statistically significant, which was primarily driven by the reduction of the an aggregator that had a large number of agricultural customers.

Table 3-11: ELRP B.2 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)		
7/24/2024	6 to 9 pm	100.4	326	2.1	6.8%	6.5	Yes	Yes
Avg Weekday 6-9pm	**6 to 9 pm**	**100.4**	**326**	**2.1**	**6.8%**	**6.5**	**Yes**	**Yes**
Avg Weekday (any)	**6 to 9 pm**	**100.4**	**326**	**2.1**	**6.8%**	**6.5**	**Yes**	**Yes**

3.4 EX ANTE LOAD IMPACTS

A key objective of this 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) 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:

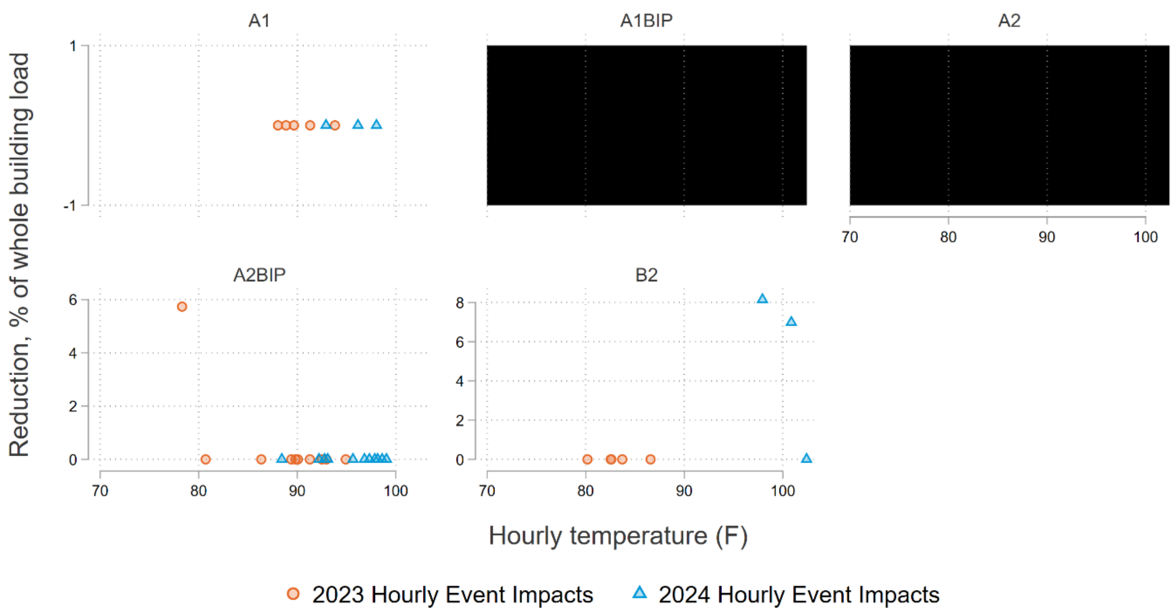
1. What are the most event relevant weather conditions for an emergency program such as ELRP?
2. How do observed impacts vary under those weather conditions?

The first question is important for determining which historical impacts should be used for developing the ex ante forecast. PY 2024 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. The previous year's evaluation relied on these PY 2022 impacts because it was believed that the PY 2023 dispatches, specifically the notifications, were abnormal. This year's events were more similar to PY 2023 than PY 2022. Ideally, ex ante relies on multiple years of data, but the customer mix year-over-year for the majority of ELRP subgroups changes drastically. For this reason, all subgroups, except A.1, rely on PY 2024 impacts. The A.1 impact modelling relies on a combination of PY 2022, PY 2023, and PY 2024.

The second question which should be asked when developing an ex ante weather model is how observed impacts vary under those weather conditions. Figure 3-1 shows the hourly percent reductions for historical weekday events as a function of hourly temperatures for sites in each ELRP subgroup[14]. Notably, there is no clear relationship between impacts and temperature despite the relatively wide range of temperatures. Given this lack of a clear relationship, ex ante estimates reflect static average percent reductions for each event hour. Therefore, ex ante reductions are assumed to vary only as a function of the reference load.

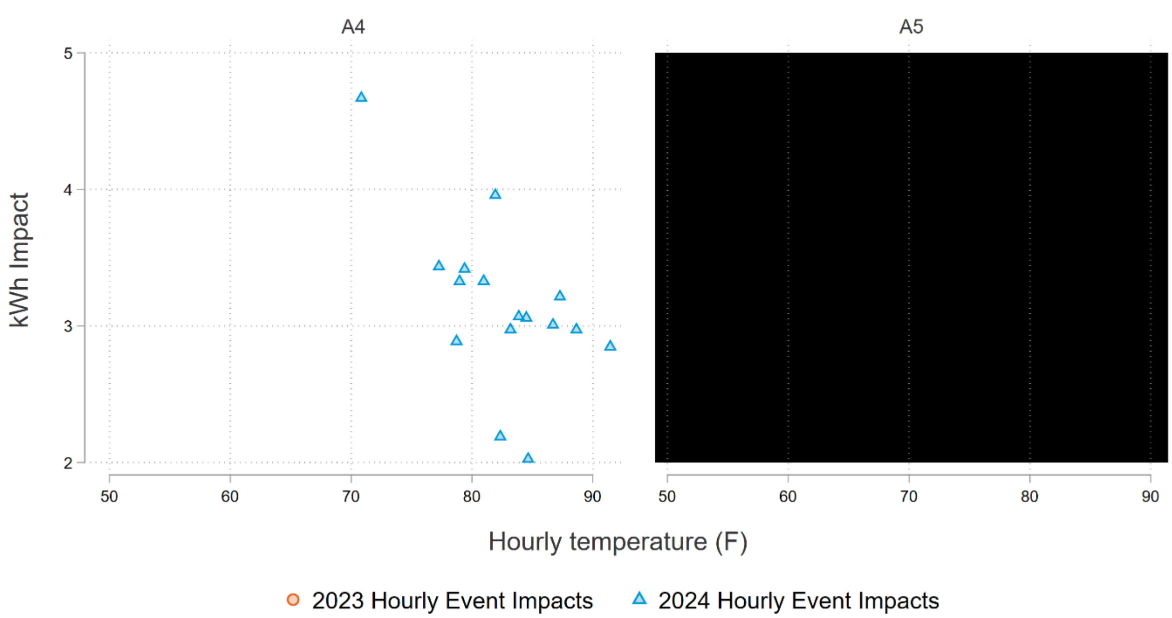
[14] Impacts that are not statistically significant have been recoded to zero.

Figure 3-1: ELRP Hourly Percent Reductions and Temperatures



For the A.4 and A.5 subgroups, which is comprised of technology responding to dispatch signals, impacts can be assumed to be a function of the battery capacity made available by participants. Figure 3-2 shows the average kWh per-customer reduction for the A.4 and A.5 events. Assessment of these PY 2024 events show no clear correlation between kWh reductions and weather.

Figure 3-2: ELRP A4, A5 Hourly 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.

Program specific ex ante estimates, which are the unadjusted impacts of the program, are calculated by using ELRP-only and dually enrolled customers on all ELRP event days. Summing up program specific aggregate ex-ante estimates across all evaluation reports could generate double counting of impacts. Portfolio adjusted ex ante estimates are the population's incremental savings generated by ELRP dispatch. These impacts avoid double counting across evaluation reports, which allows for summing up aggregate ex-ante estimates across all evaluation reports to get an estimate of PG&E's portfolio of DR programs. Table 3-12 defines the dual enrolled programs for consideration in each subgroup.

Table 3-12: Eligible Dually Enrolled Programs for Ex Ante Considerations

Dual Group	Study	Ex-Ante Program Specific	Ex-Ante Portfolio Adjusted
ELRP A1, A6 + PDP	ELRP	ELRP and overlapping events, single and dual customers	PDP event average removed from impacts
	PDP	PDP and overlapping events, single and dual customers	Ex ante impacts estimated based on ex post data from non-ELRP event days
ELRP B2 + CBP	ELRP	ELRP and overlapping events, single and dual customers	Any impacts beyond nomination
	CBP	CBP and overlapping events, single and dual customers	Impacts are capped at nomination

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 3-13 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 3-13: Participant Enrollment Forecast

Year	A.1	A.1-BIP	A.2	A.2-BIP	A.4	A.5	A.6	B.2	Total
2024	10,870	11	11	18	6,682	4	1,413,585	317	**1,431,498**
2025	11,253	6	25	5	7,285	365	1,360,925	108	**1,379,972**
2026	11,431	6	25	5	7,393	465	0	108	**19,433**
2027	11,595	6	25	5	7,502	566	0	108	**19,807**

PG&E developed the ELRP enrollment forecast that was used to scale the ex ante impacts. The enrollment forecast reflects current enrollment in PY 2024. For subgroups A.1-BIP, A.2, A.2-BIP, and B.2 enrollments are expected to remain flat and end after 2027. Subgroups A.1, A.4, and A.5 are expected to grow until 2027. Subgroup A.6 enrollment is forecasted to decline until 2025 when it will be discontinued.

3.4.4 ELRP Group A.1 Ex Ante Load Impacts

Group A.1 is designated for non-residential customers and is currently the largest ELRP subgroup by far with over 10,000 participating sites. Table 3-14 summarizes the program and portfolio adjusted ex ante demand reduction capability by forecast year for different planning conditions. The tables reflect dispatchable demand reductions available from 4 pm to 9 pm under August worst day conditions for 1-in-2 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 across PY 2022, PY 2023, and PY2024, weighted by the amount of customers currently enrolled that participated each year. Enrollments are assumed to grow through the last year of ELRP approval in 2027.

Table 3-14: ELRP A.1 Ex Ante Impacts for 1-in-2 August Worst Day (MW)

Year	Sites	CAISO		PG&E	
		Program	Portfolio	Program	Portfolio
2024	10,870	12.49	12.49	13.10	13.10
2025	11,253	13.18	13.18	13.81	13.81
2026	11,431	13.40	13.40	14.04	14.04
2027	11,595	13.60	13.60	14.25	14.25

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

Group A.1-BIP is designated for non-residential, BIP customers. Table 3-15 summarizes the program and portfolio adjusted ex ante demand reduction capability by forecast year for different planning conditions. [redacted] The tables reflect dispatchable demand reductions available from 4 pm to 9 pm under August worst day conditions for 1-in-2 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 2024 conditions. Enrollments are assumed to stay flat through the last year of ELRP approval in 2027.

Table 3-15: ELRP A.1-BIP Ex Ante Impacts for 1-in-2 August Worst Day (MW)

Year	Sites	CAISO		PG&E	
		Program	Portfolio	Program	Portfolio
2024	11	[redacted]			
2025	6				
2026	6				
2027	6				

3.4.6 ELRP Group A.2 Ex Ante Load Impacts

Group A.2 is designated for non-residential aggregators and only saw enrollments starting this year. Table 3-16 summarizes the program and portfolio adjusted ex ante demand reduction capability by forecast year for different planning conditions. The tables reflect dispatchable demand reductions available from 4 pm to 9 pm under August worst day conditions for 1-in-2 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 2024 conditions. Enrollments are assumed to stay flat through the last year of ELRP approval in 2027.

Table 3-16: ELRP A.2 Ex Ante Impacts for 1-in-2 August Worst Day (MW)

Year	Sites	CAISO		PG&E	
		Program	Portfolio	Program	Portfolio
2024	11	[redacted]			
2025	25	0.00	0.00	0.00	0.00
2026	25	0.00	0.00	0.00	0.00
2027	25	0.00	0.00	0.00	0.00

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

Group A.2-BIP is designated for non-residential, BIP aggregators. Table 3-17 summarizes the program and portfolio adjusted ex ante demand reduction capability by forecast year for different planning conditions. [redacted] The tables reflect dispatchable demand reductions available from 4 pm to 9 pm under August worst day conditions for 1-in-2 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 2024 conditions. Enrollments are assumed to stay flat through the last year of ELRP approval in 2027.

Table 3-17: ELRP A.2-BIP Ex Ante Impacts for 1-in-2 August Worst Day (MW)

Year	Sites	CAISO		PG&E	
		Program	Portfolio	Program	Portfolio
2024	18	0.00	0.00	0.00	0.00
2025	5	[redacted]			
2026	5				
2027	5				

3.4.8 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 program and portfolio adjusted ex ante demand reduction capability by forecast year for different planning conditions. The tables reflect dispatchable demand reductions available from 5 pm to 8 pm under August worst day conditions for 1-in-2 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 2024 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

[15] D.22-06-050 (488540633.PDF (ca.gov))

resources are required to provide three hours of reductions, so it is assumed that the kWh reductions will be spread evenly across the three hours of the 5pm to 8pm availability window.

Outside of the availability window, there is one hour of pre-event and two hours of post-event load impacts modelled. These are not factored into the impacts reported below but are included in the table generators to accurately reflect battery operation immediately preceding and following an event dispatch.

Table 3-18: ELRP A.4 Ex Ante Impacts for 1-in-2 August Worst Day (MW)

Year	Sites	CAISO		PG&E	
		Program	Portfolio	Program	Portfolio
2024	6,682	20.36	20.36	20.36	20.36
2025	7,285	22.20	22.20	22.20	22.20
2026	7,393	22.53	22.53	22.53	22.53
2027	7,502	22.86	22.86	22.86	22.86

3.4.9 ELRP Group A.5 Ex Ante Load Impacts

Group A.5 is designated for vehicle-grid integration (VGI) aggregators of non-residential electric vehicles or charging stations and was comprised of four participating sites in PY 2024. Table 3-19 summarizes the program and portfolio adjusted ex ante demand reduction capability by forecast year for different planning conditions. The tables reflect dispatchable demand reductions available from 5 pm to 8 pm under August worst day conditions for 1-in-2 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 2024 events is then divided by 3, to take into account the resource availability rules set to go into effect for PY2024.[16] Essentially, A.5 resources are required to provide three hours of reductions, so it is assumed that the kWh reductions will be spread evenly across the three hours of the 5pm to 8pm availability window.

Outside of the availability window, there are two hours of post-event load impacts modelled. These are not factored into the impacts reported below but are included in the table generators to accurately reflect charging operations immediately following an event dispatch.

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[16] D.22-06-050 (488540633.PDF (ca.gov))

Table 3-19: ELRP A.5 Ex Ante Impacts for 1-in-2 August Worst Day (MW)

Year	Sites	CAISO		PG&E	
		Program	Portfolio	Program	Portfolio
2024	4	[redacted]			
2025	365	1.71	1.71	1.71	1.71
2026	465	1.71	1.71	1.71	1.71
2027	566	1.71	1.71	1.71	1.71

3.4.10 ELRP Group A.6 Ex Ante Load Impacts

Group A.6 is designated for residential customers and was comprised of 1.4 million participating sites in PY 2024. Table 3-20 summarizes the program and portfolio adjusted ex ante demand reduction capability by forecast year for different planning conditions. The tables reflect dispatchable demand reductions available from 4 pm to 9 pm under August worst conditions for 1-in-2 weather conditions, which align with the planning conditions used for resource adequacy attribution. Since there were no A.6 events in PY 2024, 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 3-20: ELRP A.6 Ex Ante Impacts for 1-in-2 August Worst Day (MW)

Year	Sites	CAISO		PG&E	
		Program	Portfolio	Program	Portfolio
2024	1,413,585	37.59	37.59	44.82	44.82
2025	1,360,925	36.43	36.43	43.48	43.48
2026	0	[redacted]			
2027	0				

3.4.11 ELRP Group B.2 Ex Ante Load Impacts

Group B.2 is designated for IOU capacity bidding (CBP) PDR resources. Table 3-21 summarizes the program and portfolio adjusted ex ante demand reduction capability by forecast year for different planning conditions. The tables reflect dispatchable demand reductions available from 4 pm to 9 pm under August worst conditions for 1-in-2 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 2024 conditions. Enrollments are assumed to stay flat through the last year of ELRP approval in 2027.

Table 3-21: ELRP B.2 Ex Ante Impacts for 1-in-2 August Worst Day (MW)

Year	Sites	CAISO		PG&E	
		Program	Portfolio Adj	Program	Portfolio Adj
2024	317	1.19	1.17	1.27	1.25
2025	108	0.38	0.37	0.40	0.40
2026	108	0.38	0.37	0.40	0.40
2027	108	0.38	0.37	0.40	0.40

3.4.12 Comparison of Ex Post and Ex Ante Load Impacts

Table 3-22 compares the demand reductions from 2024 A.1 events. Results are shown for the 4pm to 9pm resource adequacy window and compared to the average of the weekday events used in modeling ex-ante. Between 2022 and 2024, A.1 ELRP customers delivered 3.0% in load reductions for the average event window. Differences in ex ante and ex post counterfactual loads (Load without DR) are largely explained by the change in the enrollment population from PY 2024 ex post enrollment as compared to PY 2025 ex ante. Essentially, the average customer load was lower in PY 2024 relative to the average across the three prior years. 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 3-22: ELRP A1 Comparison of Ex Post and Ex Ante Load Impacts

Result Type	Day Type	Period	Load without DR (avg site kWh/h)	Load Reduction (avg site kWh/h)	% Reduction	Event Avg Temp (F)
Ex Post	Avg Weekday Event	All Hours with Event Dispatch	93.85	1.88	2.0%	96.3
Ex Post	Avg Weekday Event	4 to 9pm	82.80	1.09	1.3%	96.1
Ex Ante (CAISO)	Aug Worst Day, 1-in-2	Resource Adequacy: 4 to 9pm	56.02	1.15	2.1%	90.9
Ex Ante (PG&E)	Aug Worst Day, 1-in-2	Resource Adequacy: 4 to 9pm	58.73	1.21	2.1%	93.8

Ex Post impacts reflect significant, incremental impacts, e.g. those used for ex ante impact model.
Historical impacts weighted by number of current participants in a given event.
Ex Ante impacts reflect portfolio impacts.

Table 3-23 compares the demand reductions from 2024 A.4 events. Results are shown for the 5pm to 8pm resource adequacy window and compared to the average of the weekday events used in modeling ex-ante. Technology-enabled subgroups rely on a three-hour window, which is why the resource adequacy window spans from 5pm to 8pm instead of 4pm to 9pm. Essentially, A.4 resources are required to be to provide three hours of reductions, so it is assumed that the kWh reductions will be spread evenly across three hours. The resulting ex ante impact in the three hour window is 3.05 kW per hour.

Table 3-23: ELRP A4 Battery Comparison of Ex Post and Ex Ante Load Impacts

Result Type	Day Type	Period	Load without DR (avg site kWh/h)	Load Reduction (avg site kWh/h)	% Reduction	Event Avg Temp (F)
Ex Post	Avg Weekday Event	All Hours with Event Dispatch	0.00	3.05	N/A	82.0
Ex Post	Avg Weekday Event	4 to 9pm	0.00	3.05	N/A	82.0
Ex Ante (CAISO)	Aug Worst Day, 1-in-2	Resource Adequacy: 4 to 8pm	N/A	3.05	N/A	82.6
Ex Ante (PG&E)	Aug Worst Day, 1-in-2	Resource Adequacy: 4 to 8pm	N/A	3.05	N/A	84.0

Ex Post impacts reflect significant, incremental impacts, e.g. those used for ex ante impact model.
Historical impacts weighted by number of current participants in a given event.
Ex Ante impacts reflect portfolio impacts.

Table 3-24 compares the demand reductions from 2022 A.6 events, since no events were called in PY 2024. 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 2024 ex ante, with moderate differences due to a slight decrease in enrollments in 2024.

Table 3-24: ELRP A6 Residential Comparison of Ex Post and Ex Ante Load Impacts

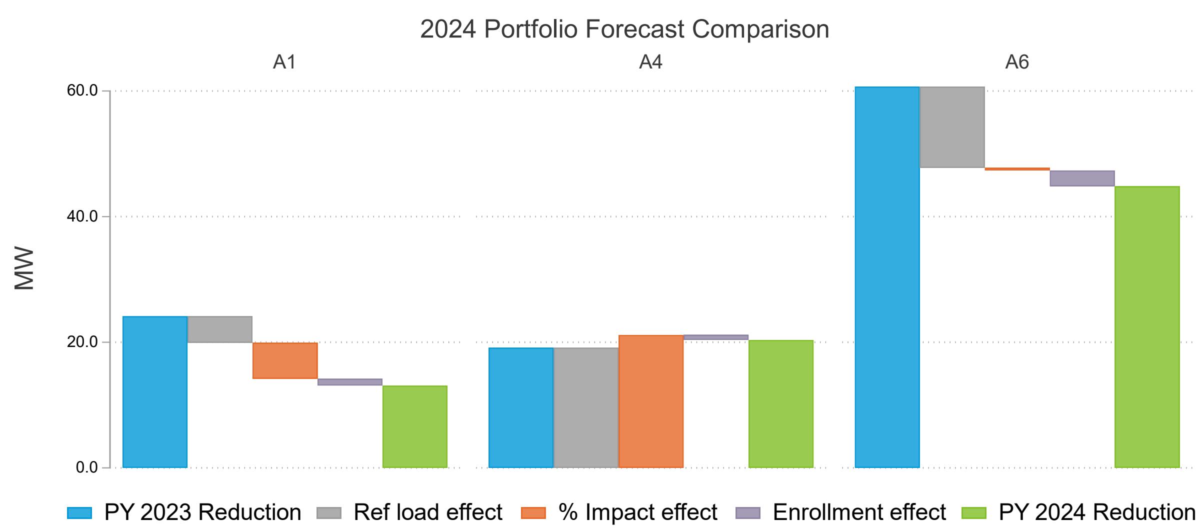
Result Type	Day Type	Period	Load without DR (avg site kWh/h)	Load Reduction (avg site kWh/h)	% Reduction	Event Avg Temp (F)
Ex Post	Avg Weekday Event	All Hours with Event Dispatch	1.26	-0.04	-3.2%	82.9
Ex Post	Avg Weekday Event	4 to 9pm	2.09	0.10	4.6%	92.6
Ex Ante (CAISO)	Aug Worst Day, 1-in-2	Resource Adequacy: 4 to 9pm	1.40	0.03	1.9%	85.7
Ex Ante (PG&E)	Aug Worst Day, 1-in-2	Resource Adequacy: 4 to 9pm	1.66	0.03	1.9%	88.0

Ex Post impacts reflect significant, incremental impacts, e.g. those used for ex ante impact model.
Historical impacts weighted by number of current participants in a given event.
Ex Ante impacts reflect portfolio impacts.

3.4.13 Comparison to 2023 Ex Ante Impact Estimates

The following figure gives a breakdown of the difference in ex ante impact estimates from PY2023 and those generated in in PY2024. The graphs can be interpreted as the individual factors (changes in reference load, percent impacts, or enrollments) that explain the change in the estimated ex ante MW impacts in PY2023 (in blue) and PY2024 (in green).

Figure 3-3: Waterfall Analysis of 2023-2024 Ex Ante Impacts by Key Group



The A.1 group estimates primarily changed due to the lower reference load, which is attributable to a smaller average participant, and an update in impact modeling. Last year, the PY 2022 impacts were leveraged to construct the A.1 ex ante estimates, but this year we used impacts from PY 2022 – PY 2024. For A.6, the reference loads decreased slightly, and the impacts remained similar. This is due to a change in the geographic dispersion of the enrollment forecasts.

3.4.14 Ex Ante Load Impact Slice-of-Day Tables

Table 3-25, Table 3-26, Table 3-27, Table 3-28, Table 3-29, Table 3-30, Table 3-31, and Table 3-32 show the 2024 ex ante aggregate hourly impacts by ELRP Group for each month under PG&E 1-in-2 monthly worst day 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 shoulder months. Reductions are only included for May through October, corresponding to the months in which ELRP events can be called. For Group A.4 and A.5, response to an event is flat across the three-hour Resource Adequacy window to reflect consistent discharge. The pre- and post-event charging are also modelled, but these are not factored into the resource adequacy window. For other groups, however, event response varies by hour.

Table 3-25: ELRP A.1 Slice of Day Table for Monthly Worst Day (Portfolio-Adjusted Aggregate Impacts, MW)

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	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	0.00	0.00	12.87	13.21	13.17	12.95	11.42	0.00	0.00
18	0.00	0.00	0.00	0.00	11.20	12.80	13.13	13.10	12.89	11.48	0.00	0.00
19	0.00	0.00	0.00	0.00	11.36	12.78	13.09	13.04	12.86	11.65	0.00	0.00
20	0.00	0.00	0.00	0.00	11.53	12.97	13.26	13.18	12.99	11.74	0.00	0.00
21	0.00	0.00	0.00	0.00	11.38	12.83	13.11	13.01	12.80	11.50	0.00	0.00
22	0.00	0.00	0.00	0.00	11.00	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 3-26: ELRP A.1-BIP Slice of Day Table for Monthly Worst Day (Portfolio-Adjusted Aggregate Impacts, MW)

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

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

Table 3-27: ELRP A.2 Slice of Day Table for Monthly Worst Day (Portfolio-Adjusted Aggregate Impacts, MW)

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

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

Table 3-28: ELRP A.2-BIP Slice of Day Table for Monthly Worst Day (Portfolio-Adjusted Aggregate Impacts, MW)

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	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	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
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 3-29: ELRP A.4 Slice of Day Table for Monthly Worst Day (Portfolio-Adjusted Aggregate Impacts, MW)

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	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	0.00	-7.28	-7.33	-7.35	-7.36	-7.41	-7.41	0.00	0.00
18	0.00	0.00	0.00	0.00	20.15	20.30	20.35	20.36	20.52	20.52	0.00	0.00
19	0.00	0.00	0.00	0.00	20.15	20.30	20.35	20.36	20.52	20.52	0.00	0.00
20	0.00	0.00	0.00	0.00	20.15	20.30	20.35	20.36	20.52	20.52	0.00	0.00
21	0.00	0.00	0.00	0.00	-5.64	-5.69	-5.70	-5.70	-5.75	-5.75	0.00	0.00
22	0.00	0.00	0.00	0.00	-4.36	-4.39	-4.40	-4.41	-4.44	-4.44	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: ELRP A.5 Slice of Day Table for Monthly Worst Day (Portfolio-Adjusted Aggregate Impacts, MW)

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

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

Table 3-31: ELRP A.6 Slice of Day Table for Monthly Worst Day (Portfolio-Adjusted Aggregate Impacts, MW)

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	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	0.00	0.00	39.20	40.59	39.13	36.03	18.90	0.00	0.00
18	0.00	0.00	0.00	0.00	32.27	45.06	46.44	45.02	41.96	24.92	0.00	0.00
19	0.00	0.00	0.00	0.00	35.88	48.20	49.53	48.16	45.21	28.77	0.00	0.00
20	0.00	0.00	0.00	0.00	36.10	47.37	48.57	47.29	44.59	29.55	0.00	0.00
21	0.00	0.00	0.00	0.00	34.87	44.68	45.71	44.60	42.26	29.17	0.00	0.00
22	0.00	0.00	0.00	0.00	32.98	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: ELRP B.2 Slice of Day Table for Monthly Worst Day (Portfolio-Adjusted Aggregate Impacts, MW)

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	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	0.00	0.00	1.26	1.27	1.25	1.21	1.02	0.00	0.00
18	0.00	0.00	0.00	0.00	1.15	1.28	1.29	1.27	1.23	1.05	0.00	0.00
19	0.00	0.00	0.00	0.00	1.19	1.33	1.34	1.31	1.28	1.09	0.00	0.00
20	0.00	0.00	0.00	0.00	1.21	1.35	1.36	1.33	1.29	1.10	0.00	0.00
21	0.00	0.00	0.00	0.00	1.14	1.27	1.28	1.25	1.21	1.02	0.00	0.00
22	0.00	0.00	0.00	0.00	1.03	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

Most of the non-residential ELRP pilots did not deliver statistically significant demand reductions in PY 2024 while the A.4 residential battery storage pilot did deliver substantial significant savings. For other 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 or PY 2024 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 and PY 2024. Even for technology enabled dispatch such as A4, reductions were lower in PY 2023 and PY 2024 on one event when notifications were sent after the beginning of the event. 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.

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 2024 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.

Most sites did not require individual site regressions, as a comparable control group was available to estimate event-day counterfactuals. Among sites that did require the individual regressions, loads were often variable or the sites were located in areas with few similar sites. The tables below report the bias and fit metrics for the models used by subgroup. Mean absolute percent error (MAPE) indicates the percent difference between predicted values and actual kWh on non-event days in summer 2024. The average percent bias is the mean of the percent errors – without taking an absolute value, this becomes the mean of both positive and negative values, with strong models calibrated to achieve a bias close to zero.

Table A-2: Bias and Fit Measures for Individual Customer Regressions

Subgroup	Sites in Sample	Sites w/ Indiv. Regressions	Avg. kW	Mean Absolute Percent Error (MAPE)	Avg. Percent Bias
A.1	10,702	2,341	-3143.9	0.080	0.001
A.1 BIP	10	9	[redacted]		
A.2	11	11			
A.2 BIP	21	20	1125.9	0.026	-0.034
A.5	4	1	[redacted]		
B.2	313	288	1384.6	0.060	0.002

B. PROXY DAY SELECTION

For the differences-in-differences estimates, participants are compared both over time (event days vs. non-event days) and with a pool of similar, non-participant customers (the matched control group). Proxy days, the non-event days used for comparison, are selected to be as similar as possible to actual event days. In general, these are often the hottest non-holiday weekdays of the summer (e.g. ELRP events are often called on days with extreme weather).

Proxy days are selecting by matching participants pre-event loads on event days (through 2 p.m.) to loads for the same hours on non-event days. Matches are tested and selected as the group that minimizes bias between the event day and non-event day loads.

A t-test can show the likelihood that two data series in fact different from each other. For proxy day selection, better matches should produce results with a higher probability that the two series are not different from each other.

The following tables report the p-values from t-tests of the hypothesis that pre-event hour loads on event days and proxy days are the same. Values are generally very close to one, meaning the hypothesis of similar loads cannot be rejected and the series are in fact very similar.

Table A 0-3: Proxy and Event Day Matching: p-Values from t-Tests

Event date	A.1	A.4
7/10/2024	-	0.667
7/11/2024	-	0.058
7/24/2024	0.015	0.218
9/4/2024	-	0.511
9/5/2024	-	0.190
9/6/2024	-	0.126
9/9/2024	-	0.619

Some smaller values are found in some of the September events for A.4. These event days were more extreme, so some difference with the best proxy days can be expected. At certain levels, the T-tests in fact imply the hypothesis of similar loads can be rejected (e.g. September 5^{th} and 6^{th} have significant differences at the 5% level).

Even if very closely matching proxy days cannot be found, differences-in-differences can still be the best estimation method for a DR evaluation. In such cases, dissimilarities between event days and proxy days may simply mean that the event days are very different from other summer days. Differences-in-differences then would still allow for comparison to a control group on these very hot days, with the control group serving as a proxy for the types of loads seen on those extreme days. This is evidenced by Figure A 0-1, where the control sites closely mirror the participant sites prior to event dispatch.

Figure A 0-1: A.4 Treatment and Control Customers on Event Days