FINAL REPORT

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2022 Load Impact Evaluation for San Diego Gas and Electric's Residential Emergency Load Reduction Pilot

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

This study quantifies the demand impacts of San Diego Gas and Electric's Residential Emergency Load Reduction Pilot. The study focuses on two primary research questions: What were the 2022 demand reductions due to dispatch operations? What is the magnitude of dispatchable load reduction capability for 1-in-2 and 1-in-10 weather planning conditions?

The Residential Emergency Load Reduction Program (ELRP) pilot is a behavioral demand response program with direct settlements and performance payments to participants, not unlike the Reduce Your Use Peak Time Rebate (RYU-PTR) program that ran from 2013 to 2018. The pilot was rolled out in May of 2022 upon direction by the Commission to capture residential emergency load reduction resources, and is currently planned to operate from 2022 through 2025.

Residential ELRP events are triggered by CAISO as an emergency resource during times of extreme grid stress. Ten events were called in August and September of 2022, all from 4 to 9 pm. The average PY 2022 weekday 4 to 9pm event produced 11.91 MW of load reduction.

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1 EXECUTIVE SUMMARY

The Residential Emergency Load Reduction Program (ELRP) pilot is a behavioral demand response program with direct settlements and performance payments to participants, not unlike the Reduce Your Use Peak Time Rebate (RYU-PTR) program that ran from 2013 to 2018. The pilot was rolled out in May of 2022 upon direction by the Commission to capture residential emergency load reduction resources, and is currently planned to operate from 2022 through 2025. As its name implies, Residential ELRP is an out of market emergency resource. It is a subgroup (group A.6) of the broader Emergency Load Reduction Program. The other groups (A.1, A.2, A.3, A.4, A.5, and Group B) are designed for both large commercial and industrial customers and aggregators of residential and non-residential resources including battery storage and other behind the meter dispatchable generation. All ELRP groups including the Residential A.6 group remunerate participant performance via a $2/kWh payment, determined using baseline settlement rules specific to each subgroup. However, the eligibility, targeting, and rollout of the each subgroup are entirely different. Residential ELRP is currently marketed to SDG&E residential customers as the Power Saver Rewards Program.

This study analyzes two primary research questions:

- What were the 2022 demand reductions due to dispatch operations?
- What is the magnitude of dispatchable load reduction capability for 1-in-2 and 1-in-10 weather planning conditions?

Table 1-1 summarizes the estimated ex post demand reductions for the average weekday Residential ELRP event.

Table 1-1: Summary of Average 2022 Ex Post Demand Reductions

Intervention	Sites	Load without DR (MW)	Load reduction (MW)	% Reduction
Residential ELRP (Avg weekday event)	525,382	628.16	11.91	1.9%

Table 1-2 summarizes the residential ELRP dispatchable ex ante reductions under August monthly peaking conditions for a 1-in-2 weather year. The results are shown under both CAISO and SDG&E peaking conditions and reflect the reduction capability from 4pm to 9pm, which aligns with resource adequacy requirements. The SDG&E weather ex ante prediction for 2022 is slightly higher than the ex post reduction because the average ex ante temperature during the 4pm to 9pm event window is about 4 degrees higher than the temperature observed during the average PY 2022 weekday event. For both CAISO and SDG&E weather conditions, demand reductions are expected to increase with the increase in site enrollments. As enrollment forecasts flatten and drop slowly after 2029, reductions begin to decrease as participants slowly decrease. Though the pilot is currently planned to end in 2025, the forecast provided for subsequent years is an estimate of reductions were the pilot to continue or be converted to a program.

Table 1-2: Summary of Ex ante Dispatchable Demand Reductions, 1-in-2 Weather Conditions

Year	Residential ELRP		
	Sites	MW (CAISO)	MW (SDG&E)
2022	540,636	12.64	12.86
2023	542,245	12.81	13.07
2024	544,702	13.08	13.38
2025	547,226	13.34	13.70
2026	549,815	13.61	14.02
2027	552,470	13.88	14.34
2028	555,070	14.15	14.66
2029	555,099	14.24	14.77
2030	553,868	14.24	14.78
2031	552,657	14.24	14.79
2032	551,473	14.24	14.80
2033	550,315	14.24	14.81

2 INTRODUCTION

The Residential Emergency Load Reduction Program (ELRP) pilot is a behavioral demand response program with direct settlements and performance payments to participants, not unlike the Reduce Your Use Peak Time Rebate (RYU-PTR) program that ran from 2013 to 2018. The pilot was rolled out in May of 2022 upon direction by the Commission to capture residential emergency load reduction resources, and is currently planned to operate from 2022 through 2025. As its name implies, Residential ELRP is an out of market emergency resource. It is a subgroup (group A.6) of the broader Emergency Load Reduction Program. The other groups (A.1, A.2, A.3, A.4, A.5, and Group B) are designed for both large commercial and industrial customers and aggregators of residential and non-residential resources including battery storage and other behind the meter dispatchable generation. All ELRP groups including the Residential A.6 group remunerate participant performance via a $2/kWh payment, determined using baseline settlement rules specific to each subgroup. However, the eligibility, targeting, and rollout of the each subgroup are entirely different. Residential ELRP is currently marketed to SDG&E residential customers as the Power Saver Rewards Program.

2.1 PROGRAM BACKGROUND

Residential ELRP enrollments consist of defaults and opt-ins across three basic eligibility groups. Customers receiving Behavioral Demand Response (BDR) treatment and those on discounted CARE or FERA rates were defaulted onto Residential ELRP on May 1, 2022. All other customers opted into Residential ELRP participation. All default and opt-in participants were subject to the following eligibility criteria:

- The customer is not simultaneously enrolled in another supply-side DR program offered by an IOU, third-party DRP, or CCA;
- The customer is not served by a CCA which has elected to exclude its customers from participation in ELRP; and
- The customer must have hourly meter data.

No CCAs have yet elected to exclude their customers from Residential ELRP, so the PY 2022 evaluation includes CCA customers.

As summarized in Figure 2-1, two additional behavioral interventions were also deployed statewide to all customers, and so affected both ELRP participants and non-participants. Flex alerts were deployed on all of the residential ELRP event days. An emergency notice was also pushed to cellphones statewide on September 6. Notably, both treatment and control were exposed to these treatments because they were administered statewide. As such the reductions measured by this evaluation reflect the effect of enrollment in ELRP, incremental to the statewide interventions. Given the exceptional nature of the statewide emergency alert in particular, the effect of that intervention were also investigated.

Figure 2-1: Three Overlapping Behavioral Interventions

1	**Power Saver Rewards (ELRP A6)** – Customers were paid $2/kWh and received notices via email or text. Low income (CARE) and Behavioral DR customers were defaulted onto the program, and any eligible SDG&E customer could volunteer to join.
2	**Flex Alerts** – A statewide mass market campaign that encourage everyone, whether or not they were eligible for ELRP payments, to reduce of shift load away from 4-9 pm of Flex Alert event days
3	**Emergency Notice -** On September 6, 2022 the State issued an emergency notices that buzzed all mobile phones.

2.2 STUDY RESEARCH QUESTIONS

Table 2-1 summarizes the key research questions for each intervention.

Table 2-1: Key Research Questions

	Research Question
1	What were the demand reductions due to program operations and interventions in 2022 – 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 eligibility group (default BDR, default discounted rates, opted-in) during PY 2022?
4	What are the ex ante load reduction capabilities for 1-in-2 and 1-in-10 weather conditions? And how well does it align with ex post results?
5	What concrete steps or experimental tests can be undertaken to improve program performance?
6	What was the load impact of the statewide emergency alert on September 6, incremental to the impacts attributable to residential ELRP?

2.3 OVERVIEW OF METHODS

The primary challenge of impact evaluation is the need to accurately detect changes in energy consumption while systematically eliminating plausible alternative explanations for those changes, including random chance. Did Residential ELRP events cause a change in critical peak period demand? Or can the differences be explained by other factors? To estimate energy savings, it is necessary to estimate what energy consumption would have been in the absence of the intervention—the counterfactual or reference load.

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

- **Matched control tournament:** In order to identify the control pool sites that best matched each participant's energy use patterns on event-like proxy days (similar in weather and system conditions to event days), several matching methods were tested. These methods included different matching algorithms (e.g. Euclidean and propensity matching) and different site characteristics to be used in the matching. Matching methods included different combinations of proxy day load characteristics such as load factor, load shape, and site weather sensitivity. Control candidates were also "hard-matched" on climate zone, net metering status, and size bin[1].
- **Difference in-differences model with event and non-event days and participants and matched controls:** The data was structured with participant loads pre- and post-intervention and control loads pre- and post-intervention side by side. Per site load impacts were estimated with difference-in-differences to net out exogenous differences between treatment and control that existed prior to the intervention.
- **Within-subjects time-series model for participants to estimate statewide emergency alert effects:** Because the intervention was deployed statewide, no control group was available. The data was structured as average participant loads for the full summer of PY 2022. A spline weather model was constructed using a primary weather variable selected from among ten variables. A same-day adjustment was applied to further minimize prediction error. Estimates for non-emergency FLEX alerts were also attempted using the same methodology but were much smaller in magnitude and exhibited greater uncertainty than the emergency alert impacts and are therefore not presented in this report.

Figure 2-2 summarizes the out of sample testing process used to select the matched controls to be used for modeling. Essentially, the out of sample process is an iterative approach whereby data is systematically left out of the matching model then used to assess matching method performance—a

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

well performing model should produce matches for loads on days which were not used for the model. The final model is identified based on least bias (% Bias) and best fit (Relative RMSE) metrics.

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

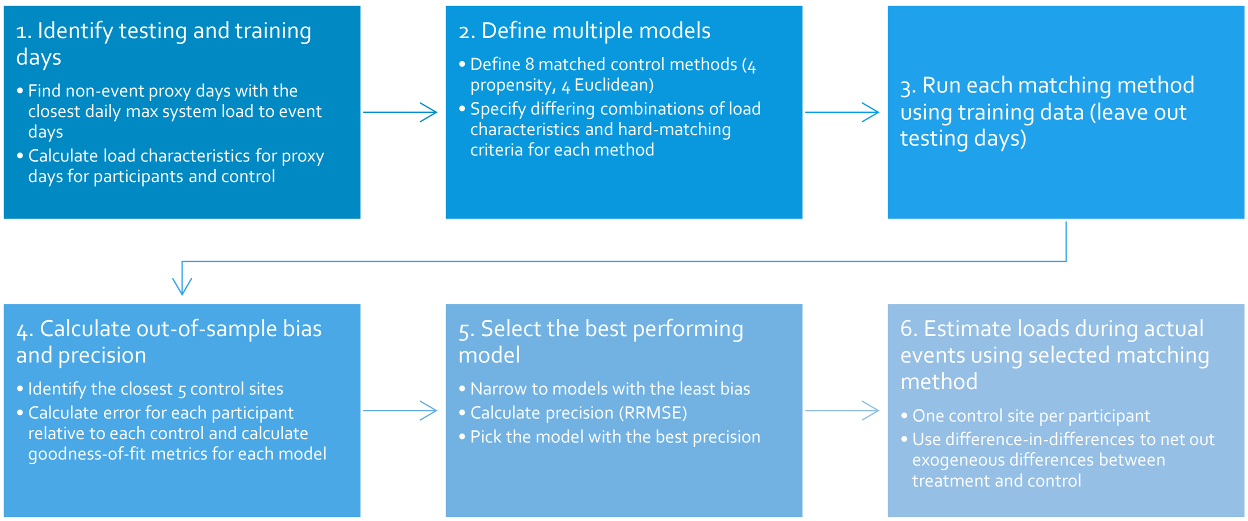


Figure 2-3 below demonstrates the mechanics of a difference in difference calculation. In the first panel, average observed loads on proxy days are shown for participants and for their matched controls. The difference between these two is the first "difference" and quantifies underlying differences between participants and their controls not attributable to event participation. Note that this first difference is very small, indicative of a high quality match and sufficient sample size to neutralize the noise inherent in individual customer loads. The second panel shows the average observed participant and matched control loads on event days. The gap between these two is the second difference which includes both the difference due to event participation as well as the underlying first difference observable on non-event days. The third panel shows the average event day loads after netting out the proxy day difference from the event day control load. The result is the difference in difference impact.

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

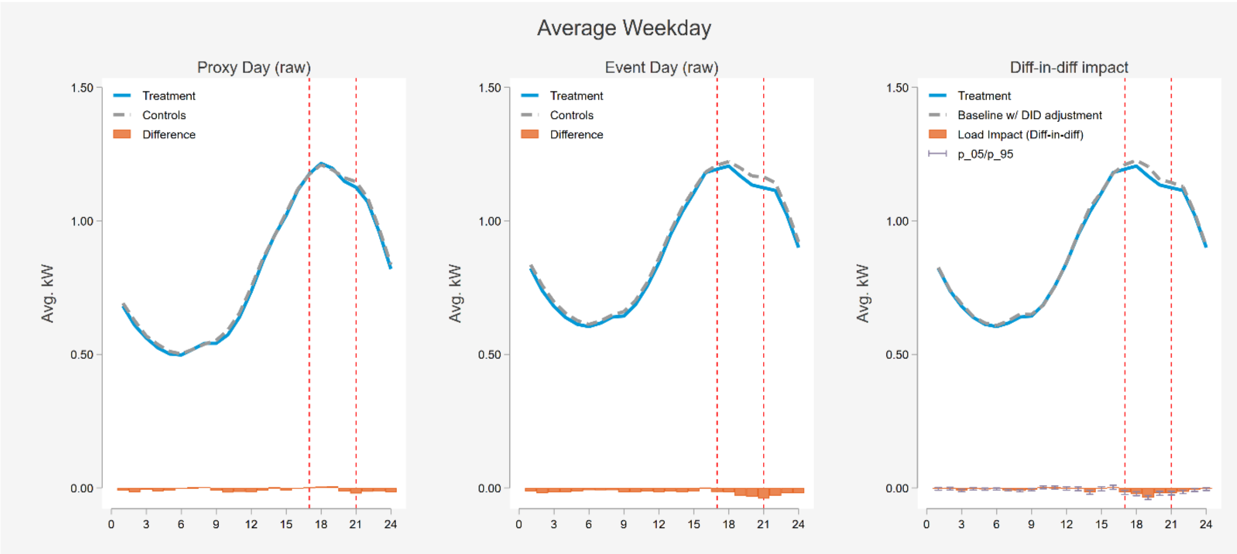


Table 2-2 summarizes the data sources, segmentation, and estimation methods used for each program. The segmentation was defined in advance of the analysis and is of particular importance because the evaluation used a bottom up approach to estimate impacts and to ensure that aggregate impacts across segments equaled the sum of the parts. Because impacts for each segment were added together, the segmentation was structured to be mutually exclusive and completely exhaustive. In other words, every customer was assigned to exactly one segment. The primary segmentation variable was eligibility group, given the substantial difference in impact expected for default versus opt-in enrollment. In addition, 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. Segmentation also included solar/net metering status. 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 2-2: Evaluation Methods

Evaluation Element	Residential ELRP	Statewide Emergency Alert
Data sources / samples	▪ All event season data for the past program year for ✓ a sample of 41k Residential ELRP participants ✓ a control pool of 52k non participants. Customers recently on CARE / FERA but not affected by the May 1 default ELRP rollout	▪ All event season data for the past program year for ✓ a sample of 41k Residential ELRP participants

Evaluation Element	Residential ELRP	Statewide Emergency Alert
	were used as the control pool for the CARE / FERA group	
Segmentation	▪ Eligibility Group ✓ Default BDR ✓ Default CARE / FERA ✓ Opted-in ▪ Climate zone (Coastal vs Inland) ▪ Solar/NEM status	▪ N/A
Estimation method: Ex-post	▪ Difference-in-differences with matched control sites	▪ Within-subjects time-series regression for the average residential ELRP participant
Estimation method: Ex-ante	▪ Weather normalized customer regressions by segment for reference loads ▪ Regression of historical event percent impacts versus weather for percent reductions	▪ N/A

All analyses were conducted using a sample of participants. Population weighting was applied to reconstruct the participant population as was observed in mid-August shortly before the first event was called on August 17.

Table 2-3: Enrolled August PY 2022 Population Used for Weighting

Eligibility Group	NEM	Enrolled population (Aug 2022)
BDR (not on CARE)	Yes	8,813
BDR (not on CARE)	No	225,235
CARE (includes linked to BDR)	Yes	4,077
CARE (includes linked to BDR)	No	298,439
Self-enroll (Opt-in eligible)	Yes	151
Self-enroll (Opt-in eligible)	No	3,921
TOTAL		540,636

3 RESIDENTIAL ELRP EVENT DAY IMPACTS

Emergency Load Reduction Program (ELRP) participants receive day ahead event notifications via email and can also opt-in to text notifications. Participants and non-participants were also exposed to statewide flex and emergency alert interventions so residential ELRP reductions are incremental to those impacts. Ex post estimates for the statewide emergency alert have also been estimated for residential ELRP participants to quantify the additive impact of both interventions.

3.1 EVENT CHARACTERISTICS

Residential event impacts were assessed by site (premise and service point combination). Sites were grouped together into segments to assess potential differences in impacts for various groups. The segmentation, summarized in Table 3-1, was developed based on eligibility group, climate zone, and net metering status which may influence impacts. The analysis was performed at the segment level so these granular impacts could therefore be summed, yielding aggregate impacts in addition to the segment specific impacts.

The segmentation criteria were defined as follows:

- **Eligibility Group:** was the customer enrolled on a default or opt-in basis? For default enrollees, was the customer in BDR or on CARE / FERA rates[2]?
- **Climate zone:** in which SDG&E climate zone was the site located?
- **NEM status**: did the site have net metering?

Table 3-1: Participant Populations

Eligibility Group	NEM	Climate Zone	Total Population	Sites in analysis
BDR	No	Coastal	145,133	4,643
		Inland	80,102	2,556
	Yes	Coastal	4,480	4,003
		Inland	4,333	3,926
CARE/FERA	No	Coastal	155,471	7,278
		Inland	142,968	7,055
	Yes	Coastal	1,573	1,054
		Inland	2,504	1,909
Opted-in	No	Coastal	2,565	2,214
		Inland	1,356	1,201

[2] including those on BDR, to keep segments mutually exclusive and exhaustive

Eligibility Group	NEM	Climate Zone	Total Population	Sites in analysis
	Yes	Coastal	89	73
		Inland	62	53
All study segments			**540,636**	**35,965**

Table 3-1 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 in each segment to which the sample was weighted. Note that these counts are for the August 17 event. Counts diminished for subsequent event in small part due to unenrollments and in large part due to outages that affected roughly 5% of customers during the extreme weather that coincided with the PY 2022 events. While the default CARE / FERA group is split relatively evenly by climate zone, the coastal climate zone is overrepresented in both the BDR and the Opted-in groups. In the coastal climate zone, cooling loads and therefore impacts per site are expected to be lower. About 4% of default BDR and Opted-in sites are net-metered, compared to about 1.5% of default CARE / FERA sites, but it was important to estimate impacts separately for this segment given the difference in underlying load shapes typical of solar customers.

Table 3-2 shows the 10 PY 2022 Residential ELRP event days. On the September 6 event, an emergency alert was also pushed to also cell phones statewide by the California Independent System Operator (CAISO) to provide exceptional emergency relief. Of the ten events called, nine consecutive events were called beginning on the Thursday before Labor Day and ending on the Friday after Labor Day. Seven events occurred on weekdays and three occurred on weekends or holidays. Daily maximum temperatures ranged from 83.6 to 95.0 F.

Table 3-2: Residential ELRP Events in 2022

Event date	Day of week	Event start	Event end	Daily max temp (F)	Max SDG&E system load (MW)
8/17/2022	Wednesday	4:00 pm	9:00 pm	83.6	3,738
9/1/2022	Thursday	4:00 pm	9:00 pm	89.6	4,483
9/2/2022	Friday	4:00 pm	9:00 pm	91.1	4,301
9/3/2022	Saturday	4:00 pm	9:00 pm	95.0	4,406
9/4/2022	Sunday	4:00 pm	9:00 pm	89.3	4,168
9/5/2022	Monday	4:00 pm	9:00 pm	89.7	4,201
9/6/2022*	Tuesday	4:00 pm	9:00 pm	89.5	4,322
9/7/2022	Wednesday	4:00 pm	9:00 pm	92.2	4,633
9/8/2022	Thursday	4:00 pm	9:00 pm	92.3	4,291
9/9/2022	Friday	4:00 pm	9:00 pm	86.5	3,898

*Statewide Emergency Alert also called by CAISO

3.2 DATA SOURCES AND ANALYSIS METHOD

Table 3-3 summarizes the five data sources used to conduct the Residential ELRP event impact analysis. The analysis was done by site on hourly load data. Various data sources were used to classify sites into the study segments. While different segments were developed for the various analyses in this report, the characteristic definitions used to build segments were consistent across analyses.

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

Source	Comments
Hourly interval data	▪ Summer 2022 ▪ All analysis done by site (premise id-service point id pair)
Outage information	▪ PSPS and emergency outage data details which customers and what timeframes were impacted by outages
Customer characteristics	▪ Treatment: Sample of 41k residential ELRP participants ▪ Control: Sample of 52k residential sites not in other DR programs. Customers recently on CARE / FERA but not affected by the May 1 default ELRP rollout were used as the control pool for the CARE / FERA group. ▪ NEM status, climate zones used in matched control selection
SDG&E hourly system loads	▪ Summer 2022 ▪ 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

The primary analysis method was difference-in-differences with matched controls. The distance matching approach selected one matched control site for each of the 41,000 sampled residential ELRP sites among a control candidate pool of roughly 52,000 sampled residential sites who were not enrolled in CPP or other DR programs which might influence energy use and which render a customer ineligible for ELRP. Non-typical, or very large customers tend to be more difficult to match because there are fewer other customers with similar load patterns. To ensure there would be sufficient control candidates for every type of participant, the control pool was constructed within bins by NEM status, CARE / FERA comparability[3], and size (annual usage for non-NEM and system capacity for NEM sites).

[3] Customers recently on CARE / FERA but not affected by the May 1 default ELRP rollout were used as the control pool for the CARE / FERA group

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.

3.3 EX POST LOAD IMPACTS

3.3.1 RESIDENTIAL ELRP IMPACTS BY EVENT

There were 10 residential events called during PY 2022, all from 4 pm to 9pm. Table 3-4 summarizes the load reductions for Residential ELRP sites for the 10 events and for the average weekday and average weekend events. The average weekday event reductions were significant with an average aggregate reduction of 11.91 MW. Reductions for the average weekend event were not significant.

Table 3-4 also summarizes the number of sampled sites for each event day and the estimated total participant population. To derive population totals, sampled participants for the August 17 analysis were scaled to match the 540,636 total population reported in mid-August. This same scaling factor was used for all events. Sample and therefore total counts diminished for subsequent events in small part due to unenrollments and in large part due to outages that affected roughly 5% of customers during the extreme weather that coincided with the PY 2022 events. A participant needs to have data available both for the event and for the relevant proxy day to be included in the estimate for a given event.

Aggregate reductions for significant events range from 18.15 MW (September 2) to 10.53 MW (September 6), with the exception of the September 9 event for which there was a modest increase of -6.72 MW. Weather patterns were substantially anomalous on September 9. Not only was the average event temperature almost 7 degrees below the average, but temperatures decreased steadily during the day as a cooling rainstorm terminated what had been a multi-day extreme heatwave during the preceding event days. In the tables, the orange bars show a visual comparison of the reductions that are numerically labeled on the left of the bars.

Table 3-4: Residential ELRP Program Event Reductions (All Eligibility Groups)

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Sites Sampled	Reductions (Ex Post)			Significant (90% CI)	Significant (95% CI)	Reductions (Baseline)	
					Aggregate (MW)	Average Site (kW)	t-stat			Aggregate (MW)	Average Site (kW)
8/17/2022	4 to 9 pm	74.5	540,636	36,914	13.09	0.02	5.64	Yes	Yes	111.11	0.21
9/1/2022	4 to 9 pm	79.2	525,937	35,957	16.09	0.03	6.19	Yes	Yes	-6.53	-0.01
9/2/2022	4 to 9 pm	79.3	534,092	36,315	18.15	0.03	6.34	Yes	Yes	-6.59	-0.01
9/6/2022	4 to 9 pm	79.1	518,955	35,546	10.53	0.02	3.59	Yes	Yes	-28.64	-0.05
9/7/2022	4 to 9 pm	80.9	522,857	35,700	16.22	0.03	5.49	Yes	Yes	-88.04	-0.17
9/8/2022	4 to 9 pm	85.4	522,061	36,059	14.65	0.03	4.83	Yes	Yes	9.71	0.02
9/9/2022	4 to 9 pm	71.8	513,576	35,263	-6.72	-0.01	-2.78	Yes	Yes	198.12	0.38
Avg Weekday Event	**4 to 9 pm**	**78.4**	**525,382**	**35,965**	**11.91**	**0.02**	**7.12**	**Yes**	**Yes**	**27.02**	**0.05**
9/3/2022	4 to 9 pm	87.9	508,068	34,694	2.77	0.01	0.74	No	No	-164.08	-0.32
9/4/2022	4 to 9 pm	81.7	521,701	35,818	2.85	0.01	0.83	No	No	-126.57	-0.24
9/5/2022	4 to 9 pm	79.4	538,895	36,897	-1.80	0.00	-0.54	No	No	-152.25	-0.29
Avg Weekend Event	**4 to 9 pm**	**82.8**	**522,652**	**35,803**	**-0.63**	**0.00**	**-0.21**	**No**	**No**	**-147.64**	**-0.28**

*Includes results from all eligibility groups and both NEM and non-NEM customers

**Baseline reductions included as a basis for comparison and are not the primary focus of this evaluation

Estimated load reductions using the baseline method for settlements are presented in the far right columns of Table 3-4 as a basis for comparison. Baseline load reductions are calculated at the individual account level, then aggregated and scaled to the program population size. The individual baseline methodology produces estimates that are significantly different in both direction and magnitude than the ex post impacts. For example, the baseline method estimates event load reductions as large as 198.12 MW on September 9, whereas the ex post estimate for the same event is -6.72 MW. While the individual baseline is used to remunerate participants due to its simplicity and ease of calculation, it is vulnerable to statistical noise and bias due to the inherent volatility in individual customer loads. Thus ex post impacts are considered to be a more precise and accurate estimate of the true load reduction that occurred. Further detail on the differences between the baseline and ex post methods is provided in Table 3-7: Comparison of Settlement Baseline and Load Impact Evaluation Methodologies.

3.3.2 Residential ELRP Impacts by Eligibility Group

Reductions were also analyzed by eligibility group status for residential ELRP participants for the average 4 pm to 9 pm weekday event. Table 3-5 details the reference loads and load reductions by eligibility group overall and by NEM status and climate zone. In addition to aggregate reductions, average reductions per site are also shown. The reference load for aggregate impacts includes the load across all enrolled sites as recorded at the meter. In aggregate, 1.9% of load was curtailed during the average event.

Unsurprisingly, percent reductions are highest for residential customers that opted-in to ELRP. This population produced reductions of 7.2%, which is substantial for a behavioral intervention. Customers that were defaulted onto residential ELRP and may be less engaged in general and less aware of events in particular, produced percent reductions ranging from 1.4% for BDR customers and 2.6% for customers on CARE / FERA rates. It is notable that customers on CARE / FERA rates produced nearly double the percent impacts compared to BDR customers despite having reference loads that are about 25% lower.

Reference loads are generally substantially higher among participants in the inland climate zone. Percent reductions are also often higher for customers in the inland climate zone because there is more load, especially cooling load, which can be curtailed. This may be the case for the customers that opted-in to ELRP, though the small difference may not be significant. However, for default groups (BDR and CARE / FERA), percent reductions were substantially lower inland that in the coastal climate zone. On average, percent reductions produced by NEM sites are not significantly different than non-NEM sites.

Table 3-5: Residential ELRP Average Weekday Event Reductions by Eligibility Group, NEM, Climate

Eligiblity Group	NEM	Climate Zone	Event Window	Temp	Sites Enrolled	Sites Sampled	Aggregate (MW)				Average Site (kw)			t-stat
							Ref Load	Reduction	% Reduction	Std Error	Ref Load	Reduction	Std Error	
BDR	No	Coastal	4 to 9 pm	77.4	142,236	4,643	175.01	3.08	1.8%	1.42	1.23	0.02	0.01	2.17
		Inland	4 to 9 pm	79.6	78,308	2,556	126.10	1.27	1.0%	1.07	1.61	0.02	0.01	1.19
	Yes	Coastal	4 to 9 pm	77.3	4,329	4,003	5.81	0.05	0.9%	0.07	1.34	0.01	0.02	0.79
		Inland	4 to 9 pm	79.6	4,245	3,926	7.70	0.14	1.9%	0.06	1.81	0.03	0.01	2.27
Total BDR			**4 to 9 pm**	**78.2**	**229,115**	**15,129**	**314.60**	**4.54**	**1.4%**	**1.30**	**1.37**	**0.02**	**0.01**	**3.50**
CARE/FERA	No	Coastal	4 to 9 pm	77.3	145,798	7,278	125.77	5.39	4.3%	0.77	0.86	0.04	0.01	6.96
		Inland	4 to 9 pm	80.0	142,458	7,055	177.97	1.48	0.8%	0.96	1.25	0.01	0.01	1.54
	Yes	Coastal	4 to 9 pm	77.2	1,467	1,054	1.80	0.15	8.2%	0.03	1.23	0.10	0.02	4.37
		Inland	4 to 9 pm	80.1	2,657	1,909	4.84	-0.01	-0.1%	0.06	1.82	0.00	0.02	-0.13
Total CARE / FERA			**4 to 9 pm**	**78.6**	**292,347**	**17,296**	**309.36**	**7.07**	**2.3%**	**1.15**	**1.06**	**0.02**	**0.00**	**6.14**
Opted-in	No	Coastal	4 to 9 pm	77.4	2,472	2,214	2.21	0.15	6.6%	0.03	0.89	0.06	0.01	4.94
		Inland	4 to 9 pm	79.6	1,341	1,201	1.71	0.13	7.9%	0.03	1.28	0.10	0.02	5.10
Total Opted-in*			**4 to 9 pm**	**78.2**	**3,957**	**3,540**	**4.11**	**0.29**	**7.2%**	**0.04**	**1.04**	**0.07**	**0.01**	**6.98**
All Participants			**4 to 9 pm**	**78.4**	**525,382**	**35,965**	**628.16**	**11.91**	**1.9%**	**1.67**	**1.20**	**0.02**	**0.00**	**7.12**

*Includes 144 Opted-in Coastal and Inland sites with NEM not represented in the Opted-in breakout

The average event day load shape is summarized in greater detail in Figure 3-1 for defaulted BDR sites, in

Figure 3-2 for defaulted CARE / FERA sites, and in

Figure 3-3 for opted-in sites. Note that the figures, extracted from the Ex Post Load Impact Table, are for the ELRP residential participant population for the average weekday event. The left panel shows the aggregate hourly loads (actual and counterfactual) for these sites. The right panel shows impacts per site. The tables accompanying each figure show aggregate impacts for the 4 pm to 9 pm weekday event window.

The defaulted BDR load shapes in Figure 3-1 exhibit a very modest 1.4% impact which is relatively consistent for the full event window.

Figure 3-2 shows a somewhat larger average CARE / FERA site reduction of 2.3% for which appears somewhat concentrated from 5 pm to 8 pm.

Figure 3-3 shows a pronounced notching during event hours for the opted-in group. There is a possible snapback effect in hour ending 22 suggesting that some opted-in participants may be responding by adjusting thermostat settings during event hours. Also notable is that reductions appear relatively consistent for the duration of the event window.

Figure 3-1: Residential ELRP Summary for Average Event (Defaulted BDR)

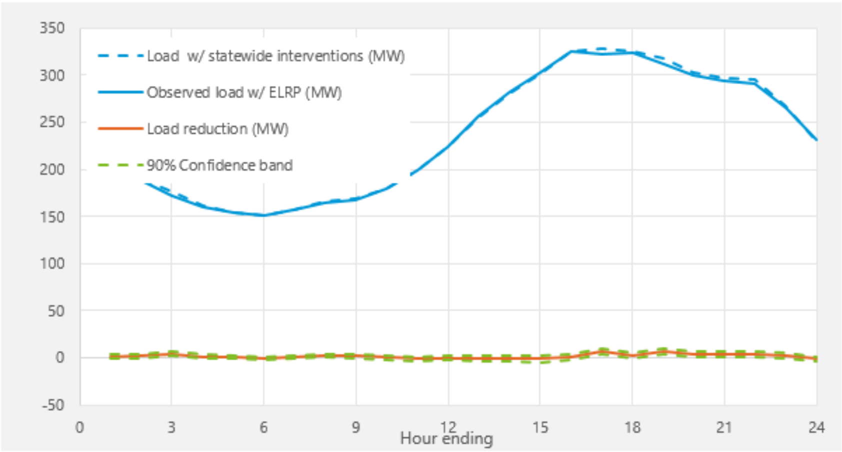
Aggregate (MW)

Table 1: Menu options

Type of results	Aggregate
Category	Eligibility Group
Subcategory	Default - BDR
Event date	Avg. Weekday Event, 4-9pm

Table 2: Event day information

ELRP A6 Event start	4:00 PM
ELRP A6 Event end	9:00 PM
Total enrolled accounts	229,115
Avg ELRP load reduction 4PM-9PM	4.54
% ELRP Load reduction 4PM-9PM	1.4%



Average Customer (kW)

Table 1: Menu options

Type of results	Average Customer
Category	Eligibility Group
Subcategory	Default - BDR
Event date	Avg. Weekday Event, 4-9pm

Table 2: Event day information

ELRP A6 Event start	4:00 PM
ELRP A6 Event end	9:00 PM
Total enrolled accounts	229,115
Avg ELRP load reduction 4PM-9PM	0.02
% ELRP Load reduction 4PM-9PM	1.4%

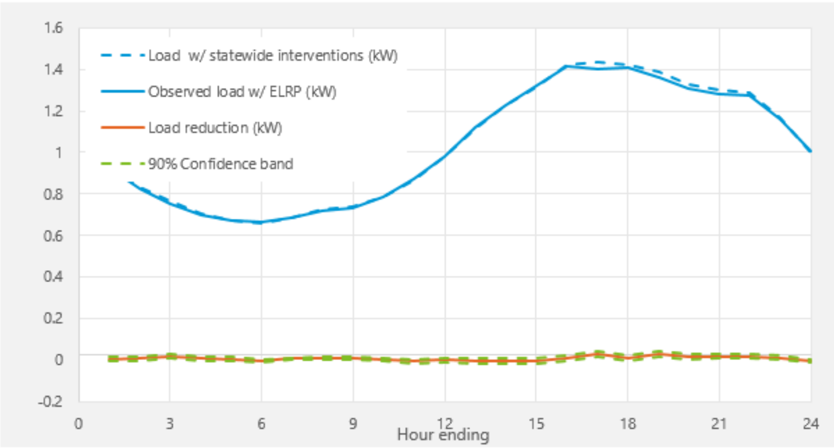


Figure 3-2: Residential ELRP Summary for Average Event (Defaulted CARE / FERA)

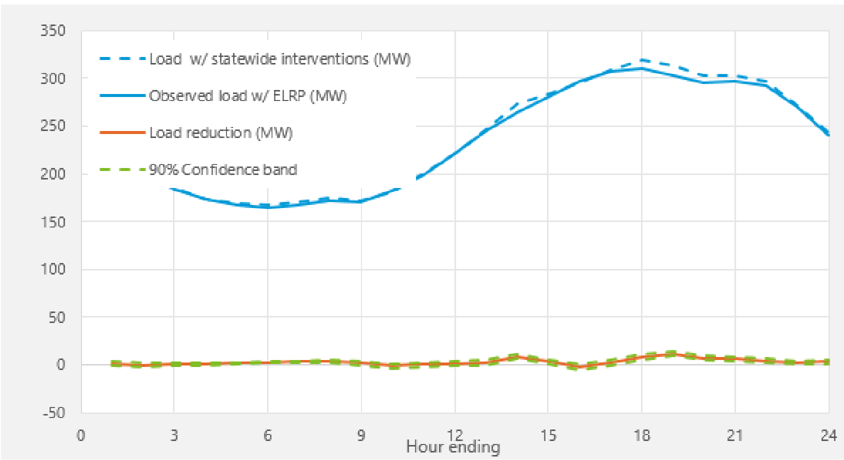
Aggregate (MW)

Table 1: Menu options

Type of results	Aggregate
Category	Eligibility Group
Subcategory	Default - CARE/FERA
Event date	Avg. Weekday Event, 4-9pm

Table 2: Event day information

ELRP A6 Event start	4:00 PM
ELRP A6 Event end	9:00 PM
Total enrolled accounts	292,347
Avg ELRP load reduction 4PM-9PM	7.07
% ELRP Load reduction 4PM-9PM	2.3%



Average Customer (kW)

Table 1: Menu options

Type of results	Average Customer
Category	Eligibility Group
Subcategory	Default - CARE/FERA
Event date	Avg. Weekday Event, 4-9pm

Table 2: Event day information

ELRP A6 Event start	4:00 PM
ELRP A6 Event end	9:00 PM
Total enrolled accounts	292,347
Avg ELRP load reduction 4PM-9PM	0.02
% ELRP Load reduction 4PM-9PM	2.3%

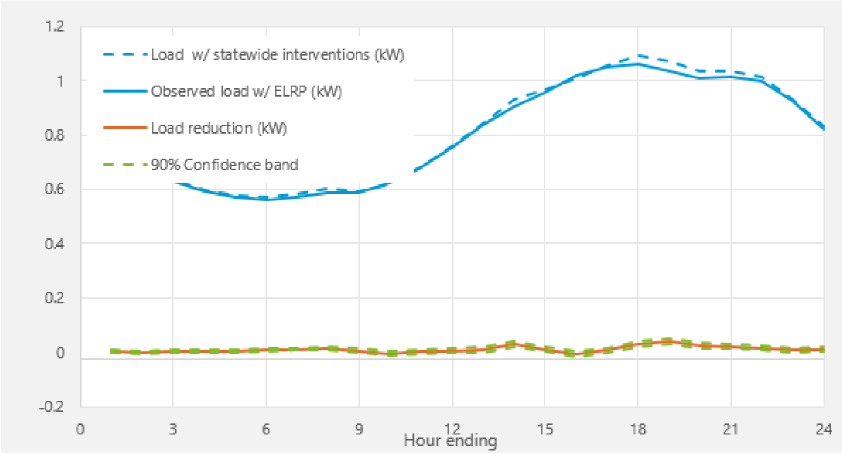


Figure 3-3: Residential ELRP Summary for Average Event (Opted-in)

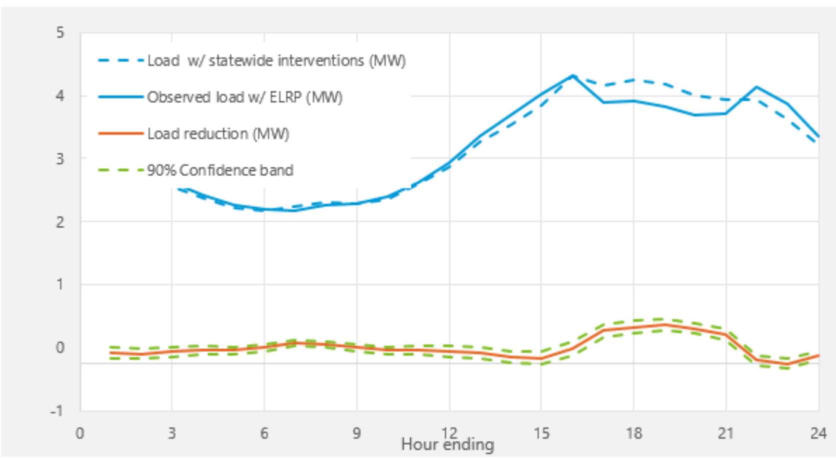
Aggregate (MW)

Table 1: Menu options

Type of results	Aggregate
Category	Eligibility Group
Subcategory	Opted-in
Event date	Avg. Weekday Event, 4-9pm

Table 2: Event day information

ELRP A6 Event start	4:00 PM
ELRP A6 Event end	9:00 PM
Total enrolled accounts	3,957
Avg ELRP load reduction 4PM-9PM	0.29
% ELRP Load reduction 4PM-9PM	7.2%



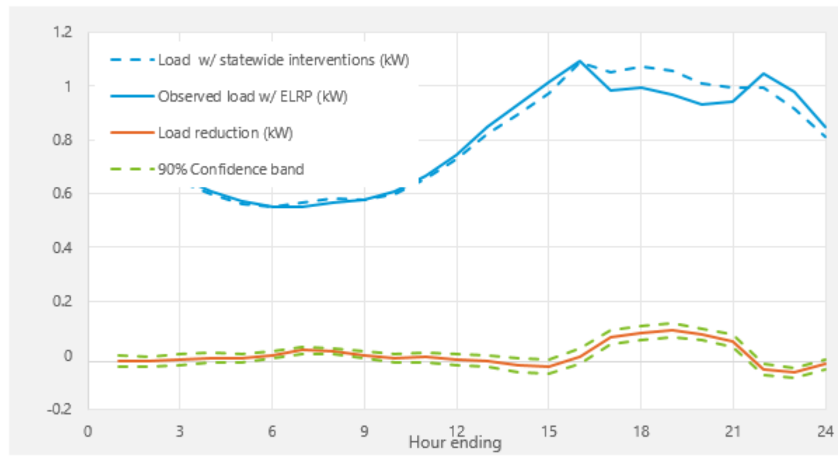
Average Customer (kW)

Table 1: Menu options

Type of results	Average Customer
Category	Eligibility Group
Subcategory	Opted-in
Event date	Avg. Weekday Event, 4-9pm

Table 2: Event day information

ELRP A6 Event start	4:00 PM
ELRP A6 Event end	9:00 PM
Total enrolled accounts	3,957
Avg ELRP load reduction 4PM-9PM	0.07
% ELRP Load reduction 4PM-9PM	7.2%



3.3.3 RESIDENTIAL ELRP IMPACTS BY TOU STATUS

Table 3-6 compares the same results for sites on TOU rates versus those that are not on TOU rates. Almost one-quarter of the enrolled sites are not on Non-TOU rates, and more than two-thirds are on TOU rates. Notably, sites that are not on TOU rates produced percent reductions of 2.6% compared to 1.7% for sites on TOU rates. This suggests that sites on TOU rates may already be shifting load away from peak hours on a daily basis and may have less remaining load available to be shifted in response to ELRP events.

Table 3-6: Residential ELRP Average Weekday Event Reductions by TOU and Eligibility Group

TOU	Eligiblity Group	Event Window	Temp	Sites Enrolled	Sites Sampled	Aggregate (MW)				Average Site (kw)			t-stat
						Ref Load	Reduction	% Reduction	Std Error	Ref Load	Reduction	Std Error	
No	BDR	4 to 9 pm	78.6	39,155	1,550	59.82	1.70	2.8%	0.66	1.53	0.04	0.02	2.58
	CARE/FERA	4 to 9 pm	78.6	87,915	4,418	93.47	2.23	2.4%	0.66	1.06	0.03	0.01	3.40
	Opted-in	4 to 9 pm	78.4	683	611	0.80	0.06	7.3%	0.02	1.17	0.09	0.03	3.35
Total Non-TOU		**4 to 9 pm**	**78.6**	**127,724**	**6,580**	**153.96**	**3.99**	**2.6%**	**0.87**	**1.21**	**0.03**	**0.01**	**4.58**
Yes	BDR	4 to 9 pm	78.1	189,978	13,578	254.87	2.85	1.1%	1.15	1.34	0.01	0.01	2.49
	CARE/FERA	4 to 9 pm	78.6	204,429	12,878	215.89	4.84	2.2%	0.95	1.06	0.02	0.00	5.09
	Opted-in	4 to 9 pm	78.1	3,275	2,929	3.31	0.24	7.1%	0.04	1.01	0.07	0.01	6.14
Total TOU		**4 to 9 pm**	**78.4**	**397,662**	**29,385**	**474.21**	**7.92**	**1.7%**	**1.44**	**1.19**	**0.02**	**0.00**	**5.52**
All Participants		**4 to 9 pm**	**78.4**	**525,382**	**35,965**	**628.16**	**11.91**	**1.9%**	**1.67**	**1.20**	**0.02**	**0.00**	**7.12**

This difference appears to be concentrated within defaulted BDR sites: site not on TOU rates yielded 2.4% reductions compared to 1.1% for sites on TOU rates. Reductions for defaulted CARE / FERA sites and for opted-in sites are not meaningfully different between sites on TOU rates versus those not on TOU rates. Figure 3-4 compares the aggregate load shape for the average weekday event for defaulted BDR customers on TOU rates versus those that are not on TOU rates. The load shape for customers on TOU rates, in the left panel exhibits a much flatter shape during the 4 to 9 pm TOU peak window and shows a small but consistent load reduction for the duration of this window which also aligns with the ELRP event window. The load shape for customers not on TOU rates exhibits more pronounced 4 to 6pm peak and also shows that ELRP reductions are concentrated during this time. This further supports the hypothesis that, at least for defaulted BDR customers, sites on TOU rates may already be shifting load away from peak hours on a daily basis and may have less remaining load available to be shifted in response to ELRP events.

Figure 3-4: Residential ELRP Summary for Defaulted BDR by TOU Status

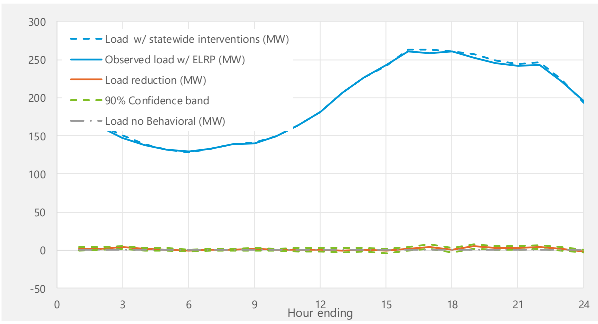
Defaulted BDR on TOU - Aggregate (MW)

Table 1: Menu options

Type of results	Aggregate
Category	TOU & Eligibility
Subcategory	TOU - Default - BDR
Event date	Avg. Weekday Event, 4-9pm

Table 2: Event day information

ELRP A6 Event start	4:00 PM
ELRP A6 Event end	9:00 PM
Total enrolled accounts	189,978
Avg ELRP load reduction 4PM-9PM	2.85
% ELRP Load reduction 4PM-9PM	1.1%



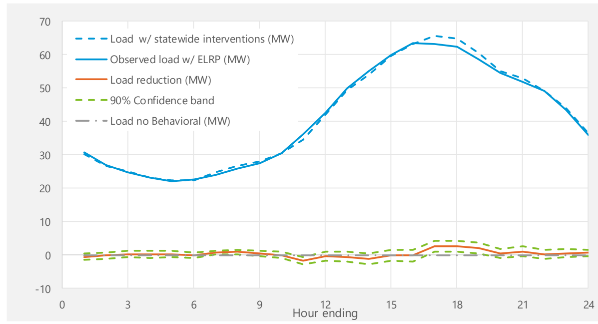
Defaulted BDR on Non-TOU - Aggregate (MW)

Table 1: Menu options

Type of results	Aggregate
Category	TOU & Eligibility
Subcategory	Non-TOU - Default - BDR
Event date	Avg. Weekday Event, 4-9pm

Table 2: Event day information

ELRP A6 Event start	4:00 PM
ELRP A6 Event end	9:00 PM
Total enrolled accounts	39,155
Avg ELRP load reduction 4PM-9PM	1.70
% ELRP Load reduction 4PM-9PM	2.8%



3.3.4 Comparison of Evaluation Load Reductions to Baseline Approach

The Residential ELRP pilot remunerates participant performance via a $2/kWh payment, determined using baseline settlement rules. The baseline rules are applied at the customer account level and differ for weekday and weekend events as follows:

- Weekday events:
  - Calculate the average 4 to 9 pm load for the prior 5 non-event weekdays (excluding holidays).
  - Identify the 3 days with the top load.
  - Take the average hour loads across these top 3 days. This is the baseline for that customer for that event. No adjustment is applied.
  - Subtract observed load from the baseline. This is the load reduction.
  - To determine the kWh eligible for payment, sum up the load reduction during the event window. No payments or penalties apply to totals below zero kWh for an event.
- Weekend events:
  - Calculate the average 4 to 9 pm load for the prior 3 non-event weekend days (including holidays).
  - Identify the 1 day with the top load. This is the baseline for that customer for that event. No adjustment is applied.
  - Subtract observed load from the baseline. This is the load reduction.

- To determine the kWh eligible for payment, sum up the load reduction during the event window. No payments or penalties apply to totals below zero kWh for an event.

The baseline approach is used to determine settlements for participants because it is simple to calculate and simple to explain to customers. Table 3-7 compares the settlement baseline to the difference-in-difference approach used for the load impact evaluation and underscores why the latter is more methodologically robust.

Table 3-7: Comparison of Settlement Baseline and Load Impact Evaluation Methodologies

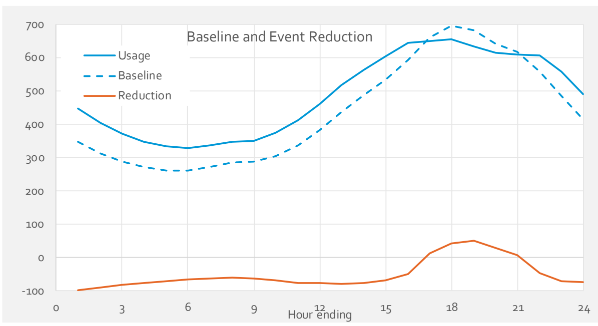
	Settlement Baseline	Load Impact Evaluation
Approach	Within-subjects baseline	Difference-in-difference with Matched controls
Does the approach control for exogenous factors?	No. A pre-post within subjects approach only compares participant load before and during the event. There is no way to identify changes in loads that may not be due to the event.	Yes. Any changes in load not due to the event will be apparent in the loads of the matched control group.
Does the approach minimize statistical noise?	No. The calculation occurs at the account level and individual account loads are inherently noisy from day to day.	Yes. The calculation occurs after aggregating loads across hundreds or thousands of customers. Noise that is apparent at the individual level is thereby averaged out.
Is the approach symmetrical?	No. Customers are compensated for positive event reductions but there is no penalty for reductions which are negative.	Yes. Load increases are treated no differently than load reductions.

Figure 3-6 compares the settlement baseline (left panel) averaged across the average weekday event to the ex post results (right panel) for the average weekday event. The baseline loads shown are calculated at the individual customer level and then summed. As described above the baseline (dotted line in the left panel) is the average of the three highest days among the prior five for each participant. These days are individually selected for each participant and are not necessarily the same days for all participants. The load impact counterfactual (dotted line in the right panel) is the average load for the matched control group, after netting out any minor differences observed between participant and control load on non-event days. Notably, the shape of the load impact counterfactual follows the shape of the observed event day participant load shape very closely. In contrast, the settlement baseline exhibits a very different shape, demonstrating that participant loads on event days are quite different than participant loads on baseline days chosen from the five days preceding each event. Specifically, the baseline exhibits a more pronounced peak than the event day loads. This is to be expected because for each participant, they days with the highest usage (and presumably greater cooling load) have been selected for the baseline days. Average usage for participants on any given day does not exhibit this peaky shape because usage varies from customer to customer. However, the baseline calculated at the individual account level results in a peakier shape which essentially biases the baseline upwards. This issue with individual customer baselines has been well documented.[4,5] This results in a load reduction estimate that is based on a baseline that does not follow the shape of loads on event days: on average, the baseline is far lower than event day loads in non-event hours and far higher in most event hours.

Figure 3-5: Residential ELRP Average Weekday Event Load Impact Compared to Baseline

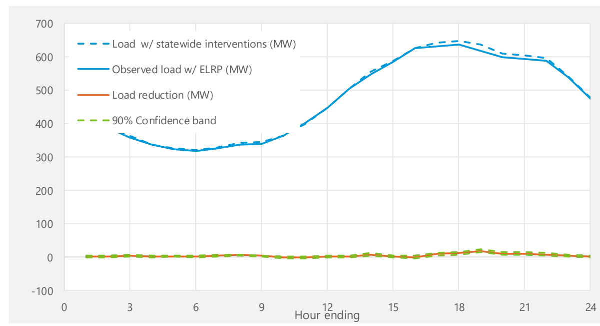
Settlement Baseline - Aggregate (MW)

Avg ELRP load reduction 4PM-9PM	27.02
% ELRP Load reduction 4PM-9PM	4.1%



Load Impact Evaluation - Aggregate (MW)

Avg ELRP load reduction 4PM-9PM	11.91
% ELRP Load reduction 4PM-9PM	1.9%



A common approach for improving gaps between pre and post event baseline and observed load is to apply an adjustment to align the baseline with loads pre and post event. The settlement baseline used did not include an adjustment, but if it had, the resulting adjusted baseline would have more closely matched event day loads in non-event hours. However, because the baseline and event days loads have entirely different shapes (the baseline exhibits a pronounced peak) the result would have been a larger load reduction which would been have further over estimated relative to the load impact evaluation estimate.

3.3.5 Estimated Impact of Statewide Emergency Alert for Residential ELRP Participants

The focus of this report is the evaluation of load impacts attributable to the residential ELRP pilot. However, a supplemental analysis is also provided to estimate the impacts of an exceptional statewide emergency intervention overlapped with the September 6 ELRP event. On that day CAISO triggered an emergency alert that caused cell phones to buzz and issue a warning about grid conditions and a request for all state residents to conserve electricity. Unlike with residential ELRP, there is no group of non-participants that can be used to estimate load impacts because the emergency alert was sent to all cell phones in California. As such a within-subjects time series weather modeling approach was used. This is far less robust than a control group based approach but the ideal approach was not feasible.

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[4] SDG&E Advice Letter 3522-E, Attachment J, Exhibit 2 "Residential CBP Pilot Baseline Accuracy", Figure 8

[5] Statewide Residential Emergency Load Reduction Program Baseline Evaluation, Figure 12, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/emergency-load-reduction-program/statewide_a6_elrp_baseline_evaluation_report_01172023.pdf

Figure 3-6 summarizes the resulting estimate for impacts attributable to the statewide alert, exclusive of ELRP impacts. A clear load response notch is apparent in both the observed participant load (solid blue line) and the counterfactual load (dotted blue line, representing observed control group load adjusted for minor non-event differences with participant loads). This underscores the fact that all customers were exposed to and responded to the emergency alert, including both ELRP participants and non-participants. The dotted grey line is the estimated participant load modeled for the weather conditions on September 6. Essentially, it represents what load would have been expected to be in the absence of any behavioral interventions. The gap between the dotted grey and the doted blue lines shows the estimated 41.80 MW of reductions estimated for ELRP participants due only to the statewide emergency alert. The gap between the dotted blue and the solid blue line shows the estimated 10.53 MW of reductions attributable exclusively to ELRP, net of the statewide intervention.

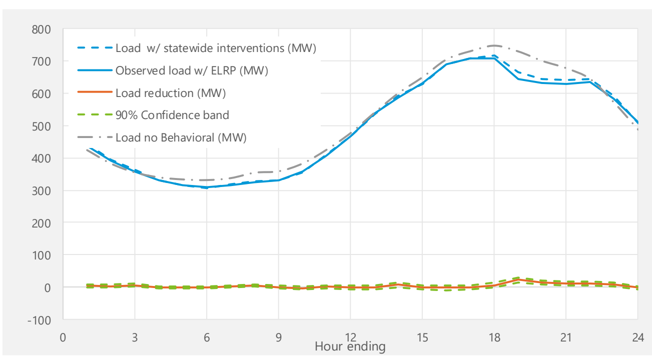
Figure 3-6: Estimated Statewide Alert Impact for Residential ELRP Participants

Table 1: Menu options

Type of results	Aggregate
Category	All
Subcategory	All study segments
Event date	9/6/2022

Table 2: Event day information

ELRP A6 Event start	4:00 PM
ELRP A6 Event end	9:00 PM
Total enrolled accounts	518,955
Avg Emergency Alert Reduction 4PM-9PM	41.80
% Emergency Alert Reduction 4PM-9PM	5.8%
Avg ELRP load reduction 4PM-9PM	10.53
% ELRP Load reduction 4PM-9PM	1.6%



Hour ending	Load no Behavioral (MW)	Load w/ statewide interventions (MW)	Observed load w/ ELRP (MW)	Load reduction (MW)	% Load reduction	Avg temp (F, site weighted)
1	424.03	442.63	438.50	4.14	0.9%	71.1
2	382.16	394.78	391.69	3.09	0.8%	70.4
3	354.78	363.71	357.93	5.78	1.6%	70.3
4	339.74	329.44	330.28	-0.85	-0.3%	70.2
5	333.31	314.31	314.76	-0.45	-0.1%	70.0
6	331.34	307.01	308.54	-1.52	-0.5%	70.4
7	337.48	318.00	314.79	3.21	1.0%	74.5
8	354.24	328.76	324.66	4.10	1.2%	79.5
9	358.62	330.32	330.57	-0.25	-0.1%	83.8
10	382.87	354.18	357.70	-3.52	-1.0%	88.0
11	425.62	408.55	407.96	0.59	0.1%	88.5
12	477.13	468.24	468.86	-0.62	-0.1%	88.0
13	540.52	534.82	537.13	-2.31	-0.4%	88.5
14	600.98	593.71	586.61	7.10	1.2%	89.5
15	649.91	630.64	632.11	-1.47	-0.2%	88.7
16	704.95	689.27	691.34	-2.06	-0.3%	87.3
17	730.49	708.07	708.67	-0.60	-0.1%	83.7
18	747.48	716.02	709.48	6.53	0.9%	80.8
19	729.48	666.09	643.79	22.30	3.3%	78.4
20	700.15	645.12	631.85	13.27	2.1%	77.2
21	677.61	640.93	629.78	11.15	1.7%	75.6
22	643.97	645.73	635.45	10.27	1.6%	75.4
23	570.41	591.15	583.60	7.54	1.3%	74.6
24	487.38	508.00	510.56	-2.56	-0.5%	73.7
	Reference load (MW)	Reference load (MW)	Estimated load w/ DR (MW)	Load reduction (MW)	% Load reduction	Weighted temp (F)
Event Window	717.04	675.24	664.72	10.53	1.6%	79.1

3.4 EX ANTE LOAD IMPACTS

A key objective of the 2022 evaluation is to quantify the relationship between demand reductions, temperature, and hour of day. Ex ante impacts are estimated load reductions as a function of weather conditions, time of day, and forecasted changes in enrollment. By design, they reflect planning conditions defined by normal (1-in-2) and extreme (1-in-10) peak demand weather conditions. The historical load patterns and performance during actual events are used as the reductions for a standardized set of weather conditions.

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

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

3.4.1 Relationship of Customer Loads and Percent Reductions to Weather

Figure 3-7 summarizes the relationship between weather and customer load for residential ELRP customers. Only non-event days are included. The panel to the left shows the relationship between daily maximum temperatures and daily peak loads. The panel to the right shows average hourly loads for current participants for different temperature bins, defined by the daily maximum temperature. The hottest temperature day in the right panel is the highest load curve. In 2022 we see the expected pattern that energy demand and discretionary load increases with hotter weather.

Figure 3-7: Weather Sensitivity of Residential ELRP Program Participant Loads

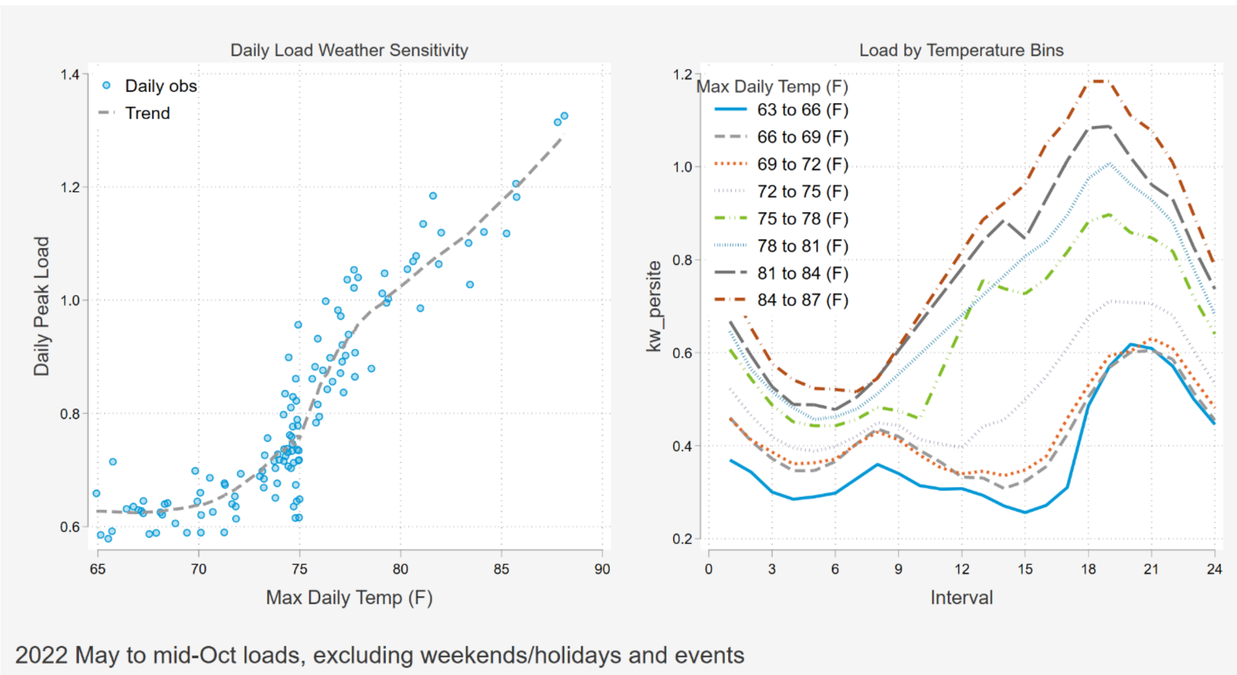


Figure 3-8 shows the relationship between aggregate residential ELRP loads and SDG&E daily peak loads. Residential ELRP loads are highly correlated with system load daily peaks during the 4 to 9 pm resource adequacy window. Because residential loads are a major driver of SDG&E peaks, if managed, they can reduce the need to build additional infrastructure to accommodate additional peak load. Because more discretionary load is in use during peaking conditions, reductions from ELRP participants can be larger precisely when resources are needed most.

Figure 3-8: Residential ELRP Customer Loads During System Load Daily Peaks

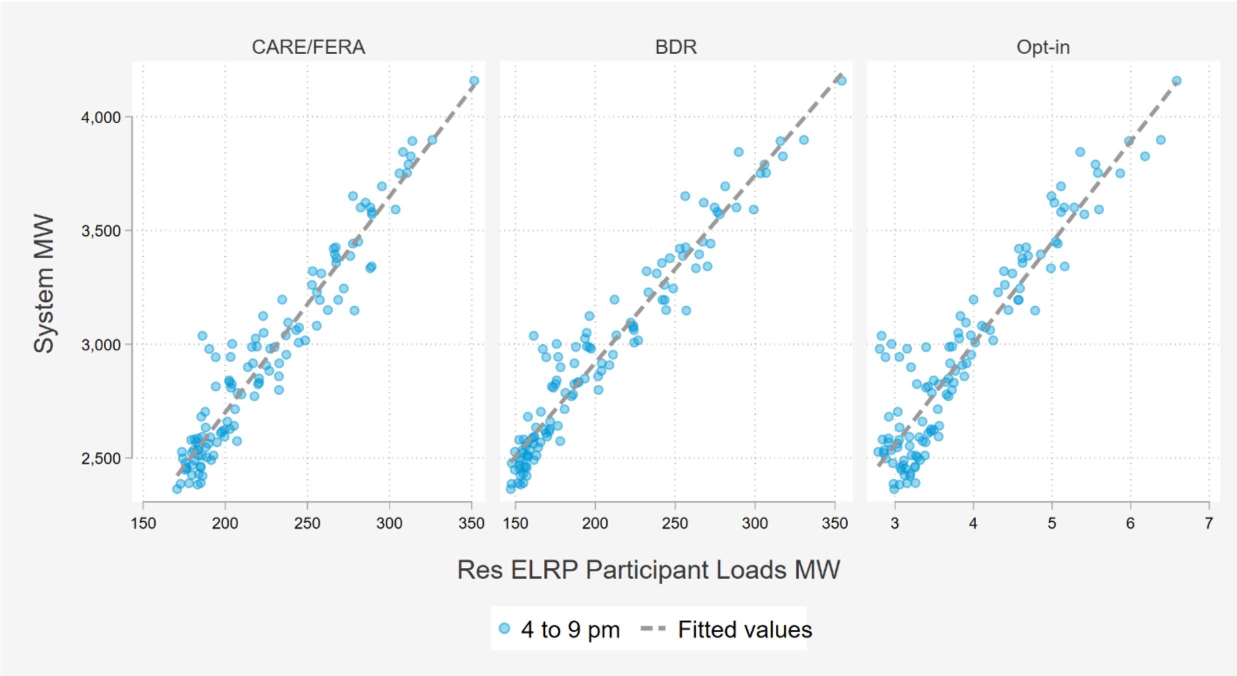
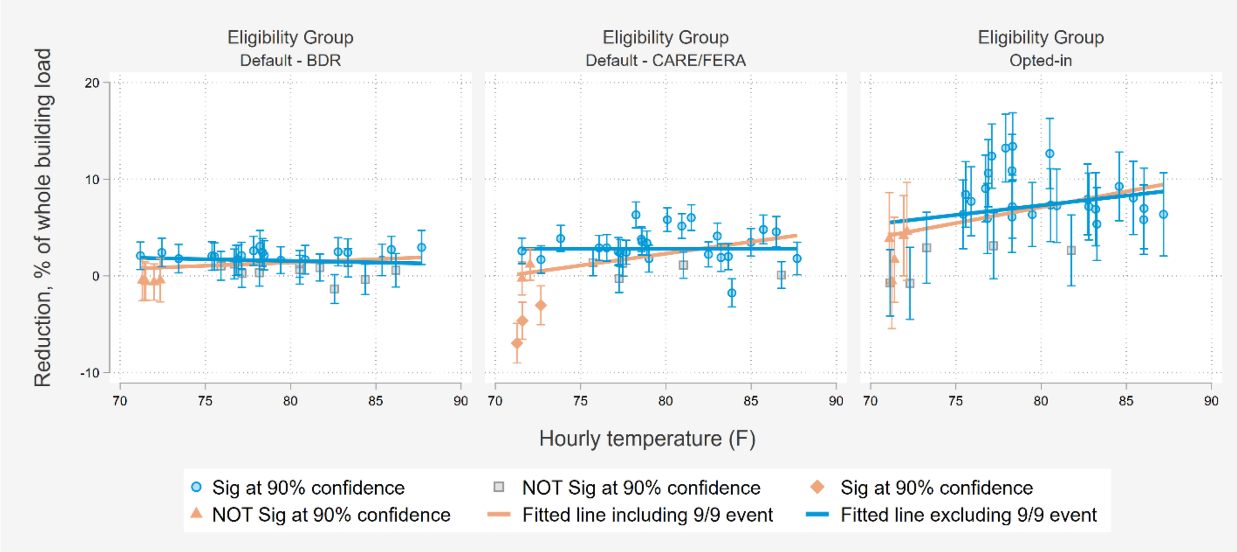


Figure 3-9 shows hourly event percent reductions for these events as a function of hourly temperatures. The panels show percent reductions for each eligibility group. Note that while most reductions are positive in magnitude, or near zero and not statistically significant, a handful are negative and significant. Most of these negative reductions occurred on the September 9 event which exhibited unusual weather patterns including rapidly dropping temperatures after more than a week of elevated temperatures. The evaluation team observed that including September 9 reductions in the ex ante impact model, with that event's low temperatures and negative or very small reductions, made the ex ante impact model extremely weather sensitive. This extreme weather sensitivity combined with hot ex ante conditions created ex ante reductions that were implausibly large. Thus, September 9 was excluded as an input into the ex ante impact model. This effect is shown in Figure 3-9: including September 9 event reductions makes the slope of the fitted line (colored orange) significantly steeper than the fitted line excluding September 9 reductions (colored blue).

Opted-in customers show a strong positive trend as warmer temperatures result in larger percent reductions. Defaulted CARE / FERA customers showed a positive trend before the September 9 event reductions were excluded, but show a flat trend once September 9 is excluded due to that event's anomalous negative reductions and weather. For defaulted BDR customers percent reductions were relatively flat as temperatures increased.

Figure 3-9: 2022 Residential ELRP Hourly Reductions and Temperatures[6]



3.4.2 Ex Ante Enrollment Forecast

To derive the aggregate forecast and reference and loads percent impacts per customer and are scaled to the site population expected to be enrolled in each planning year. A separately enrollment forecast was developed for each eligibility group and each incorporates:

- Expected new site enrollments per year
- Expected site attrition
- Expected site growth

Table 3-8 summarizes population, attrition, and enrollment growth assumptions used to derive the enrollment forecasts for PY 2022 using the enrollment model described above. Note that PY 2022 site enrollments are the same as the pre-event August enrollments used for the PY 2022 ex post analysis. Attrition, which ranges between 0 and 1%, is applied annually and is based on the portion of participants retained as of September 22, 2022 and reflect drops in enrollment after the event season. Growth rates are specific to each eligibility group. SDG&E does not plan to default enroll new BDR customers in the future so the growth rate is assumed to be zero. The CARE/FERA population is assumed to grow by 1% annually (which roughly reflects overall population growth). SDG&E plans to continue default enrollment of new CARE / FERA customers so the enrolled population is also assumed to grow by 1% annually. A different approach is used for the opted-in participants since they self-enroll

[6] Participant weighted temperature in each event hour. Hourly event temperatures shown are largely lower than daily maximum temperatures since event hours occur between 4 pm and 9 pm when temperatures are cooler.

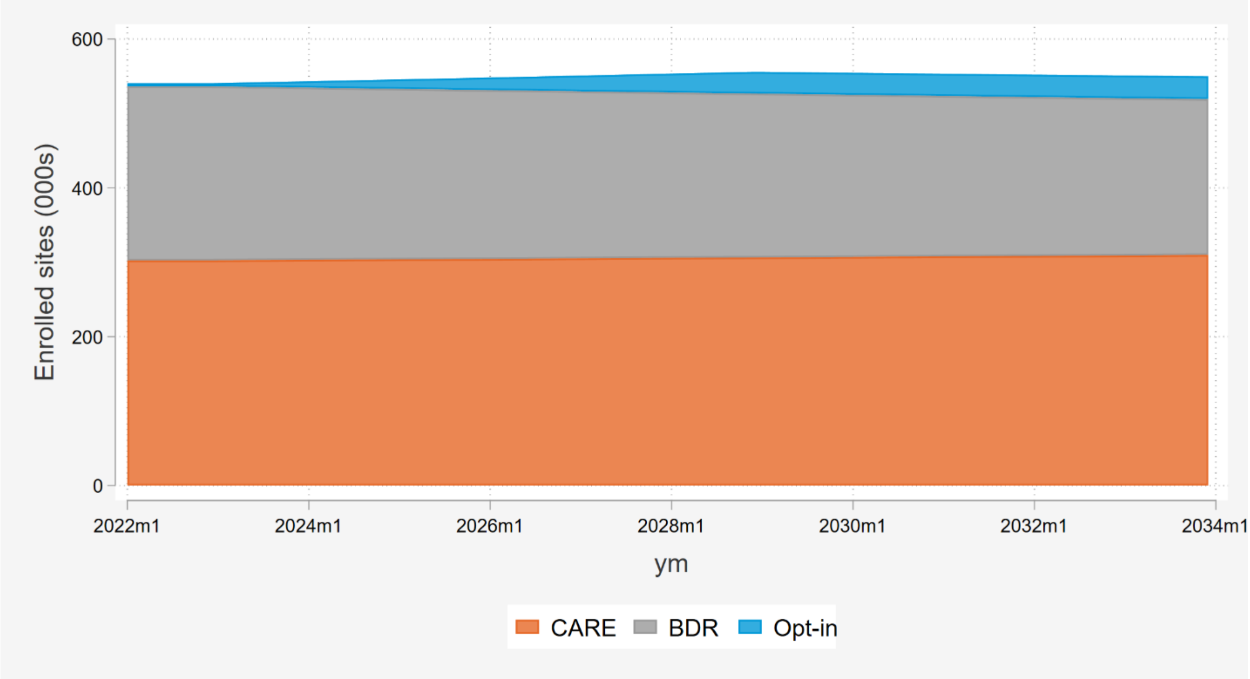
in ELRP. In PY 2022 about 1% of the eligible population enrolled. As SDG&E continues to market ELRP to eligible customers, this rate of enrollment is assumed to continue annually until 5% of the total eligible population is enrolled. This is roughly the portion of the population that enrolled in SDG&E's Peak Time Rebate program, a similar opt-in load reduction program also based on individual settlement baselines.

Table 3-8: Residential ELRP Program Enrollment Forecast Assumptions

Eligibility Group	NEM	Enrolled population (Aug 2022)	Attrition (drop in 9/22, e.g. after events)	Growth
BDR (not on CARE)	Yes	8,813	0.4%	0%
BDR (not on CARE)	No	225,235	1%	
CARE (includes linked to BDR)	Yes	4,077	0.8%	1% (e.g. population growth)
CARE (includes linked to BDR)	No	298,439	0.5%	
Self-enroll (Opt-in eligible)	Yes	151	0.8%	1% of eligible population enrolled in the first year. Assume additional 1% enrolls each year until 5% total is enrolled
Self-enroll (Opt-in eligible)	No	3,921	0%	
TOTAL		540,636		

Figure 3-10 shows the resulting enrollment forecast by Residential ELRP eligibility group. Reflecting the assumptions above, the defaulted CARE / FERA population is suspected to grow slightly and the defaulted BDR population is expected to wane slightly but both remain relatively steady over time and are expected to continue to represent the majority of the enrolled population. The opted-in population is expected to grow meaningfully but still remain a relatively small share of the population. For the purposes of monthly ex ante load estimates changes in population are spread evenly from month to month.

Figure 3-10: Residential ELRP Enrollment Forecast



3.4.3 Ex Ante Load Impacts

Table 3-9 summarizes the 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 on August monthly peaking conditions for 1-in-2 and 1-in-10 weather conditions. They align with the planning conditions used for resource adequacy attribution. They incorporate an enrollment forecast for sites described above. Load reductions are estimated for each eligibility group so reductions per enrolled site increase slightly over time as the opted-in population, which also delivers higher percent reductions, comprises a slightly larger share of the population.

Table 3-9: Portfolio Impacts for August Monthly Peak Day

Year	Sites	Avg. reference load (kW)	CAISO		SDG&E	
			1-in-2	1-in-10	1-in-2	1-in-10
2022	540,636	1.21	12.64	13.22	12.86	13.33
2023	542,245	1.21	12.81	13.45	13.07	13.60
2024	544,702	1.21	13.08	13.81	13.38	14.01
2025	547,226	1.21	13.34	14.17	13.70	14.42
2026	549,815	1.21	13.61	14.53	14.02	14.83
2027	552,470	1.21	13.88	14.90	14.34	15.26
2028	555,070	1.20	14.15	15.26	14.66	15.67
2029	555,099	1.20	14.24	15.39	14.77	15.82
2030	553,868	1.20	14.24	15.41	14.78	15.85
2031	552,657	1.20	14.24	15.42	14.79	15.88

Year	Sites	Avg. reference load (kW)	CAISO		SDG&E	
			1-in-2	1-in-10	1-in-2	1-in-10
2032	551,473	1.20	14.24	15.44	14.80	15.90
2033	550,315	1.20	14.24	15.46	14.81	15.93

3.4.4 Comparison of Ex Post And Ex Ante Load Impacts

Table 3-10 compares the demand reductions from 2022 events to the PY 2022 reductions expected for the 1-in-2 weather conditions used for planning. Results are shown for the 4 to 9 pm resource adequacy window and compared to the average PY 2022 weekday event.

In 2022, residential ELRP customers delivered 11.91 MW during the during the 4 to 9 pm event window which also aligns with the 4 to 9 pm resource adequacy window. The SDG&E weather ex ante prediction for 2022 is slightly higher than the ex post reduction because the average ex ante temperature during the 4pm to 9pm event window is about 4 degrees higher than the temperature observed during the average PY 2022 weekday event. The CAISO ex ante prediction is closer to the ex post reduction because the temperatures are closer. Percent reductions for the 4 to 9 pm event period were 1.9%. Ex ante predictions show a 2.0% to 2.1% reduction over the 4 to 9 pm window. Further, the ex post estimate shows results for the average number of sites that were enrolled and did not experience an outage during events (about 525,000). The ex ante estimate used the full population of sites enrolled in PY 2022 (about 540,000).

Table 3-10: Residential ELRP Comparison of Ex Post and Ex Ante Load Impacts for 2022

Result Type	Day Type and Period	Sites	Load without DR (MW)	Load Reduction (MW)	% Reduction	Avg Event Temp (F)	Daily Max Temp (F)
Ex Post Avg. Weekday	Resource Adequacy Period (4 to 9pm)	525,382	628.16	11.91	1.9%	78.4	87.8
Ex ante SDG&E	1-in-2 Weather August Peak (4 to 9pm)	540,636	636.77	12.86	2.0%	82.6	88.5
Ex ante CAISO	1-in-2 Weather August Peak (4 to 9pm)	540,636	600.62	12.64	2.1%	80.6	86.1

3.4.5 Ex Ante Load Impact Slice-of-Day Tables

Table 3-11 and Table 3-12 show the 2022 ex ante aggregate hourly impacts for each month under CAISO and SDG&E monthly peaking conditions, respectively. The tables are designed to enable the

CPUC's Slice-of-Day Resource Adequacy requirements. The estimated reductions are greatest in August and September as there is the most amount of cooling load available to be curtailed. Response to an event begins early in the day around 11am and peaks in the late afternoon when temperatures are typically the hottest.

Table 3-11: Slice of Day Table for CAISO 1-in-2 Weather Year Monthly Peak Day (Aggregate Impacts (MW))

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	5.09	5.09	5.09	6.42	5.96	7.54	8.80	9.20	9.52	8.23	6.35	5.09
13	5.04	5.04	5.04	6.68	6.13	8.17	9.66	10.29	10.57	9.07	6.76	5.04
14	5.15	5.15	5.15	7.08	6.46	8.90	10.57	11.23	11.62	10.29	7.51	5.15
15	5.47	5.47	5.47	7.61	6.95	9.57	11.59	12.10	12.49	11.17	8.16	5.47
16	5.94	5.94	5.94	8.20	7.58	10.28	12.54	12.99	13.34	12.21	9.01	5.94
17	6.45	6.45	6.45	8.60	8.01	10.45	12.61	13.15	13.25	12.08	9.48	6.45
18	7.08	7.08	7.08	9.21	8.53	10.77	12.75	13.08	13.28	12.06	10.08	7.08
19	7.38	7.38	7.38	9.24	8.73	10.81	12.51	12.90	13.00	11.74	10.50	7.38
20	7.40	7.40	7.40	9.13	8.56	10.53	11.84	12.15	12.52	11.51	10.19	7.40
21	7.41	7.41	7.41	9.13	8.41	10.37	11.40	11.93	12.05	11.28	10.00	7.41
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 3-12: Slice of Day Table for SDG&E 1-in-2 Weather Year Monthly Peak Day (Aggregate Impacts (MW))

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	5.09	5.09	5.09	6.90	6.78	7.51	9.03	9.34	9.46	7.90	6.38	5.09
13	5.04	5.04	5.04	7.45	7.20	8.16	10.20	10.37	10.83	8.64	6.78	5.04
14	5.15	5.15	5.15	8.00	7.69	8.85	11.21	11.42	11.83	9.39	7.43	5.15
15	5.47	5.47	5.45	8.52	8.20	9.51	12.29	12.79	12.74	10.18	8.31	5.47
16	5.94	5.94	5.92	9.27	8.69	10.24	13.74	13.73	13.81	11.13	9.34	5.94
17	6.45	6.45	6.45	9.52	8.97	10.26	13.72	13.52	13.60	11.29	9.86	6.45
18	7.08	7.08	7.08	9.89	9.23	10.54	13.75	13.33	13.28	11.16	10.47	7.08
19	7.38	7.38	7.38	9.78	9.30	10.36	13.22	12.98	13.00	11.16	10.82	7.38
20	7.40	7.40	7.40	9.97	9.37	10.07	12.46	12.34	12.50	11.23	10.44	7.40
21	7.41	7.41	7.41	9.95	9.51	10.06	11.95	12.14	12.45	11.13	10.08	7.41
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Demand reductions are positive (Blue)												
Load increases are negative (Orange)												

4 CONCLUSIONS AND RECOMMENDATIONS

The Residential ELRP program delivered statistically significant demand reduction and energy savings, but there is room for improvement. The recommendations below may not be currently funded, and costs need to be considered alongside other research and program priorities.

4.1 RESIDENTIAL ELRP RECOMMENDATIONS

- **Do not default any additional BDR sites on TOU and consider converting BDR sites on TOU rates to opt-in**. While this group represents about third of reductions, the smaller percent reductions are also less likely to be distinguishable from noise using the baseline settlement approaches used to compensate participants, and therefore more likely to result in overpayment. To still retain engaged sites opt-in messaging could be sent to BDR sites on TOU rates requiring them to opt-in to stay enrolled.

- **Possibly tailor BDR outreach message to TOU vs non-TOU customers.** Defaulted BDR sites that are not on TOU rates still retain a load shape with a peak concentrated from 4 to 6pm and their load reductions are concentrated during these hours, indicating that there may be more discretionary load that can be shed for these customers during these hours.