DRAFT REPORT

CALMAC ID: SDG0351

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

Prepared for SD&GE
By Demand Side Analytics, LLC
April 1, 2023

ACKNOWLEDGEMENTS

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ABSTRACT

This study quantifies the demand impacts of the Non-Residential Emergency Load Reduction Program 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 pilot was rolled out in 2021 upon direction by the Commission to expand the state's portfolio of emergency load reduction resources beyond those available in CAISO capacity markets and utility specific emergency resources such as Critical Peak Pricing. Events are triggered by the CAISO in response to extreme grid stress, and event reductions are settled via a $2/kWh payment, determined using baseline settlement rules. Ten ELRP events were called in PY 2022, with different subgroups being dispatched for specific events. The average PY 2022 weekday 4pm to 9pm event produced 37.21 MW of reduction across all ELRP subgroups.

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1 EXECUTIVE SUMMARY

The Emergency Load Reduction Program (ELRP) pilot is a behavioral demand response program with direct settlements and performance payments to participant sites. The pilot was rolled out in 2021 upon direction by the Commission to expand the state's portfolio of emergency load reduction resources beyond those available in CAISO capacity markets and utility specific emergency resources such as Critical Peak Pricing. ELRP. As its name implies, ELRP is an out of market emergency resource. It includes multiple subgroups (Groups A.1, A.2, A.3, A.4, A.5 for customers and aggregators not participating in Demand Response, and Groups B.1 and B.2 for demand response resources) 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. There is also a residential subgroup (A.6) which has been evaluated separately and is not the focus of this report. All ELRP groups remunerate participant site 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.

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 4 to 9pm weekday ELRP event for each subgroup in which SDG&E customers are enrolled. There were no enrollments in groups A.4 or B.1 in PY 2022.

Table 1-1: Summary of Average Weekday 4 to 9 pm 2022 Ex Post Demand Reductions

ELRP Group	Sites	Load without DR (MW)	Load reduction (MW)	% Reduction
A.1: Non-Res Customers	412	195.41	36.45	18.7%
A.2: Non-Res Aggregators	17	4.60	-0.12	-2.7%
A.3: Rule 21 Exporting DERs	1	0.00	0.00	-299.1%*
A.5: Vehicle-Grid-Integration (VGI) Aggregators	2	0.02	0.01	60.5%
B.2: IOU Capacity Bidding (CBP) PDRs	117	16.24	0.88	5.4%

*Can be disregarded as essentially 0% given the negligible load, change in load and single enrolled account

Table 1-2 summarizes forecasted site enrollments by subgroup. Enrollments are expected to flatten and drop slowly after 2029 and to be concentrated in subgroups A.1 (non-residential customers not in DR programs) and A.4 (Virtual Power Plants, e.g. battery storage aggregation), which is expected to begin enrollments in PY 2023.

Table 1-2: Summary of Ex ante Site Enrollments

Year	ELRP						Total
	A1	A2	A3	A4	A5	B2	
2022	474[1]	17	1	0	2	121	615
2023	484	17	1	1,154	2	123	1,782
2024	492	18	1	3,206	2	125	3,843
2025	497	18	1	4,945	2	126	5,590
2026	503	18	1	5,975	2	128	6,627
2027	509	18	1	6,731	2	130	7,390
2028	514	18	1	7,536	2	131	8,202
2029	514	18	1	7,536	2	131	8,202
2030	514	18	1	7,536	2	131	8,202
2031	514	18	1	7,536	2	131	8,202
2032	514	18	1	7,536	2	131	8,202
2033	514	18	1	7,536	2	131	8,202

Table 1-3 summarizes ELRP dispatchable ex ante reductions under August monthly peaking conditions for an SDG&E and CAISO 1-in-2 weather year. ELRP load reductions are primarily the result of dispatchable generation and weather responsiveness of the load reduction could not be established in PY 2022. As such load reductions are assumed to be the same for all weather specifications. The results in the table below reflect the reduction capability from 4pm to 9pm, which aligns with resource adequacy requirements. The ex ante load reduction prediction for PY 2022 is developed using a top down enrollment forecast model derived from the dispatchable generation capacity currently interconnected and the expected growth of dispatchable generation capacity. The forecast for PY 2022 reflects the average load reduction across all events (not just weekday 4-9pm) and therefore deviates from the ex post reductions for the average 4 to 9 pm weekday event.

[1] Includes 54 participants that enrolled after the last PY 2022 event

Table 1-3: Summary of Ex ante Dispatchable Demand Reductions, SDG&E & CAISO 1-in-2 Weather

Year	ELRP (MW)						Total
	A1	A2	A3	A4	A5	B2	
2022	28.01	0.04	0.01	0.00	0.02	0.72	28.80
2023	28.90	0.04	0.01	2.26	0.04	0.76	32.00
2024	29.82	0.04	0.01	6.27	0.04	0.79	36.97
2025	30.67	0.04	0.01	9.70	0.04	0.80	41.27
2026	31.68	0.05	0.01	11.76	0.04	0.82	44.35
2027	32.69	0.05	0.01	13.27	0.04	0.84	46.89
2028	33.53	0.05	0.01	14.87	0.04	0.86	49.36
2029	33.53	0.05	0.01	14.87	0.04	0.86	49.36
2030	33.53	0.05	0.01	14.87	0.04	0.86	49.36
2031	33.53	0.05	0.01	14.87	0.04	0.86	49.36
2032	33.53	0.05	0.01	14.87	0.04	0.86	49.36
2033	33.53	0.05	0.01	14.87	0.04	0.86	49.36

2 INTRODUCTION

The Emergency Load Reduction Program (ELRP) pilot is a behavioral demand response program with direct settlements and performance payments to participant sites. The pilot was rolled out in 2021 upon direction by the Commission to expand the state's portfolio of emergency load reduction resources beyond those available in CAISO capacity markets and utility specific emergency resources such as Critical Peak Pricing. As its name implies, ELRP is an out of market emergency resource. It includes multiple subgroups (Groups A.1, A.2, A.3, A.4, A.5 for customers and aggregators not participating in Demand Response, and Groups B.1 and B.2 for demand response providers) 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. There is also a residential subgroup (A.6) which has been evaluated separately and is not the focus of this report. All ELRP groups remunerate participant site 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.

2.1 PROGRAM BACKGROUND

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

- deployment triggers: the ELRP is dispatched via emergency triggers as opposed to economic triggers
- payment rules: ELRP has no penalties or capacity payments
- baseline settlement rules: top 10 of 10 with asymmetric adjustment 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 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

	Eligibility Requirements
A.1	Bundled and unbundled non-residential customers of an IOU who meet the following criteria are eligible to enroll and participate in ELRP:

<table>
<tr><th colspan="2">Eligibility Requirements</th></tr>
<tr><td></td><td>Customer's service account must be able to reduce load by a minimum of 50 kW during an ELRP event
Customer is not simultaneously enrolled in another supply-side DR program offered by an IOU, third-party demand response provider (DRP), or community choice aggregator (CCA), with the exception that dual enrollment in SDG&E's Base Interruptible Program (BIP). If an eligible BIP customer is participating with a BIP aggregator, then the BIP customer must participate under Sub-Group A.2.</td></tr>
<tr><td>A.2</td><td>Third-party non-residential aggregators including BIP aggregators are eligible to participate in ELRP.

Non-BIP aggregators with aggregated bundled or unbundled non-residential customer resources meeting the following criteria are eligible to participate in ELRP:
Customer's service account is classified as non-residential; and
The aggregated resource is not simultaneously enrolled in a supply-side DR program offered by an IOU, third-party DRP, or CCA, and
The aggregated resource capacity meets or exceeds Minimum the Aggregation Size Threshold at 500 kW</td></tr>
<tr><td>A.3</td><td>Bundled and unbundled non-residential customers of an IOU who meet the following criteria are eligible to enroll and participate in ELRP:
Customer is not simultaneously enrolled in any market-integrated DR program offered by an IOU, third-party DRP, or CCA, and
Customer possesses a behind-the-meter (BTM) Rule 21-interconnected device (including Prohibited Resources) with an existing Rule 21 export permit, and
Customer's BTM Rule 21 interconnected device meets the Minimum Export Threshold of 25kW specified further below for at least one hour in compliance with Rule 21 and other applicable regulations and permits during an ELRP event.</td></tr>
<tr><td>A.4</td><td>An aggregator managing a BTM virtual power plant (VPP) aggregation consisting of storage paired with net energy metering (NEM) solar or stand-alone storage deployed with residential (bundled or unbundled) or non-residential (bundled or unbundled) customers, whose VPP meet the following criteria, is eligible participate in ELRP:</td></tr>
</table>

	Eligibility Requirements
	▪ The VPP or any customer site within the aggregation is not simultaneously enrolled in a market-integrated DR program offered by an IOU, third-party DRP, or CCA, and ▪ All sites within the VPP aggregation are located within the distribution service area of a single IOU, and ▪ The aggregated BTM storage capacity of the VPP meets the Minimum VPP Size Threshold 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.
A.5	An 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 an IOU, third-party DRP, or CCA, and ▪ All sites within the VGI aggregation are located within the distribution service area of a single IOU, and ▪ The VGI aggregation can contribute Incremental Load Reduction (ILR) of at least 25 kW for a minimum of one hour during an ELRP event. ▪ Subject to Rule 21 interconnection requirements, any direct current (DC) V2G electric vehicle supply equipment (EVSE) that has UL 1741[2] certification but not UL 1741 SA certification, any subsequent UL 1741 supplement certification required in Rule 21, or Smart Inverter Working Group-recommended smart inverter functions may interconnect initially, but only for the purpose of participating in the ELRP.
B.1	A third Party DRP with a market-integrated Proxy Demand Resource (PDR) is eligible to participate in the ELRP.

[2] Direct Current (DC) V2G EVSE that have UL 1741 certification, but not UL 1741 SA, may interconnect initially for the purposes of participating in the ELRP, subject to remaining Rule 21 interconnection requirements. SDG&E reserves the right to terminate this exception after the 2024 ELRP season.

	Eligibility Requirements
B.2	Third-party aggregators (Aggregators) or self-aggregated customers (Participant sites) enrolled and participating in SDG&E's Capacity Bidding Program are eligible to participate in the ELRP.

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 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 subgroup (Group A and Group B subgroups) 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?

2.3 OVERVIEW OF METHODS

The primary challenge of impact evaluation is the need to accurately detect changes in energy consumption while systematically eliminating plausible alternative explanations for those changes, including random chance. Did the introduction of the ELRP program 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 individual customer regressions with synthetic controls including one or more control site matched to each participant site. Key modeling design components are as follows:

- **Matched control tournament:** In order 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), 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[3].

- **Out of sample regression model tournament to select most accurate model for each participant site:** The data was structured with participant site loads and control site loads side by side. Additional synthetic controls considered in the tournament included 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. Site specific models selected using out of sample testing which assigned. 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)[4]. Site specific load impacts were estimated with using the winning model for each site.

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

- Inclusion of an industry profile constructed of loads for other similar large commercial and industrial customers[5]

[3] Bins were constructed using average usage on event-like proxy days. For solar customers bins were constructed based on system size
[4] While RRMSE is typically a more robust fit metric due to normalization, it was not used here due to the preponderance of sites with dispatchable generation and therefore negative and near zero loads which tend to yield unstable normalization due to use of these small loads in the denominator
[5] With the same 3 to 4 digit NAICS codes or with customer names indicating similar activities, e.g. university or college for UCSD, chemical manufacture ring for pharmaceuticals manufacturing, etc. An average industry profile

- Inclusion of local solar irradiance data[6]
- Number of control sites[7]
- Lags of load data[8]

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

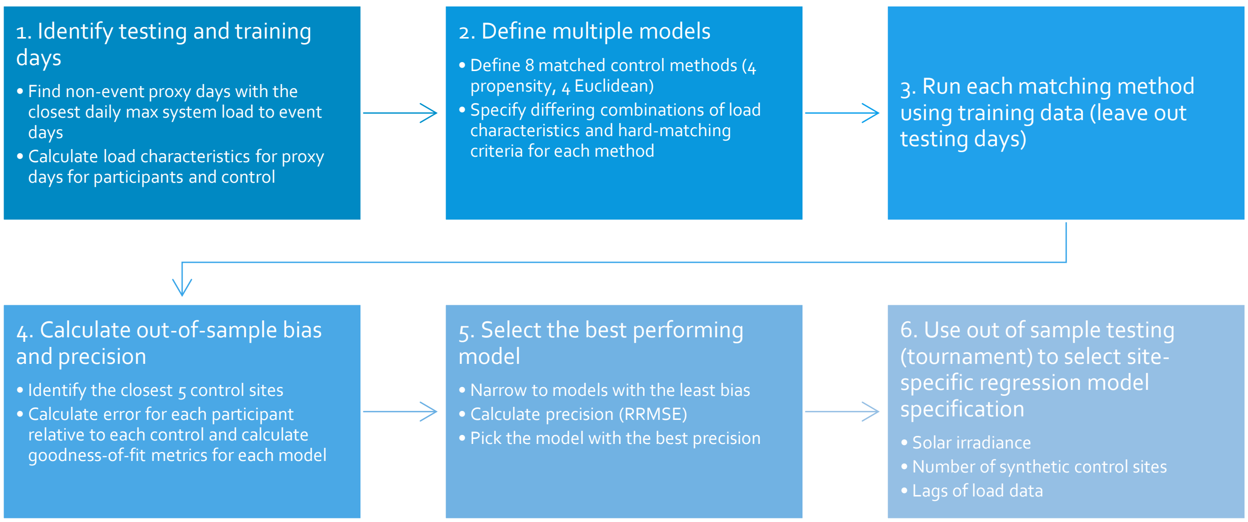

Figure 2-2 shows the different model parameters that were included in the site specific model tournament and the number of sites for which each parameter was included in the winning model. The wide spread across parameters indicates that it was important to allow for individually tailored models to be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

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for a given participant was the average of loads for customers with similar activities, scaled from 0 to 100 to avoid bias due to differences in load magnitudes.

[6] Specific to the weather station nearest to the participant

[7] Selected using the out of sample match selection process.

[8] Intended 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

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

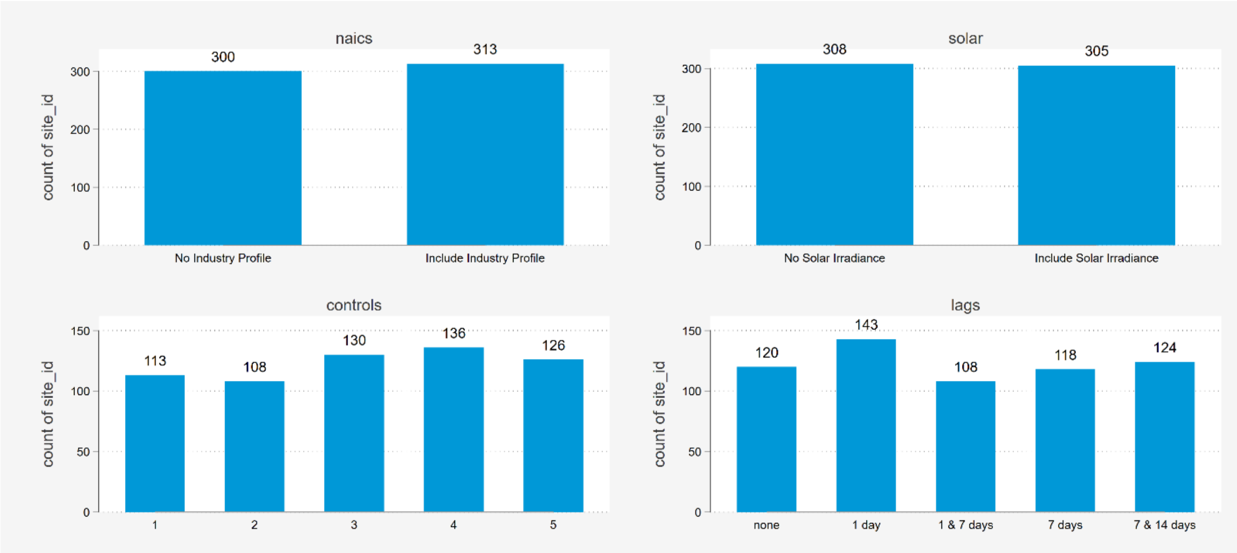


Table 2-3 summarizes the data sources, segmentation, and estimation methods used for each program. The segmentation was defined in advance of the analysis and is of particular importance because the evaluation used a bottom up approach to estimate impacts and to ensure that aggregate impacts across segments 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 2-3: Evaluation Methods

Evaluation Element	Non-Residential ELRP (A.1, A.2, A.3, A.4, A.5, B.2)
Data sources / samples	▪ All event season data for the past program year for ✓ All 561 Non-Residential ELRP participant sites ✓ a control pool of 32k small and large commercial non participants
Segmentation	▪ ELRP Subgroup
Estimation method: Ex-post	▪ Site specific regression models with synthetic controls

Evaluation Element	Non-Residential ELRP (A.1, A.2, A.3, A.4, A.5, B.2)
Estimation method: Ex-ante	▪ Top down enrollment model based on projections for interconnected capacity and feasible enrollment levels. ▪ Load reductions are assumed to be a function of dispatchable generation capacity not weather sensitive load curtailment and therefore 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. Participant sites and non-participants were also exposed to statewide flex and emergency alert interventions so ELRP reductions are incremental to those impacts.

3.1 EVENT CHARACTERISTICS

Event impacts were assessed by site (premise and service point combination). While the modeling was performed individually for each site, results are reported by ELRP subgroup, summarized in Table 3-1. 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 enrolled during the PY 2022 event season, for which the first event was called on August 17 and the last on September 9. The number of sites in the ex post analysis is slightly smaller than the total number of sites due to the removal of sites with outages on event days and sites for which an adequate matched control could not be found.

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

ELRP Group	Total Sites	Sites in analysis
A.1	420	412
A.2	17	17
A.3	1	1
A.5	2	2
B.2	121	117
Total	**561**	**549**

Table 3-2 shows the 10 PY 2022 ELRP event days and the SDG&E system peak load on each day. While event dispatch dates and hours were the same for most subgroups and events there were two minor differences: not all subgroups were called for the two August events and B.2 event hours were shorter than the other groups for the September 1 event. Of the ten events called, seven consecutive events were called beginning on the Saturday before Labor Day and ending on the Friday after Labor Day. Seven events occurred on weekdays and three occurred on weekends or holidays. The SDG&E system peaked on September 7.

[9] Excludes 54 A.1 participants that enrolled after the last PY 2022 event

Table 3-2: ELRP Events in 2022

Event date	Day of week	Event window	A.1	A.2	A.3	A.5	B.2	Max SDG&E system load (MW)
8/17/2022	Wednesday	4 to 9 pm	✗	✓	✗	✗	✗	3,738
8/31/2022	Wednesday	5 to 8 pm	✓	✓	✓	✓	✗	4,158
9/1/2022	Thursday	6 to 8 pm*	✓	✓	✓	✓	✓	4,483
9/3/2022	Saturday	6 to 8 pm	✓	✓	✓	✓	✓	4,406
9/4/2022	Sunday	5 to 8 pm	✓	✓	✓	✓	✓	4,168
9/5/2022	Monday	5 to 9 pm	✓	✓	✓	✓	✓	4,201
9/6/2022	Tuesday	4 to 9 pm	✓	✓	✓	✓	✓	4,322
9/7/2022	Wednesday	4 to 9 pm	✓	✓	✓	✓	✓	4,633
9/8/2022	Thursday	4 to 9 pm	✓	✓	✓	✓	✓	4,291
9/9/2022	Friday	4 to 7 pm	✓	✓	✓	✓	✓	3,898

*Group B.2 only called from 6 to 7 pm

3.2 DATA SOURCES AND ANALYSIS METHOD

Table 3-3 summarizes the five data sources used to conduct the Non-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: Non-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: 561 ELRP accounts ▪ Control: Sample of 32k non-residential sites not in other DR programs ▪ NEM status, climate zones used in matched control selection ▪ NAICS codes for development of industry profiles
SDG&E hourly system loads	▪ Summer 2022

[10] Excludes 54 A.1 participants that enrolled after the last PY 2022 event

Source	Comments
	▪ 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 site specific regression models with synthetic controls. An out of sample tournament was used to select a matching model for each subgroup. Matches were one of multiple synthetic controls used in the regression models. The winning distance matching approach selected one matched control site for each of the 561 ELRP participant sites among a control candidate pool of roughly 32,000 sampled non-residential sites who were not enrolled in other DR programs which might influence energy use and which render a customer ineligible for ELRP[11].

Once the matches were selected for each participating site, an out of sample tournament was used to select site specific regression models. Non-typical, or very large customers tend to be more difficult to match because there are fewer other customers with similar load patterns. As such, many site specific synthetic control regression models were considered. Model parameters included industry profiles, solar irradiance, matched controls, 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 not participating in DR programs and is currently by far the largest ELRP subgroup with over 400 participating sites. There were 9 events called for subgroup A.1 in PY 2022, for a variety of durations and start times. Table 3-4 summarizes the load reductions for ELRP A.1 sites for the 9 events and for the average 4 pm to 9 pm weekday event. The average weekday event reductions were significant with an average aggregate reduction of 36.45 MW. 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 also summarizes the number of sites enrolled and analyzed for each event day. A participant site needed to have data available both for the event and for the relevant proxy day and a matched control needed to have been found to be included in the estimate for a given event.

Aggregate reductions for significant events range from 53.34 MW (September 5, Labor Day) to 15.26 MW (September 1). No clear correlation between weather conditions, event window, and load

[11] Though CBP participants are eligible for subgroup B.2, there were too few CBP sites that were not participating in ELRP so this criteria was not used for matching.

reductions is evident. For example, load reductions varied substantially for the August 31, September 1, and September 5 events, despite having similar average event temperatures and dispatch windows. Further, while the lowest load occurs on the coolest day (September 9, 3.78 MW) the highest load reduction occurs on the day with the second lower average temperature (September 5, 53.34 MW). For this reason ex post reductions were not used to develop a weather based load reduction model for the ex ante forecast.

Table 3-4: ELRP Group A.1 Event Reductions

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post) Aggregate (MW)	% Reduction	Average Site (kW)	Significant (90% CI)	Significant (95% CI)	Reductions (Baseline) Aggregate (MW)	Average Site (kW)
8/31/2022	5 to 8 pm	79.5	390	4.55	3.6%	11.67	No	No	9.50	24.36
9/1/2022	6 to 8 pm	77.9	393	15.26	7.7%	38.83	Yes	Yes	36.37	92.55
9/3/2022	6 to 8 pm	86.2	395	29.55	17.7%	74.82	Yes	Yes	63.87	161.70
9/4/2022	5 to 8 pm	80.7	395	36.23	21.7%	91.71	Yes	Yes	69.77	176.63
9/5/2022	5 to 9 pm	77.0	395	53.34	29.9%	135.03	Yes	Yes	71.67	181.44
9/6/2022	4 to 9 pm	78.8	404	42.45	21.8%	105.07	Yes	Yes	60.64	150.10
9/7/2022	4 to 9 pm	80.1	414	31.32	15.9%	75.64	Yes	Yes	50.62	122.27
9/8/2022	4 to 9 pm	84.5	417	35.60	18.3%	85.36	Yes	Yes	58.08	139.27
9/9/2022	4 to 7 pm	70.8	416	3.78	2.0%	9.09	No	No	26.88	64.61
Avg Weekday Event	**4 to 9 pm**	**81.2**	**412**	**36.45**	**18.7%**	**88.53**	**Yes**	**Yes**	**56.44**	**137.11**

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 to the group level. The individual baseline methodology produces estimates that are significantly larger in magnitude than the ex post impacts. For example, the baseline method estimates event load reductions as large as 71.67 MW on September 5, whereas the ex post estimate for the same event is 53.34 MW. While the individual baseline is used to remunerate participant sites 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 3-9.

3.3.2 ELRP Group A.2 Impacts by Event

Group A.2 is designated for non-residential aggregators not participating in DR programs and was comprised of 17 participating sites in PY 2022. There were 10 events called for subgroup A.2 in PY 2022, for a variety of durations and start times. Table 3-5 summarizes the load reductions for ELRP A.2 sites for the 10 events and for the average 4 pm to 9 pm weekday event. The average weekday event reductions were not significant or meaningful in magnitude. In the tables, the orange bars show a visual comparison of the reductions that are numerically labeled on the left of the bars.

Table 3-5 also summarizes the number of sites enrolled and analyzed for each event day. A participant site needed to have data available both for the event and for the relevant proxy day and a matched control needed to have been found to be included in the estimate for a given event.

Aggregate reductions for significant events range from an increase of 16 MW (September 6) to a decrease of 21 MW (September 3). No clear correlation between weather conditions, event window, and load reductions is evident. For example, load reductions varied substantially for the August 31, September 1, September 4, and September 5 events, despite having similar average event temperatures and dispatch windows. Further, load reductions were not significant half of the event days and significance was also not correlated with event temperature. For this reason ex post reductions were not used to develop a weather based load reduction model for the ex ante forecast.

Table 3-5: ELRP Group A.2 Event Reductions

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post)			Significant (90% CI)	Significant (95% CI)	Reductions (Baseline)	
				Aggregate (MW)	% Reduction	Average Site (kW)			Aggregate (MW)	Average Site (kW)
8/17/2022	4 to 9 pm	73.9	16	-0.02	-0.9%	-1.03	No	No	-0.06	-3.71
8/31/2022	5 to 8 pm	78.8	16	0.07	3.6%	4.27	Yes	Yes	0.09	5.78
9/1/2022	6 to 8 pm	77.7	16	0.06	3.1%	3.48	Yes	Yes	0.07	4.66
9/3/2022	6 to 8 pm	85.2	16	0.34	18.3%	21.13	Yes	Yes	0.39	24.68
9/4/2022	5 to 8 pm	81.1	17	0.34	5.5%	19.74	Yes	Yes	0.00	-0.21
9/5/2022	5 to 9 pm	77.7	17	0.10	1.9%	6.18	No	No	0.35	20.78
9/6/2022	4 to 9 pm	78.6	17	-0.28	-5.1%	-16.37	Yes	Yes	-0.07	-3.99
9/7/2022	4 to 9 pm	80.1	17	-0.03	-0.6%	-2.02	No	No	0.03	1.85
9/8/2022	4 to 9 pm	85.2	17	-0.17	-3.1%	-9.80	Yes	No	0.03	1.89
9/9/2022	4 to 7 pm	71.3	17	0.00	0.0%	0.12	No	No	0.48	28.37
Avg Weekday Event	**4 to 9 pm**	**79.5**	**17**	**-0.12**	**-2.7%**	**-7.40**	**No**	**No**	**0.00**	**-0.08**

Estimated load reductions using the baseline method for settlements are presented in the far right columns of Table 3-5 as a basis for comparison. Baseline load reductions are calculated at the individual account level, then aggregated to the group level. The individual baseline methodology produces estimates that are significantly larger in magnitude (for most events) than the ex post impacts. For example, the baseline method estimates event load reductions as large as 0.35 MW on September 5, whereas the ex post estimate for the same event is 0.10 MW. While the individual baseline is used to remunerate participant sites 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 3-9.

3.3.3 ELRP GROUP A.3 IMPACTS BY EVENT

Group A.3 is designated for non-residential rule 21 exporting DERs not participating in DR programs and was comprised of 1 participating site in PY 2022. There were 9 events called for subgroup A.3 in PY 2022, for a variety of durations and start times. Table 3-6 summarizes the load reductions for ELRP A.3 sites for the 9 events and for the average 4 pm to 9 pm weekday event. The average weekday event reductions were not significant or meaningful in magnitude. In the tables, the orange bars show a visual comparison of the reductions that are numerically labeled on the left of the bars.

Table 3-6 also summarizes the number of sites enrolled and analyzed for each event day. A participant site needed to have data available both for the event and for the relevant proxy day and a matched control needed to have been found to be included in the estimate for a given event.

Aggregate reductions for significant events range from [redacted]. No clear correlation between weather conditions, event window, and load reductions is evident. For example, load reductions varied substantially for the August 31, September 1, September 4, and September 5 events, despite having similar average event temperatures and dispatch windows. Further, load reductions were not significant half of the event days and significance was also not correlated with event temperature. For this reason ex post reductions were not used to develop a weather based load reduction model for the ex ante forecast.

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

[redacted]

Estimated load reductions using the baseline method for settlements are presented in the far right columns of Table 3-6 as a basis for comparison. Baseline load reductions are calculated at the individual account level, then aggregated to the group level. The individual baseline methodology produces estimates that track fairly well with ex post estimates, though both of these methods are prone to picking up noise due to the small sample size of Group A.3. While the individual baseline is used to remunerate participant sites 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 3-9.

3.3.4 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 2 participating site in PY 2022. There were 9 events called for subgroup A.5 in PY 2022, for a variety of durations and start times. Table 3-7 summarizes the load reductions for ELRP A.5 sites for the 9 events and for the average 4 pm to 9 pm weekday event. The average weekday event reductions [redacted]

[redacted]

[redacted]

[redacted] No clear correlation between weather conditions, event window, and load reductions is evident. For example, load reductions varied substantially for the September 1, September 4, and September 5 events, despite having similar average event temperatures and dispatch windows. Further, load reductions were not significant for two of the event days and significance was also not correlated with event temperature. For this reason ex post reductions were not used to develop a weather based load reduction model for the ex ante forecast.

Table 3-7: ELRP Group A.5 Event Reductions

[redacted]

Estimated load reductions using the baseline method for settlements are presented in the far right columns of Table 3-7 as a basis for comparison. Baseline load reductions are calculated at the individual account level, then aggregated to the group level. The individual baseline methodology produces estimates that track fairly well with ex post estimates, though both of these methods are prone to picking up noise due to the small sample size of Group A.5. While the individual baseline is used to remunerate participant sites 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 3-9.

3.3.5 ELRP Group B.2 Impacts by Event

Group B.2 is designated for IOU capacity bidding (CBP) PDR resources and was comprised of 118 participating site in PY 2022. There were 8 events called for subgroup B.2 in PY 2022, for a variety of durations and start times. Table 3-8 summarizes the load reductions for ELRP B.2 sites for the 9 events and for the average 4 pm to 9 pm weekday event. The average weekday event reductions were not significant or meaningful in magnitude. In the tables, the orange bars show a visual comparison of the reductions that are numerically labeled on the left of the bars.

Table 3-8 also summarizes the number of sites enrolled and analyzed for each event day. A participant site needed to have data available both for the event and for the relevant proxy day and a matched control needed to have been found to be included in the estimate for a given event.

Aggregate reductions for significant events range from 0.66 MW (September 7) to 1.75 MW (September 9). No clear correlation between weather conditions, event window, and load reductions is evident. For example, load reductions varied substantially for the September 5, September 6, and September 7 events, despite having similar average event temperatures and dispatch windows. Further, load reductions were not significant for two of the event days and significance was also not correlated with event temperature. For this reason ex post reductions were not used to develop a weather based load reduction model for the ex ante forecast.

Table 3-8: ELRP Group B.2 Event Reductions

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post)			Significant (90% CI)	Significant (95% CI)	Reductions (Baseline)	
				Aggregate (MW)	% Reduction	Average Site (kW)			Aggregate (MW)	Average Site (kW)
9/1/2022	6 to 7 pm	78.3	117	0.88	5.3%	7.48	Yes	Yes	2.69	23.01
9/3/2022	6 to 8 pm	86.2	117	0.19	1.1%	1.61	No	No	-0.02	-0.18
9/4/2022	5 to 8 pm	81.3	118	0.13	0.8%	1.07	No	No	1.00	8.45
9/5/2022	5 to 9 pm	77.6	118	0.15	0.9%	1.23	No	No	0.75	6.33
9/6/2022	4 to 9 pm	78.8	118	0.99	6.2%	8.43	Yes	Yes	2.12	17.97
9/7/2022	4 to 9 pm	80.5	117	0.66	4.0%	5.62	Yes	Yes	2.59	22.14
9/8/2022	4 to 9 pm	85.4	117	0.98	6.0%	8.39	Yes	Yes	3.16	27.04
9/9/2022	4 to 7 pm	71.5	117	1.75	10.8%	14.98	Yes	Yes	3.77	32.23
Avg Weekday Event	**4 to 9 pm**	**81.5**	**117**	**0.88**	**5.4%**	**7.48**	**Yes**	**Yes**	**2.62**	**22.37**

Estimated load reductions using the baseline method for settlements are presented in the far right columns of Table 3-8 as a basis for comparison. Baseline load reductions are calculated at the individual account level, then aggregated to the group level. The individual baseline methodology produces estimates that are significantly larger in magnitude (for most events) than the ex post impacts. For example, the baseline method estimates event load reductions as large as 3.77 MW on September 9, whereas the ex post estimate for the same event is 1.75 MW. While the individual baseline is used to remunerate participant sites 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 3-9.

3.3.6 Comparison of Evaluation Load Reductions to Baseline Approach

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

- Group A All Events:
  - Calculate the average 4 to 9 pm load for the prior 10 non-event calendar days.
  - Take the average hour loads across these 10 days. This is the baseline for that customer for that event.

- Calculate a same day adjustment and apply to the average non-event day load: the ratio of the average event day load (first three hours of the four preceding the event) to the same hours on the average non-event day loads[12].
- Subtract observed load from the adjusted baseline. This is the load reduction.
- To determine the kWh eligible for payment, take the positive load reduction in each hour during the event window and sum. No payments or penalties apply to totals below zero kWh for an event hour.

- Group B All Events: follows more detailed rules which include steps for netting out CBP event reductions to avoid double counting

The baseline approach is used to determine settlements for participant sites because it is simple to calculate and simple to explain to customers. Table 3-9 compares the settlement baseline for subgroup A.1 (the vast majority of reductions) to the site specific regressions with synthetic controls approach used for the load impact evaluation and underscores why the latter is more methodologically robust.

Table 3-9: Comparison of Settlement Baseline and Load Impact Evaluation Methodologies

	Settlement Baseline	Load Impact Evaluation
Approach	Within-subjects baseline	Site specific regression with synthetic controls
Does the approach control for exogenous factors?	No. A pre-post within subjects approach only compares participant site 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 synthetic controls.
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. Tournaments are used to select controls and regression models which minimize error and bias. Then results are aggregated across participating sites (hundreds of customers for some subgroups). Noise that is apparent at the individual level is thereby averaged out.
Is the approach symmetrical?	No. The baseline may be adjusted upwards, but not downwards. Also, customers are compensated for positive event reductions but there is no	Yes. Load increases are treated no differently than load reductions.

[12] Capped at minimum 1.00 and maximum 1.40

	Settlement Baseline	Load Impact Evaluation
	penalty for reductions which are negative.	

Figure 3-1 compares the settlement baseline (left panel) averaged across the average 4 to 9 pm 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 ten previous non-event days for each participant site. These days are individually selected for each participant site and are not necessarily the same days for all participant sites. The load impact counterfactual (dotted line in the right panel) is the load modeled using site specific regression models with synthetic controls. Notably, the shape of the load impact counterfactual follows the shape of the observed event day participant site load shape very closely. In contrast, the settlement baseline exhibits a different shape which is essentially pinned to the event day load in pre-event hours (as a result of the baseline adjustment). This demonstrates that participant site loads on event days are different than participant site loads on baseline days. In this case, the baseline exhibits a flatter shape than the event day loads. This results in a load reduction estimate that is based on a baseline that does not follow the shape of loads on event days.

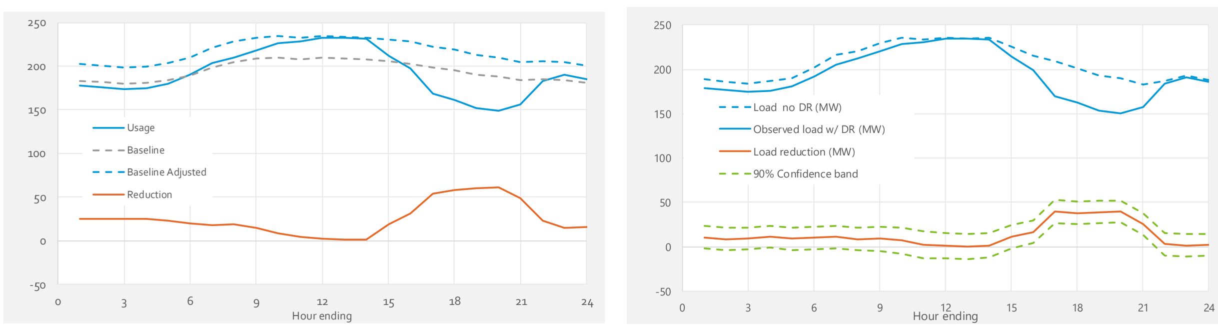
Figure 3-1: ELRP A.1 Average Weekday Event Load Impact Compared to Baseline

Settlement Baseline - Aggregate (MW)

Event load reduction (MW)	56.44
Event % load reduction	29.6%

Load Impact Evaluation - Aggregate (MW)

Avg load reduction (Event Window)	36.45
% Load reduction (Event Window)	18.7%



Incorporating a post event adjustment may somewhat reduce the gap in post event hours but would still not result in an adjusted load shape that follows event day loads in most non-event hours. In addition, the current baseline rules are asymmetrical and only allow for upward adjustments of the baseline. This means that the baseline could not be adjusted downwards to better align with post-event loads.

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. However, load reductions did not exhibit clear patterns by these parameters. Further, most participating sites have dispatchable generating interconnected and reductions appear to be directly driven by dispatchable generation capacity rather than curtailment of weather sensitive loads. As such, historical load patterns were not used to derive the ex ante forecast and the forecast is not differentiated by weather conditions. Rather, capacity enrollments were forecast as a portion of total interconnected dispatchable generation that can feasibly be enrolled. Enrollments are derated for performance during actual events, relative to nominated reductions specified by enrollees at the time of enrollment.

3.4.1 Ex Ante Enrollment Forecast

As summarized in Figure 2, the ex ante forecast model uses historical interconnection data to derive the ex ante load reduction estimates. Essentially, historical interconnected capacity and growth rates are used to project future interconnected capacity. The technical potential for the program is deemed to be the remainder of forecasted interconnection capacity after subtracting the portion of capacity assumed to be typically used for daily operations the portion expected to be reserved for on-site back-up of other purposes. The feasible potential incorporates expected limits on enrollment. Enrollments for PY 2022 are tied to the reduction capacity nominated by participant sites in PY 2022. The expected impacts further incorporate derating of battery storage capacity to reflect duration limits. Forecasted reductions for PY 2022 are tied to average MW reductions across all events. They are not tied to the average weekday event because no clear pattern was observed by weather, day type, duration or event window. Actual PY 2022 reductions are used to derive a performance factor, relative to nominated capacity. This performance factor is then carried through subsequent years.

Figure 2: Non-Residential ELRP Ex Ante Model Architecture

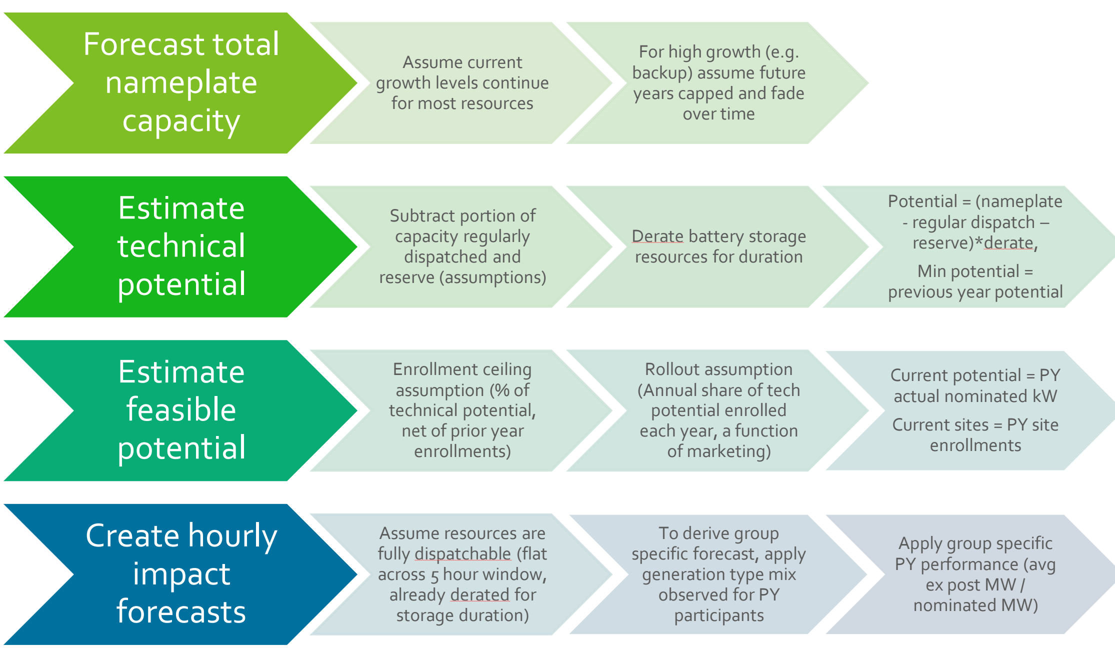


Figure 3 shows the cumulative historical generation capacity for the six dispatchable generation categories included in the forecast. Note that non-dispatchable sources, e.g. solar and wind, were excluded from the forecast. The six dispatchable following categories, analyzed separately for non-residential and residential customers, are as follows:

- Turbine: combustion turbines, microturbines, steam turbines, hydro turbines
- Combustion: combustion engines
- Fuel cell: all fuel cells
- Back up generation
- Storage+: storage collocated with other generation (mostly solar)
- Storage: storage NOT collocated with other generation

The largest and longest standing sources of generation capacity are non-residential turbines and combustion engines which comprise about 60% of total non-residential interconnections in 2022. Back up generation, which comprised another 10%, is the non-residential generation type exhibiting the most rapid growth in recent years, possibly in response to Public Safety Power Shutoffs (PSPS) which have been deployed in the last few years to ensure safe grid operations. Residential interconnections were considered specifically in the context of subgroup A.4, Virtual Power Plants, presumed to be comprised of aggregations of residential battery storage. Residential backup generation has similarly more than doubled annually for the past two years. However, only residential battery storage was considered, assuming that other residential generation would not be eligible for or targeted by ELRP aggregation.

Figure 3: Historical Cumulative Interconnection Capacity

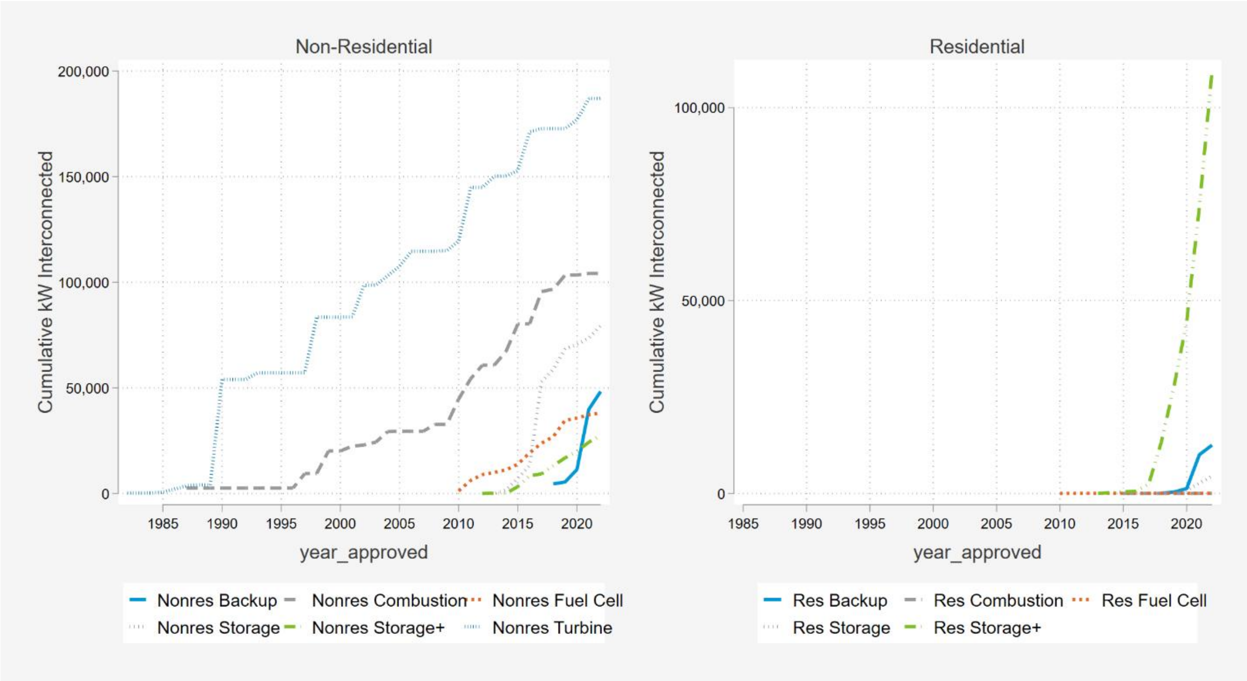


Table 3-10 summarizes the annualized growth rates by generation category. The model incorporated annualized growth rates of the past two years, from January 2020 to December 2021. To further smooth likely unsustainably large capacity increases such as for backup and residential stand-alone solar, all modeled growth rates were capped at 100% (annual doubling) and assumed to decrease by 25% each year. As an example, year over year growth rate of 100% in 2022 would decrease to 18% year over year growth in 2028.

Table 3-10: Recent Dispatchable Generation Growth Rates

Class	Dispatchable Generation Category	Annualized growth (2020 to 2021)	Annualized growth (2019 to 2021)
Non-Residential	Backup	21%	100%
	Combustion	0%	0%
	Fuel Cell	2%	3%
	Storage	8%	6%
	Storage+ (collocated)[13]	14%	17%
	Turbine	0%	3%
Residential	Storage	66%	100%
	Storage+ (collocated)	48%	57%

[13] Solar growth rates shown and used for collocated storage which typically follows growth rates for solar (comprises the bulk of collocated generation)

Table 3-11 summarizes the additional assumptions made for each step in the model. As noted above, historical growth rates were extrapolated but capped. Technical potential was essentially assumed to be 25% of forecasted capacity, after subtracting 35% for typical operations and 25% reserved for other on-site purposes. Data was not available to inform these assumptions due to the inability to link generation interval data and interconnection capacity. These assumptions could be refined if this data became available in the future. Feasible potential was capped at 50% of technical potential and ramped annually so that total feasible potential is close to being reached by 2028. Hourly impacts assume flat generation shapes, given the dispatchable nature of these resources. Impacts for battery storage are derated to reflect duration limitations. Growth and enrollment forecasts by dispatchable generation category were allocated to each subgroup based on the mix generation capacity interconnected by participating sites in each subgroup for PY 2022.

Table 3-11: Forecast Model Assumptions

Analysis Step	Assumption	Definition
Capacity Forecast	Annualized growth rates	Growth from 2020 to 2022 based on DSA analysis of SDG&E historical interconnections provided by SDG&E. Growth rates were capped at 100% and rates above 15% were decreased annually by 25% until they reached 15%.
Technical Potential	Routine capacity	Portion of capacity assumed to be reserved for daily or routine operations. Assumed to be 50% for all non-residential generation categories. Assumed to be 10% for residential storage, reflecting operations observed for the Residential CBP pilot.
	Reserved capacity	Portion of capacity assumed to be reserved for on site backup or other purposes. Assumed to be 25% for all non-residential generation categories. Assumed to be 35% for residential storage.[14]
Feasible Potential	Enrollment ceiling	Maximum attainable share of technical potential, analogous to program share of the market. Given the strong enrollment growth from PY 2021 to PY 2022, assumed to be 25%, which aligns with the "high" growth scenario assumed for SDG&E's 2022 DR Application.
	New annual enrollment cap	Share of attainable enrollment that can be enrolled in a single year. Assumed to be 50%, so assuming 25% of technical potential), 12.5% (=25% * 50%) of technical potential can be enrolled in a given year[15]
	Attrition	Portion of enrolled capacity that leaves the program each year. Assumed to be 5%, based on experience with commercial programs

[14] In a recent PG&E residential battery pilot, participants elected to make 65% of their capacity available for events, implying a 35% capacity reservation

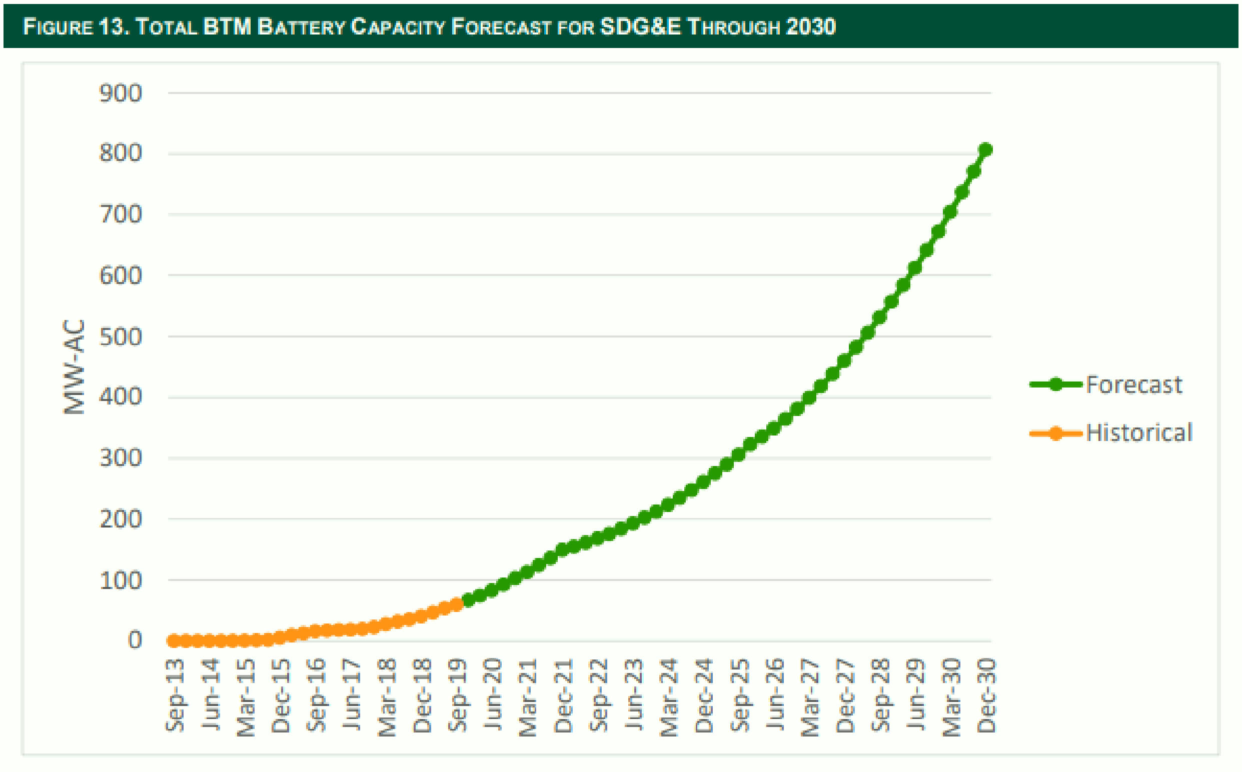
[15] This puts annual enrollment in line with the first year enrollments seen for PY 2022

Analysis Step	Assumption	Definition
Hourly Impacts	Impacts by month and hour	Impacts are only assumed to be non-zero for months and hours where the program operates: May through October, 4pm to 9pm. Impacts are assumed to be the same for all event months and hours, given that all resources are dispatchable
	Shape of impacts	Assumed to be flat in all program hours (4pm to 9pm), given that all resources are dispatchable
	Battery duration	Battery duration is not recorded in interconnection data but typically ranges from 2 to 4 hours. Average duration was assumed to be 3 hours, so battery capacity was derated by 3/5 to derive average reductions for the 5-hour ELRP window.

As an external check for forecasted growth assumptions, the aggregate storage forecast was compared to a more sophisticated bass diffusion model executed for a separate behind the meter ETCC study, cited in Figure 4. The ETCC study forecast of between 450 MW and 500 MW for 2027 aligns reasonably well with the 540 MW forecast for this evaluation using the simple growth model, after factoring in recent strong growth in storage and the vintage of the ETCC study[16].

[16] https://www.etcc-ca.com/reports/behind-meter-battery-market-study. Based on interconnection data through 2019

Figure 4: SDG&E Forecast of Total Behind the Meter Battery Capacity[17]



3.4.2 ELRP Group A.1 Ex Ante Load Impacts

Group A.1 is designated for non-residential customers not participating in DR programs and is currently by far the largest ELRP subgroup with over 400 participating sites. Table 3-12 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 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 enrolled dispatchable generation capacity, not reductions in weather sensitive loads.

Estimates for enrolled capacity are based on the enrollment forecast model described above and are anchored to reductions observed across all events in PY 2022. Enrollments are assumed to grow slowly thereafter because the large customers likely to enroll have already enrolled. Enrollment growth is expected to come from smaller sites.

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[17] https://www.etcc-ca.com/reports/behind-meter-battery-market-study

Table 3-12: Group A.1 Impacts for August Monthly Peak Day

Year	Sites	CAISO		SDG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2022	474[18]	28.01	28.01	28.01	28.01
2023	484	28.90	28.90	28.90	28.90
2024	492	29.82	29.82	29.82	29.82
2025	497	30.67	30.67	30.67	30.67
2026	503	31.68	31.68	31.68	31.68
2027	509	32.69	32.69	32.69	32.69
2028	514	33.53	33.53	33.53	33.53
2029	514	33.53	33.53	33.53	33.53
2030	514	33.53	33.53	33.53	33.53
2031	514	33.53	33.53	33.53	33.53
2032	514	33.53	33.53	33.53	33.53
2033	514	33.53	33.53	33.53	33.53

3.4.3 ELRP Group A.2 Ex Ante Load Impacts

Group A.2 is designated for non-residential aggregators not participating in DR programs and was comprised of 17 participating sites in PY 2022. Table 3-13 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 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 enrolled dispatchable generation capacity, not reductions in weather sensitive loads.

Estimates for enrolled capacity are based on the enrollment forecast model described above and are anchored to reductions observed across all events in PY 2022. Enrollments are assumed to grow slowly thereafter because the large customers likely to enroll have already enrolled. Enrollments are expected to remain essentially flat for this group.

[18] Excludes 54 participants that enrolled after the last PY 2022 event

Table 3-13: Group A.2 Impacts for August Monthly Peak Day

Year	Sites	CAISO		SDG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2022	17	0.04	0.04	0.04	0.04
2023	17	0.04	0.04	0.04	0.04
2024	18	0.04	0.04	0.04	0.04
2025	18	0.04	0.04	0.04	0.04
2026	18	0.05	0.05	0.05	0.05
2027	18	0.05	0.05	0.05	0.05
2028	18	0.05	0.05	0.05	0.05
2029	18	0.05	0.05	0.05	0.05
2030	18	0.05	0.05	0.05	0.05
2031	18	0.05	0.05	0.05	0.05
2032	18	0.05	0.05	0.05	0.05
2033	18	0.05	0.05	0.05	0.05

3.4.4 ELRP Group A.3 Ex Ante Load Impacts

Group A.3 is designated for non-residential rule 21 exporting DERs not participating in DR programs and was comprised of 1 participating site in PY 2022. Table 3-14 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 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 enrolled dispatchable generation capacity, not reductions in weather sensitive loads.

Estimates for enrolled capacity are based on the enrollment forecast model described above and are anchored to reductions observed across all events in PY 2022. Enrollments are assumed to grow slowly thereafter because the large customers likely to enroll have already enrolled. Enrollments are expected to remain essentially flat for this group.

Table 3-14: Group A.3 Impacts for August Monthly Peak Day

Year	Sites	CAISO		SDG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Year	Sites	CAISO		SDG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

3.4.5 ELRP Group A.4 Ex Ante Load Impacts

Group A.4 is designated for Virtual Power Plant (VPP) aggregators not participating in DR programs. There were no enrollments in PY 2022 but aggregators are expected to enroll beginning in PY 2023. Table 3-15 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 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 enrolled dispatchable generation capacity, not reductions in weather sensitive loads. To derive expected impacts enrolled capacity is derated to take into account battery durations which are shorter than the full 5 hour RA window.

Estimates for enrolled capacity are based on the enrollment forecast model described above and are anchored to reductions observed across all events in PY 2022. Enrollments are assumed to begin in PY 2023 and ramp quickly thereafter until roughly 25% of residential energy storage is enrolled.

Table 3-15: Group A.4 Impacts for August Monthly Peak Day

Year	Sites	CAISO		SDG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2022	0	0.00	0.00	0.00	0.00
2023	1,154	2.26	2.26	2.26	2.26
2024	3,206	6.27	6.27	6.27	6.27
2025	4,945	9.70	9.70	9.70	9.70
2026	5,975	11.76	11.76	11.76	11.76
2027	6,731	13.27	13.27	13.27	13.27

Year	Sites	CAISO		SDG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2028	7,536	14.87	14.87	14.87	14.87
2029	7,536	14.87	14.87	14.87	14.87
2030	7,536	14.87	14.87	14.87	14.87
2031	7,536	14.87	14.87	14.87	14.87
2032	7,536	14.87	14.87	14.87	14.87
2033	7,536	14.87	14.87	14.87	14.87

3.4.6 ELRP Group A.5 Ex Ante Load Impacts

Group A.5 is designated for non-residential vehicle-grid integration (VGI) aggregators not participating in DR programs and was comprised of [redacted] in PY 2022. Table 3-16 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 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 enrolled dispatchable generation capacity, not reductions in weather sensitive loads.

Estimates for enrolled capacity are based on the enrollment forecast model described above and are anchored to reductions observed across all events in PY 2022. Enrollments are assumed to grow slowly thereafter because the large customers likely to enroll have already enrolled. Enrollments are expected to remain essentially flat for this group.

Table 3-16: Group A.5 Impacts for August Monthly Peak Day

Year	Sites	CAISO		SDG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Year	Sites	CAISO		SDG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2033	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

3.4.7 ELRP Group B.2 Ex Ante Load Impacts

Group B.2 is designated for IOU capacity bidding (CBP) PDR resources and was comprised of 118 participating site in PY 2022. Table 3-17 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 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 enrolled dispatchable generation capacity, not reductions in weather sensitive loads.

Estimates for enrolled capacity are based on the enrollment forecast model described above and are anchored to reductions observed across all events in PY 2022. Enrollments are assumed to grow slowly thereafter because the large customers likely to enroll have already enrolled. Enrollments are expected to remain essentially flat for this group.

Table 3-17: Group B.2 Impacts for August Monthly Peak Day

Year	Sites	CAISO		SDG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2022	121	0.72	0.72	0.72	0.72
2023	123	0.76	0.76	0.76	0.76
2024	125	0.79	0.79	0.79	0.79
2025	127	0.80	0.80	0.80	0.80
2026	128	0.82	0.82	0.82	0.82
2027	130	0.84	0.84	0.84	0.84
2028	131	0.86	0.86	0.86	0.86
2029	131	0.86	0.86	0.86	0.86
2030	131	0.86	0.86	0.86	0.86
2031	131	0.86	0.86	0.86	0.86
2032	131	0.86	0.86	0.86	0.86
2033	131	0.86	0.86	0.86	0.86

3.4.8 Comparison of Ex Post and Ex Ante Load Impacts

Table 3-18 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. The ex post analysis showed no trend in reductions by weather patterns and are therefore assumed to not be not weather sensitive. Ex ante load reductions are instead assumed to be a function of enrolled dispatchable generation capacity, not reductions in weather sensitive loads.

In 2022, ELRP customers delivered 37.21 MW for the average 4 to 9 pm event. This event window also aligns with the 4 to 9 pm resource adequacy window. The SDG&E and CAISO weather ex ante predictions are the same because ex ante load reductions were assumed to not be weather sensitive. The ex ante estimates for PY 2022 were notably lower than the ex post reduction because they were anchored to the average hourly load reduction across all event hours, not just the average 4 to 9 pm event. In practice this means that the ex ante reductions are tied to ex post reductions, but are simply summarized differently.

Table 3-18: Non-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	Daily Max Temp (F)	Event Avg Temp (F)
Ex Post Avg. Weekday	Resource Adequacy Period (4 to 9 pm)	549	216.27	37.21	17.2%	81.2	91.7
Ex ante SDG&E	1-in-2 Weather August Peak (4 to 9 pm)	615**	28.80	28.80	100.0%	85.4*	94.0*
Ex ante CAISO	1-in-2 Weather August Peak (4 to 9 pm)	615**	28.80	28.80	100.0%	81.3*	89.0*

*Miramar weather used to represent ex ante conditions in this table
** Includes 54 A.1 participant sites that enrolled after the last PY 2022 event

3.4.9 Ex Ante Load Impact Slice-of-Day Tables

Table show the 2022 ex ante aggregate hourly impacts by ELRP Group for each month under SDG&E monthly peaking conditions.[19] The tables are designed to enable the CPUC's Slice-of-Day Resource Adequacy requirements. The estimated reductions are equal in all months, as ex ante reductions for ELRP are not weather sensitive. Response to an event is flat across the five-hour Resource Adequacy window. Note that Group A.4 is not included as there were zero forecasted load impacts for 2022.

Table 3-19: Group A.1 Slice of Day Table for Monthly Peak Day (Aggregate Impacts (MW))

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01
18	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01
19	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01
20	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01
21	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01
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)												

[19] Ex ante reductions are identical for SDG&E 1-in-2, SDG&E 1-in-10, CAISO 1-in-2, and CAISO 1-in-10 weather.

Table 3-20: Group A.2 Slice of Day Table for Monthly Peak Day (Aggregate Impacts (MW))

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
18	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
19	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
20	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
21	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
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 3-21: Group A.3 Slice of Day Table for Monthly Peak Day (Aggregate Impacts (MW))

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
18	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
19	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
20	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
21	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
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 3-22: Group A.5 Slice of Day Table for Monthly Peak Day (Aggregate Impacts (MW))

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
18	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
19	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
20	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
21	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
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 3-23: Group B.2 Slice of Day Table for Monthly Peak Day (Aggregate Impacts (MW))

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72
18	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72
19	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72
20	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72
21	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72
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 non-residential ELRP pilots 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 ELRP RECOMMENDATIONS

- **Collect data to inform assumptions regarding percent of dispatchable generation capacity available for participation in ELRP**. Load reductions observed for PY 2022 events did not appear correlated with weather conditions and may be more a function of the availability of generation capacity for reductions. A better understanding of resource availability will better inform load reduction forecasting. This may include process surveys or interviews with the large non-residential customers that comprise most of ELRP participant sites.

- **Consider updates to baseline adjustment rules.** While a load impact evaluation approach which incorporates controls for exogenous factors provides the most robust estimate of actual load reductions, ELRP participant sites are remunerated for reductions based on baseline methodology. This includes a pre-event adjustment which is asymmetrical because it can only adjust the baseline upwards, not downwards. Incorporating a post event adjustment may somewhat reduce the gap observed between the adjusted baseline and observed loads in post event hours. Incorporating symmetrical adjustment rules would allow for downwards adjustment for better alignment with post-event loads.

APPENDIX

A. INDIVIDUAL SITE REGRESSIONS WITH SYNTHETIC CONTROLS

Individual site regressions with synthetic controls and site specific specifications were used as the primary method for estimating load impacts for PY 2022 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 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.
$\mathrm{kW\_0}_t$	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.
$\mathrm{kW\_1}_{t-n}$	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.
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.