OhmConnect 2020 LIP Evaluation

OhmConnect

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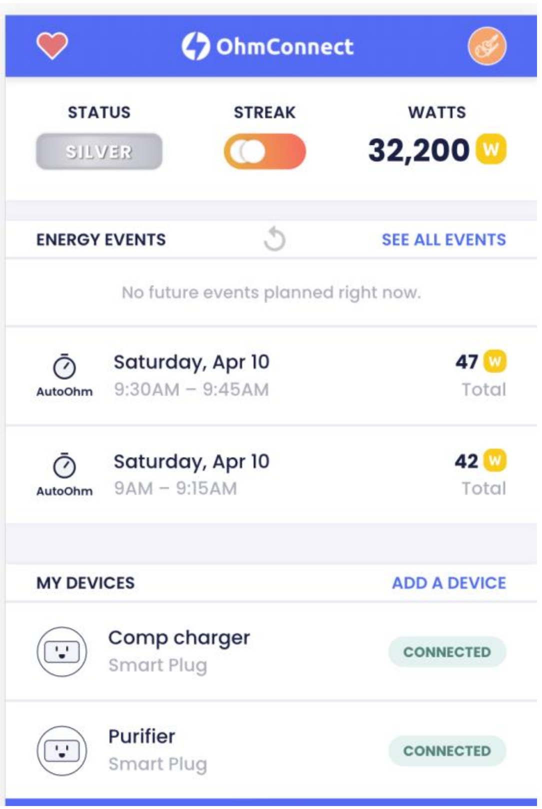
Convergence Data Analytics

About OhmConnect

- OhmConnect is a free service that rewards residential customers for saving energy when it matters most to the grid and the environment: "*Save Energy. Get Paid*"
- Demand response events, which vary between one and four hours, are called *OhmHours*
- Users are typically notified a full day ahead that an OhmHour is scheduled—OhmConnect notifies users once it receives notice of a DAM award
- Rewards are proportional to the amount of energy saved
- Users participate in OhmHours behaviorally, by shutting off devices inside the home, and automatically, through devices controlled by OhmConnect
- OhmConnect users receive a different status—Bronze, Silver, Gold, Platinum, or Diamond—based on how much energy they've saved, on average, during their OhmHours

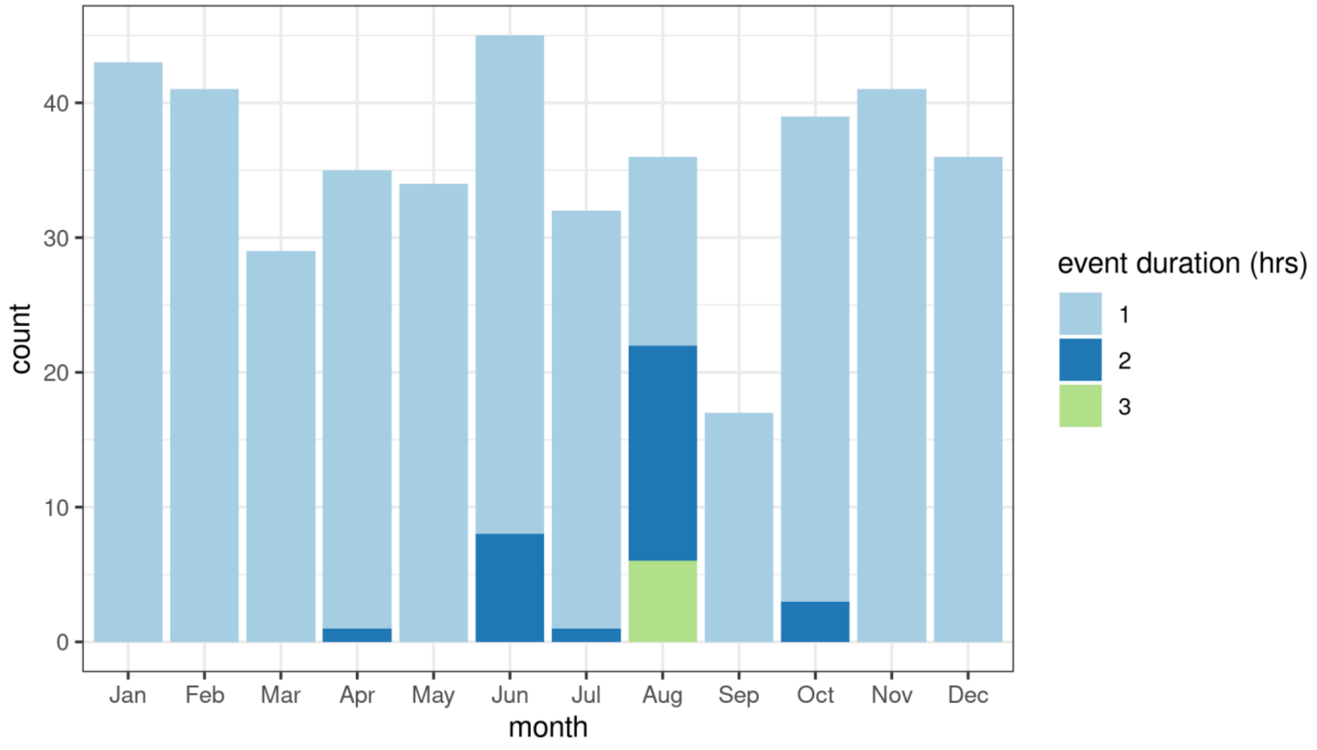


Events called in 2020

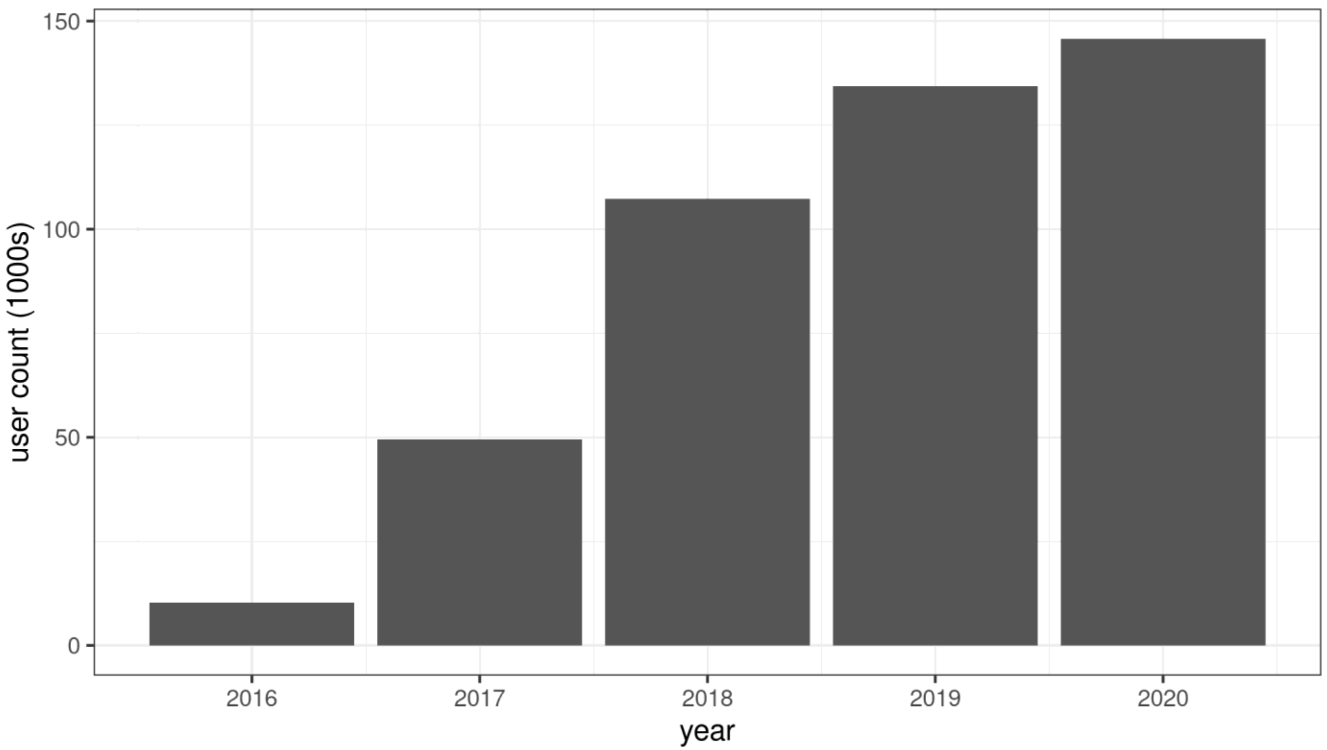
Events are defined by a unique combination of date, utility, event types, and start and end times.

In 2020, 428 events occurred on 119 days, with multiple events being called on the same day.

start	count
4 pm	5
5 pm	35
6 pm	117
7 pm	177
8 pm	94
Total	428

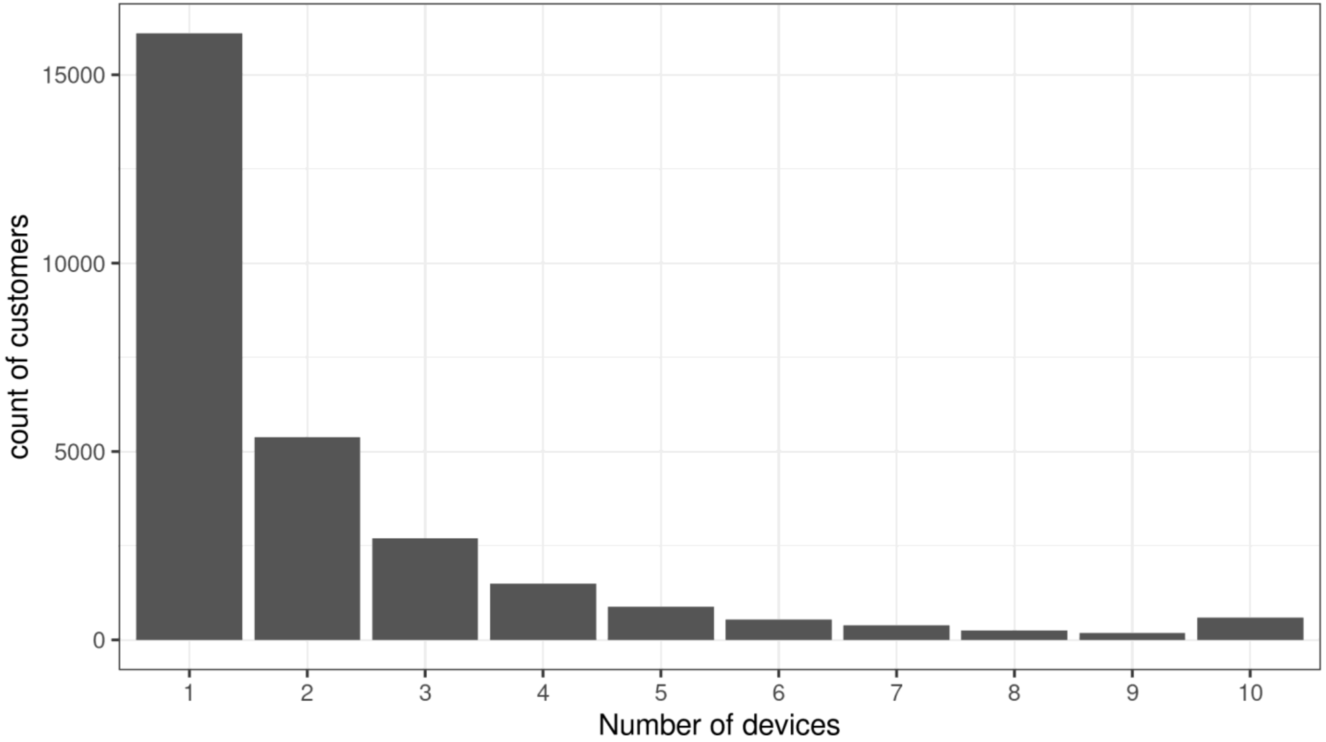


Annual unique participants



Devices and tiers

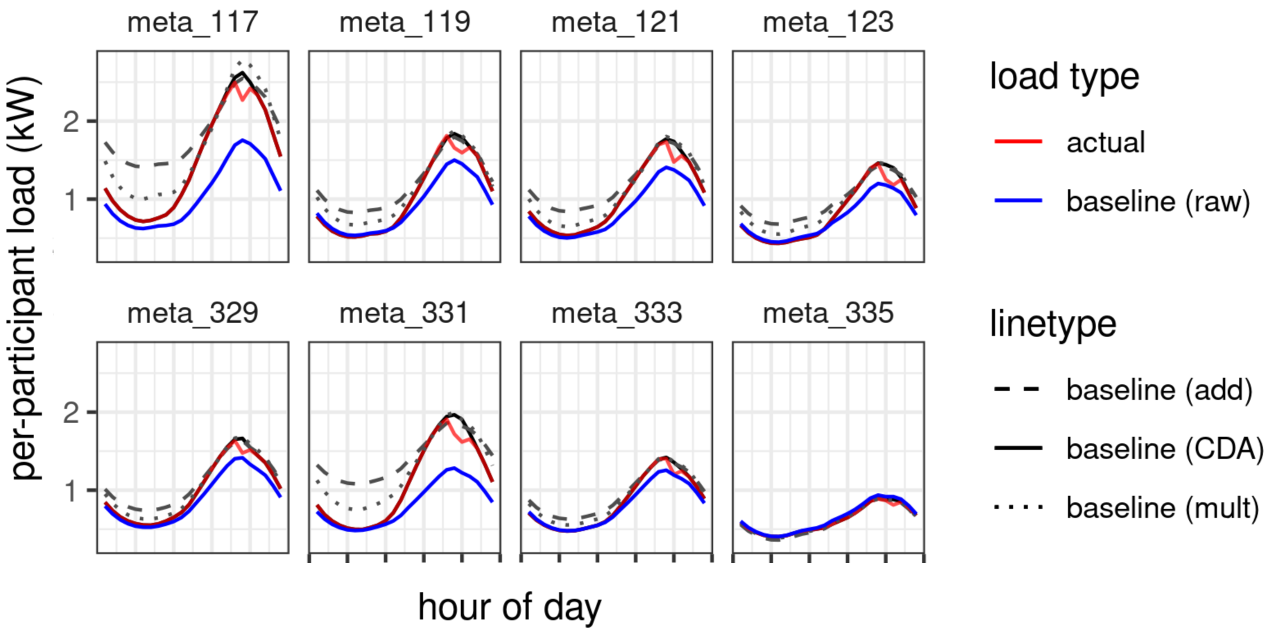
tier	% of customers in tier	% of tier with devices	% of devices in tier
Silver (and below)	43%	16%	36%
Gold	36%	18%	34%
Platinum (and above)	21%	27%	30%



Ex post

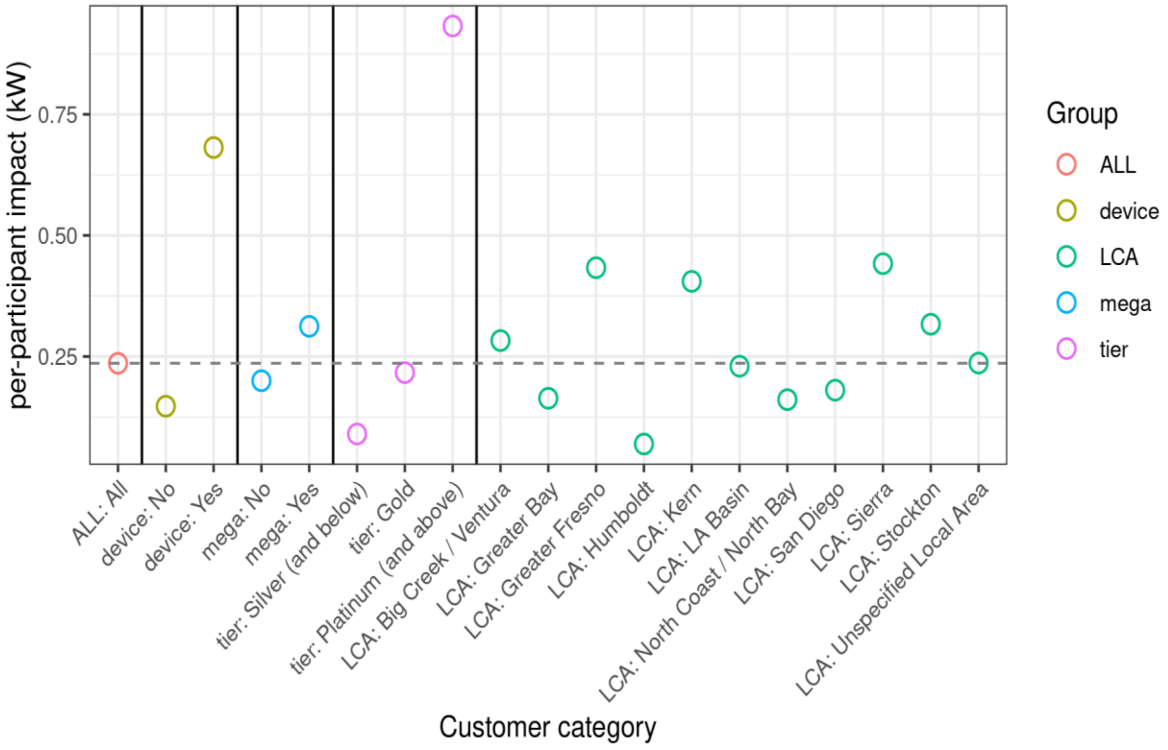
Ex post methods

- 5 of 10 baselines
- Adaptive additive same day adjustments

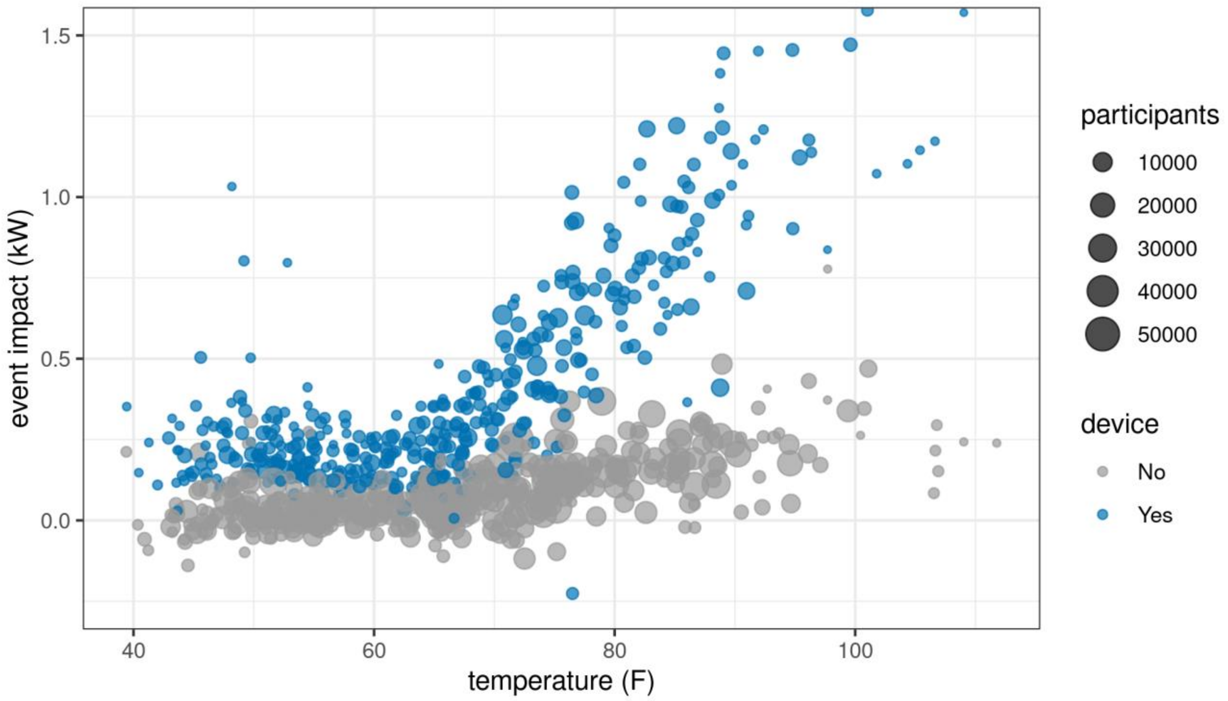


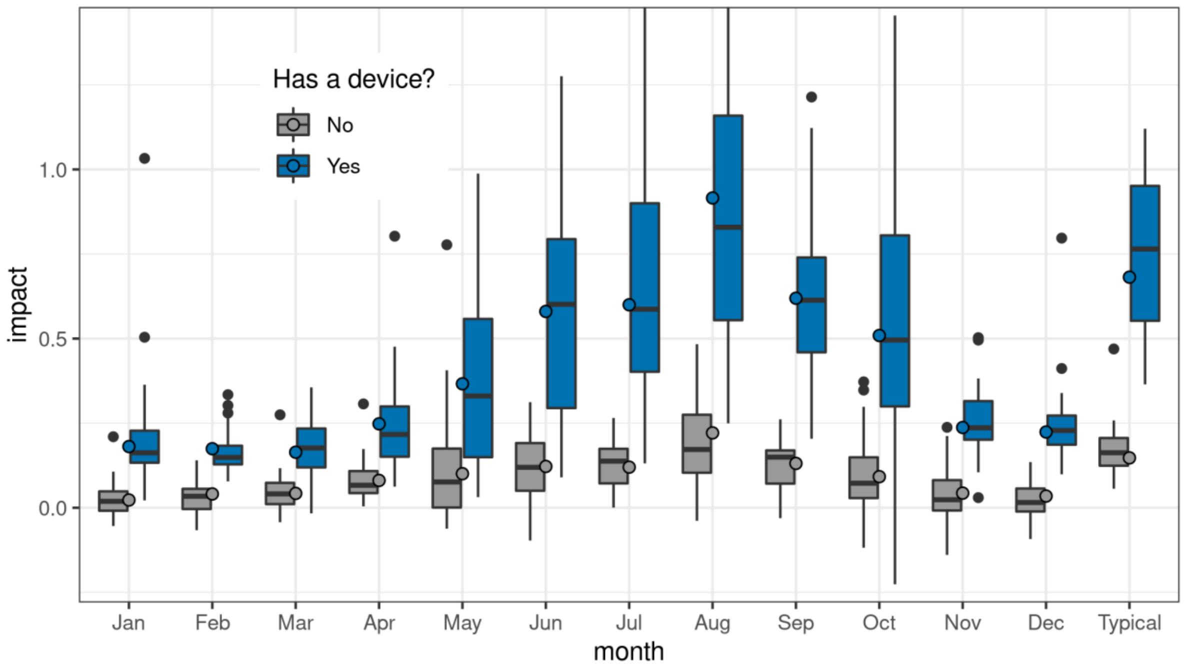
Ex post summary

Group	Category	# unique participants	Average temp. (F)	per-participant ref. (kW)	Per-participant impact (kW)	Impact (% of ref)
ALL	All	126,908*	78.48	1.6	0.24	14.72
device	No	110,697	78.57	1.59	0.15	9.29
	Yes	25,726	78.03	1.68	0.68	40.45
tier	Silver (and below)	114,243	78.98	1.71	0.09	5.27
	Gold	85,072	76.2	1.26	0.22	17.21
	Platinum (and above)	51,433	78.62	1.5	0.93	62.19
	*Note that typical events are for the period from June-September, so do not represent all events.					



Device owner performance

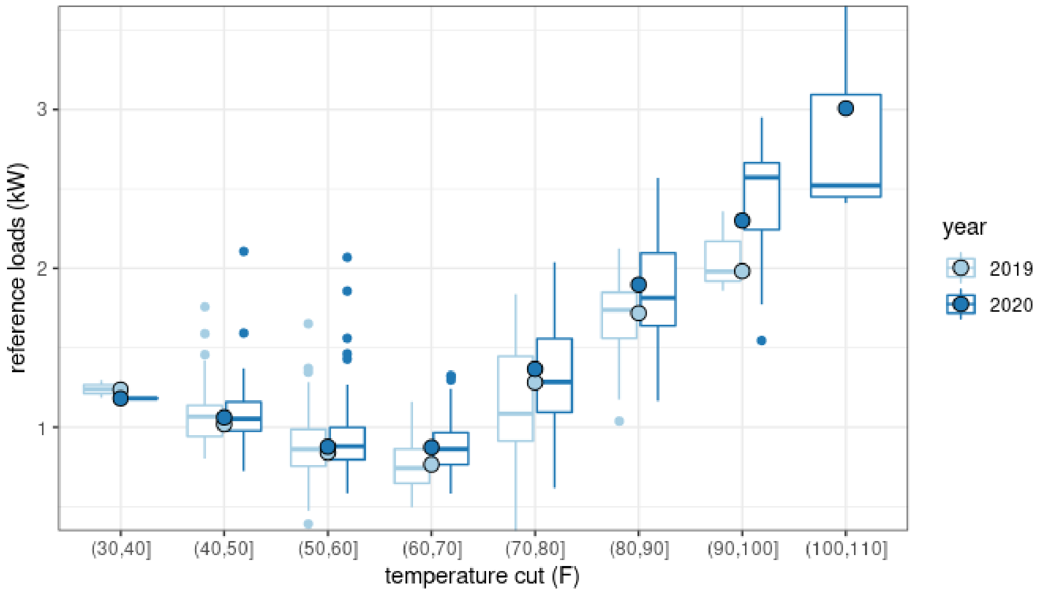




Special topics

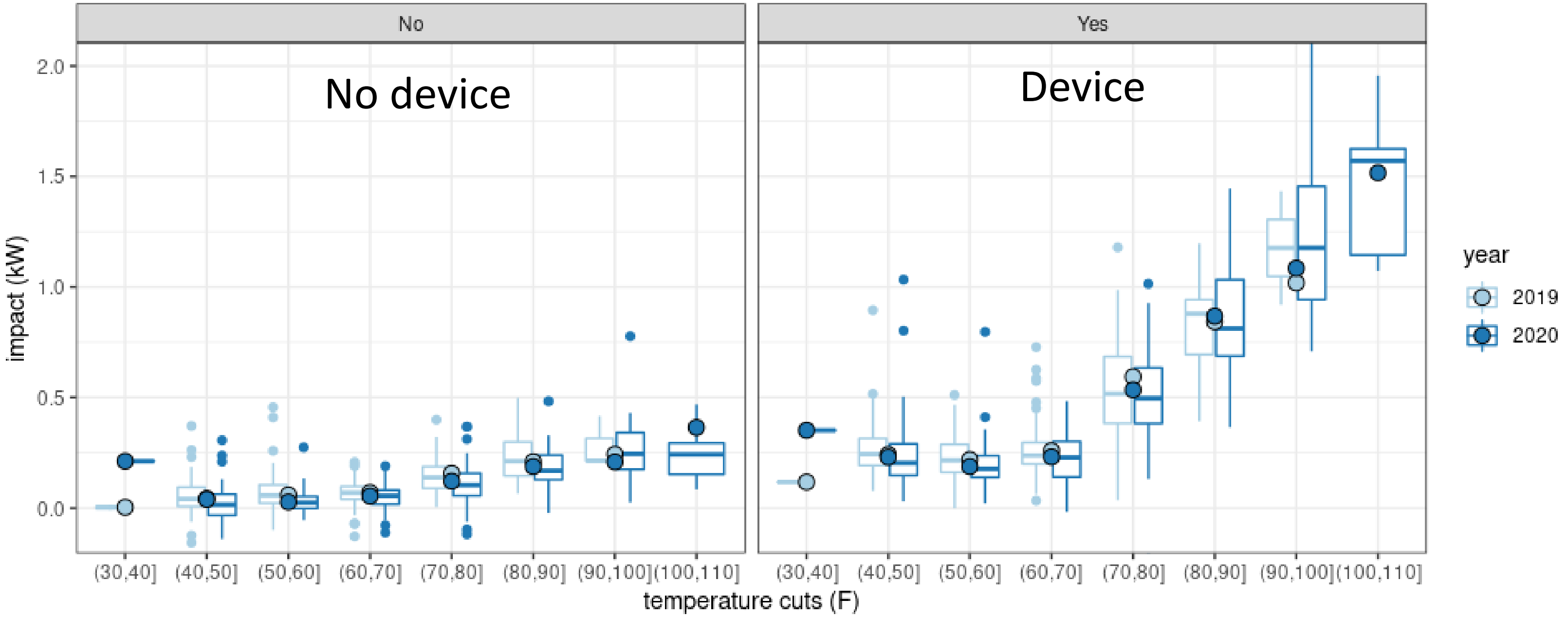
COVID-19: Per-participant reference loads

- Compare 2019 (normal) to 2020 (COVID-19) outcomes under similar conditions
- Higher reference loads in 2020

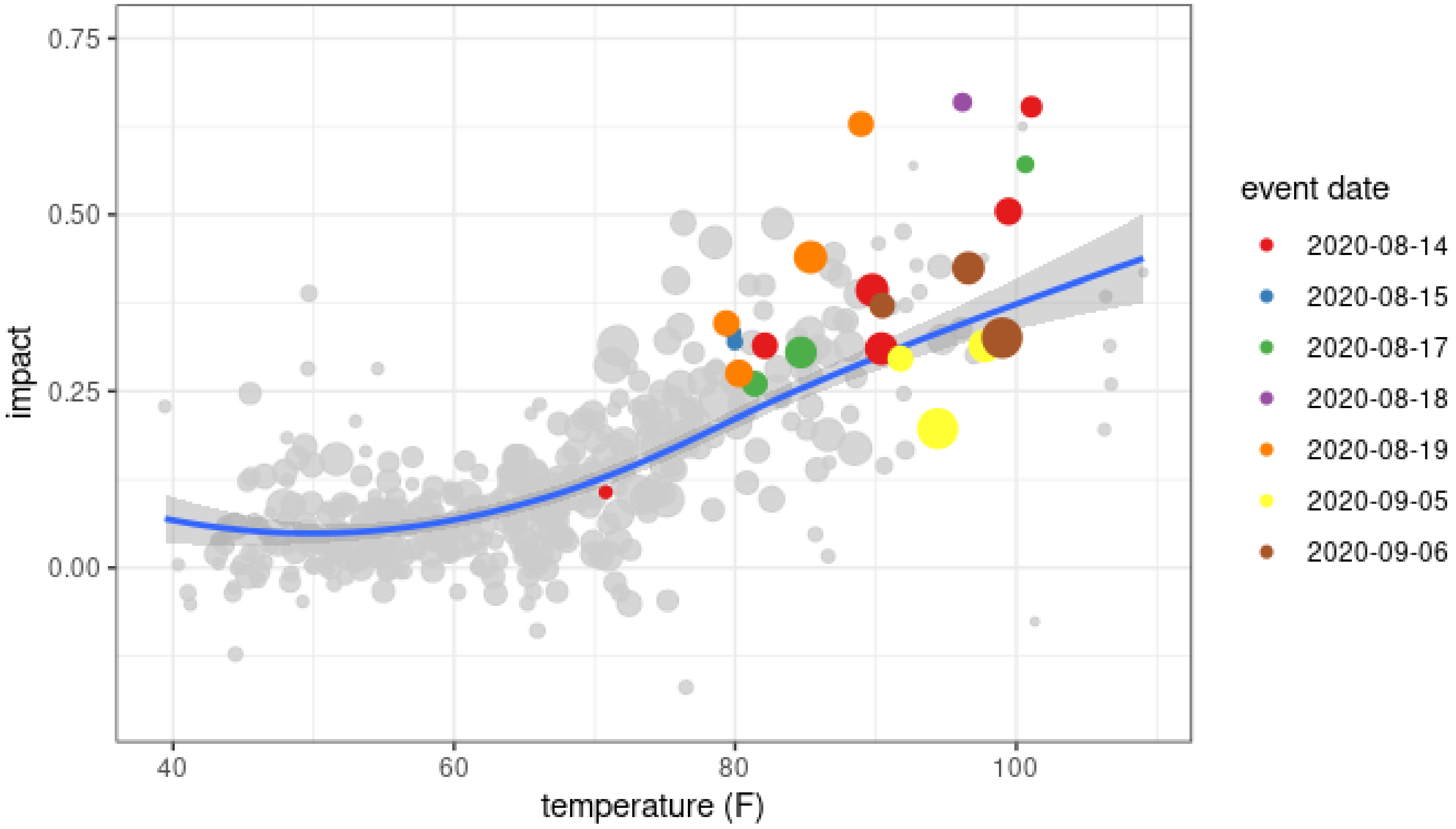


COVID-19: Per-participant impacts

- Slight under-performance without devices in 2020 vs. 2019
- Devices exceeded 2019 predictions in warm weather from 2020
- Ex ante adjustment based on weighted average of 2019 vs. 2020 ex ante predictions
- The adjustment changes the forecasted load impact for a 1-in-2 event day in summer by less than 0.02 kW (less than 3%)



Grid emergency performance

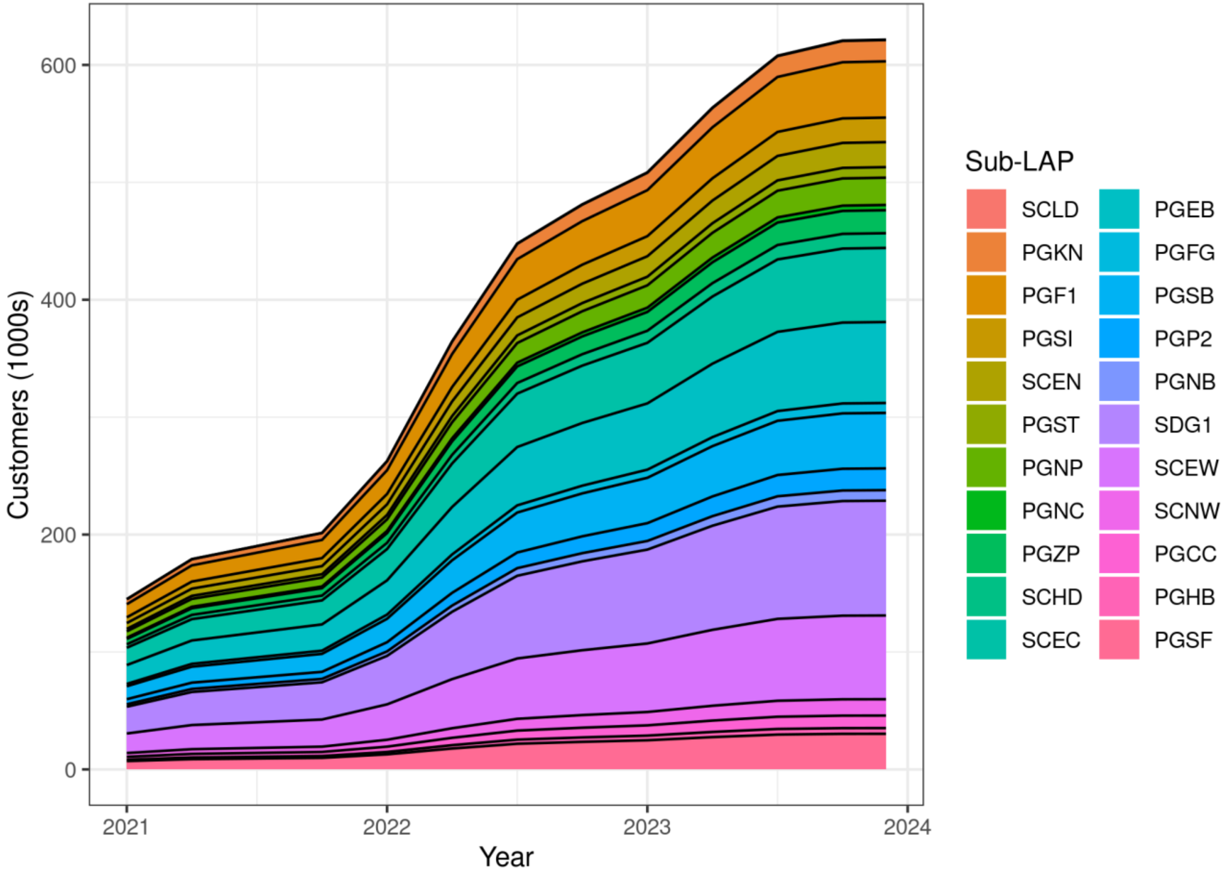


Ex ante

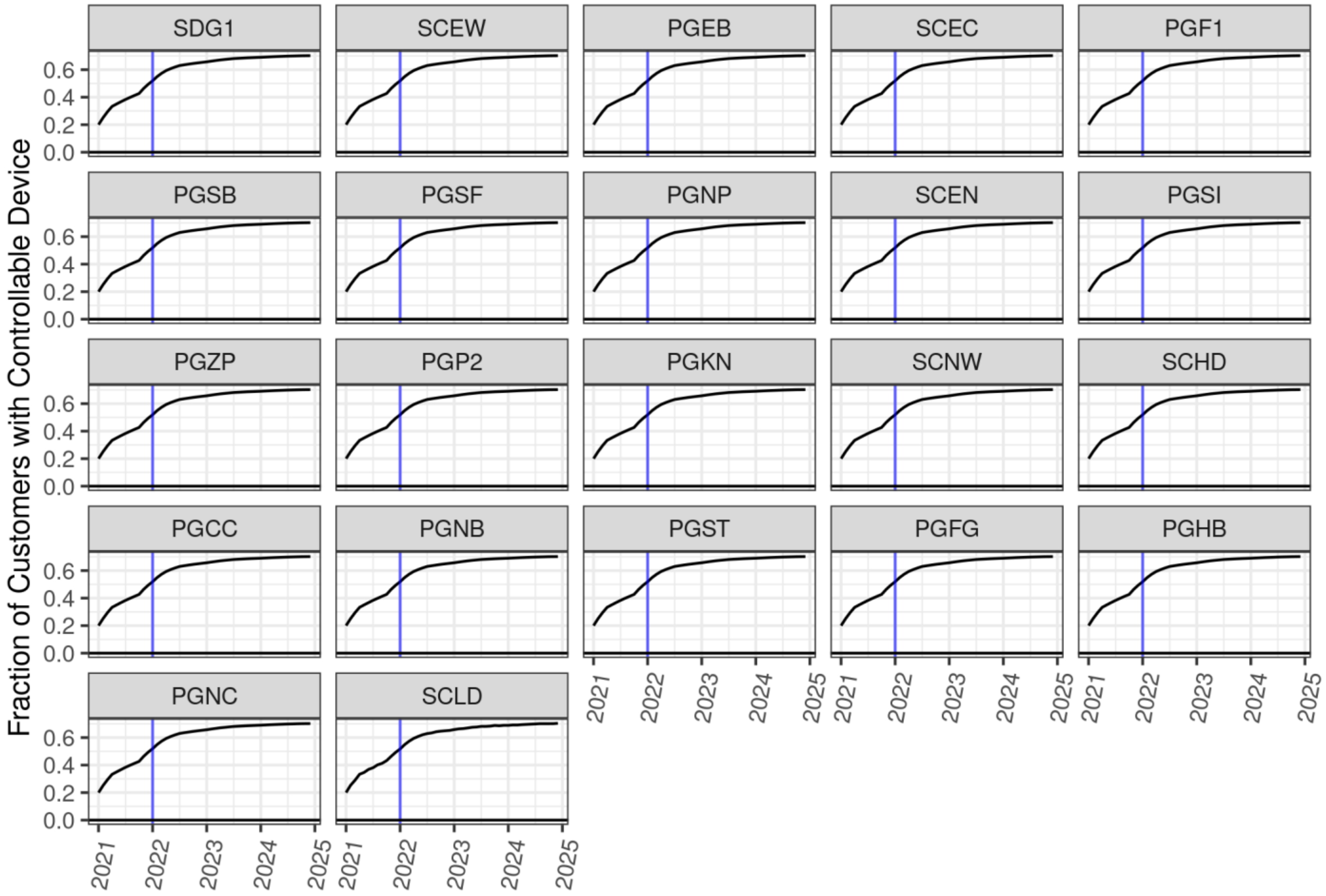
Ex ante methods

- Ex post events as inputs into ex ante regression model
- Primary explanatory variables: temperature, hour of day, device, tier, sub-LAP

Projected enrollment - Medium scenario

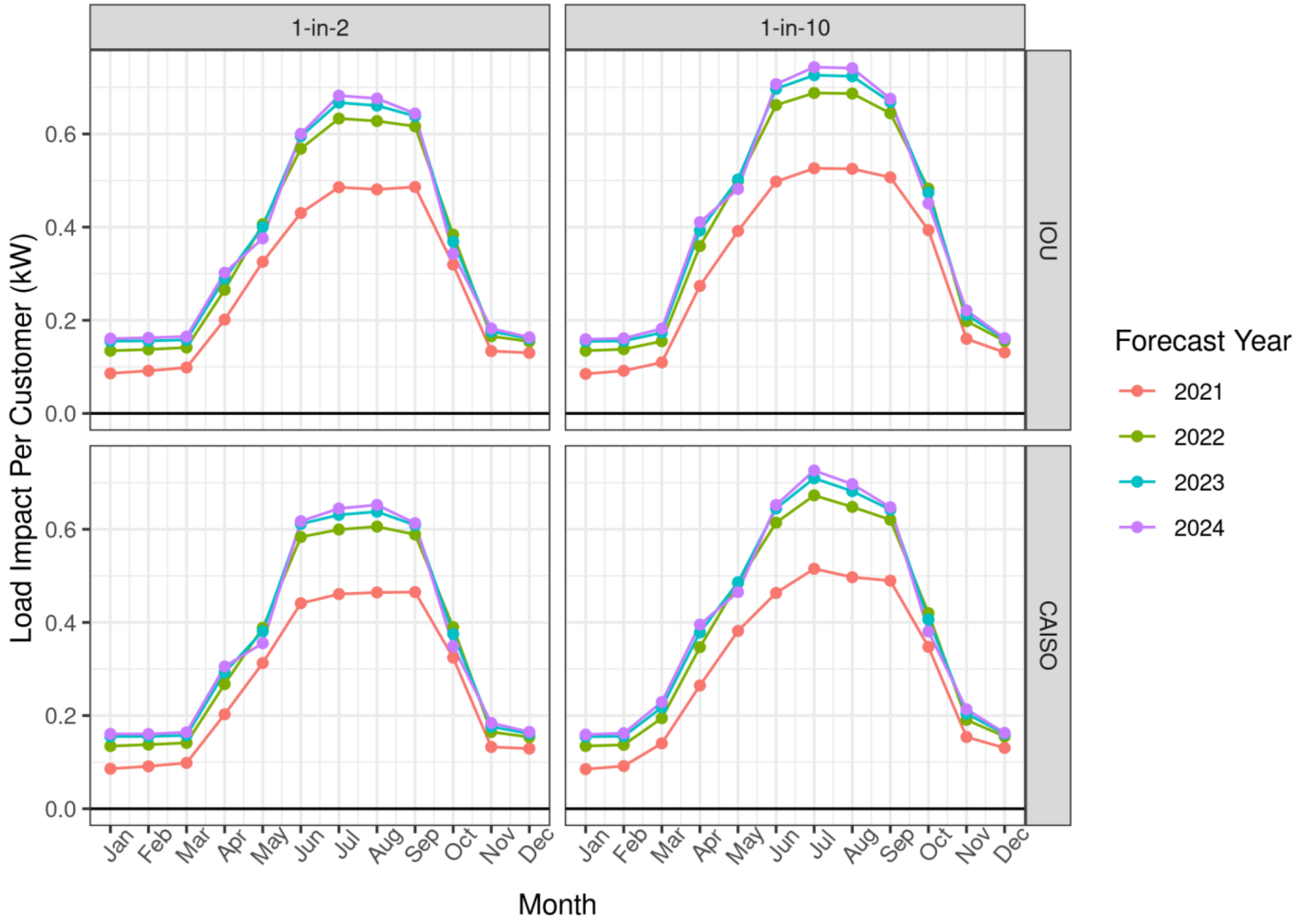


Projected fraction of device customers



Per-customer predicted monthly load impact (4-hour QC window)

- Increases primarily due to increasing fraction of device customers
- Resi-station funding requires a focus on device-owning customers

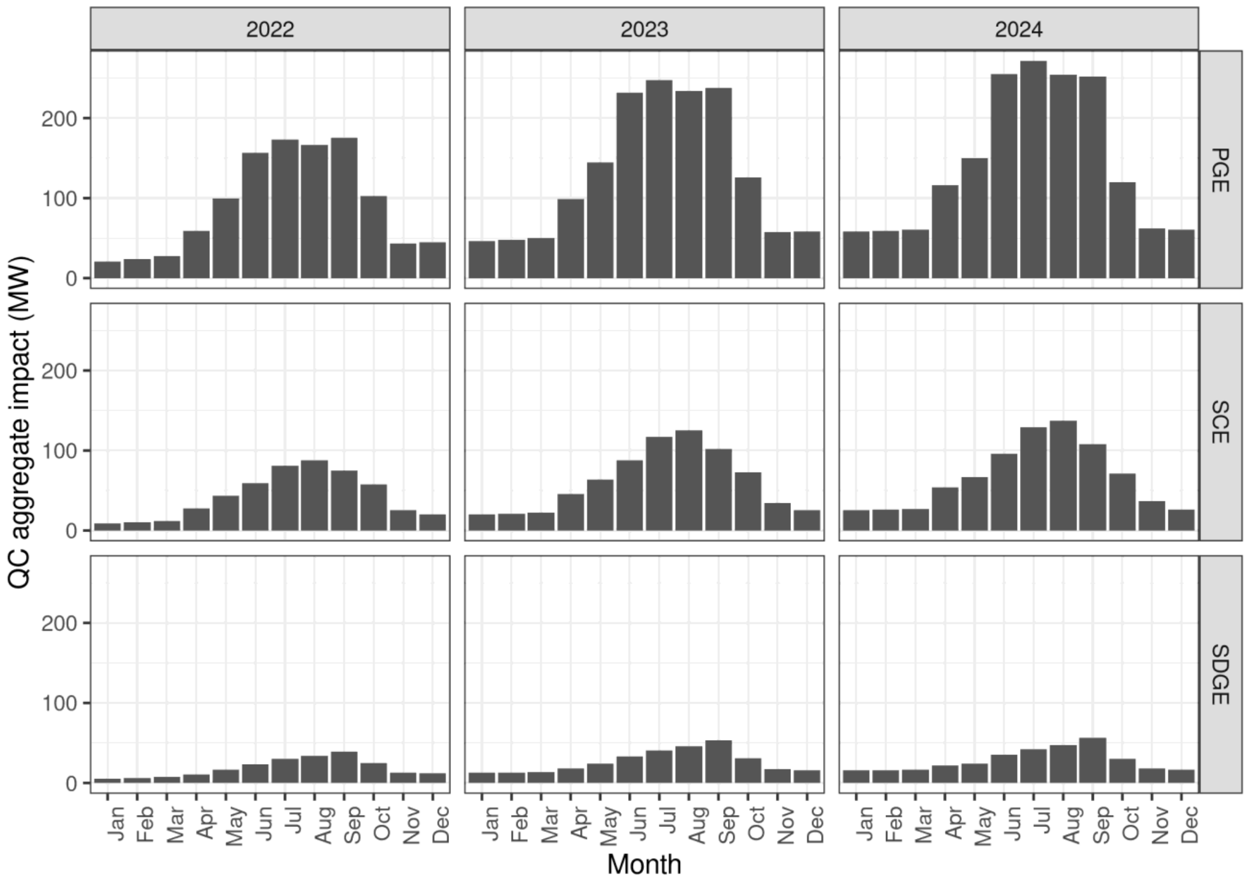


Ex post to ex ante load impact predictions, for events in hours 17-20 (2020)

	Ex post	Ex ante 2020 weather	Ex ante IOU 1-in-2 weather
January	0.05	0.06	0.05
February	0.07	0.07	0.05
March	0.06	0.06	0.05
April	0.10	0.08	0.15
May	0.13	0.10	0.22
June	0.20	0.21	0.28
July	0.20	0.22	0.34
August	0.36	0.34	0.33
September	0.19	0.19	0.34
October	0.18	0.20	0.26
November	0.07	0.08	0.08
December	0.07	0.06	0.06

Monthly IOU 1-in-2 (4-hour QC window)

Year	Temp (F)	Enrollment (August)	Aggregate Impact (MW)
2021	84.40	194,000	94.9
2022	85.44	459,000	293.6
2023	85.44	612,000	411.3
2024	85.44	648,000	444.0



Questions?

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Ex post month by month summary

		Average Event-based Data (by Month, i.e., "monthly roll-ups")								
month	ave temp (F)	# of unique events	total # participants (not unique)	average # of parts	reference load (kW)	per-part. impact (kW)	Agg. reference load (MW)	Agg. impact (MW)	# monthly unique parts.	impact %
Jan	51.9	43	335,915	7,801	0.91	0.05	7.07	0.37	104,226	5.23
Feb	57.6	41	296,360	7,218	0.83	0.06	6.02	0.44	103,323	7.36
Mar	54.6	29	197,035	6,784	0.85	0.06	5.79	0.42	101,325	7.19
Apr	63.0	35	**473,968**	13,523	0.94	0.11	12.67	1.45	102,701	11.45
May	69.	34	464,047	**13,637**	1.14	0.14	15.49	1.95	101,742	12.62
Jun	77.0	45	**550,913**	12,231	1.48	0.20	18.08	2.4	104,885	13.29
Jul	77.4	32	430,134	13,437	**1.53**	0.20	20.51	2.66	110,178	12.96
Aug	83.4	36	462,097	12,834	**1.94**	**0.35**	**24.96**	**4.44**	112,110	**17.77**
Sep	76.3	17	464,972	**27,348**	1.48	**0.21**	**40.57**	**5.73**	**115,736**	**14.11**
Oct	80.2	39	343,418	8,804	1.39	0.17	12.25	1.47	113,242	12.02
Nov	60.0	41	365,639	8,917	0.92	0.08	8.18	0.68	**113,726**	8.28
Dec	54.6	36	360,609	10,017	1.05	0.07	10.52	0.67	112,859	6.36

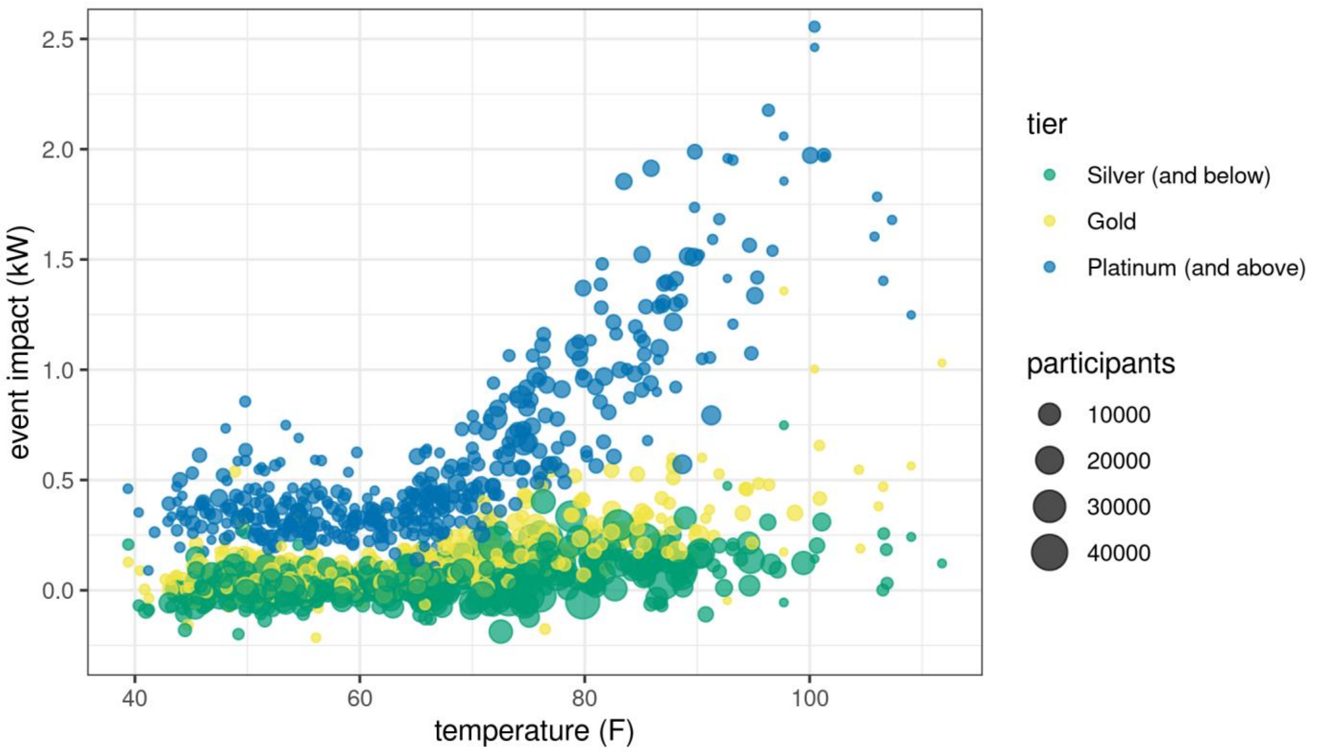
Ex ante monthly predictions (2022, IOU 1-in-2)

			Temp (F)	Impact Per Participant	Impact Per Customer	Agg Impact (MW)	Participants	Enrollment
IOU	1-in-2	Typical Event Day	84.31	0.70	0.62	286.5	410,016	459,027
		January Peak	48.67	0.15	0.14	36.27	235,675	262,648
		February Peak	52.68	0.16	0.14	41.95	263,048	296,655
		March Peak	55.04	0.16	0.15	48.27	295,666	330,663
		April Peak	73.26	0.31	0.28	100.2	320,844	364,668
		May Peak	78.51	0.47	0.42	162.9	347,725	392,408
		June Peak	81.74	0.64	0.58	242.9	377,990	420,151
		July Peak	84.62	0.71	0.65	288.8	409,186	447,898
		August Peak	85.44	0.72	0.64	293.6	410,016	459,027
		September Peak	85.43	0.69	0.63	295.0	429,526	470,159
		October Peak	78.12	0.46	0.39	189.1	411,651	481,290
		November Peak	59.67	0.19	0.17	83.96	437,595	490,356
		December Peak	48.97	0.17	0.16	79.32	461,285	499,424

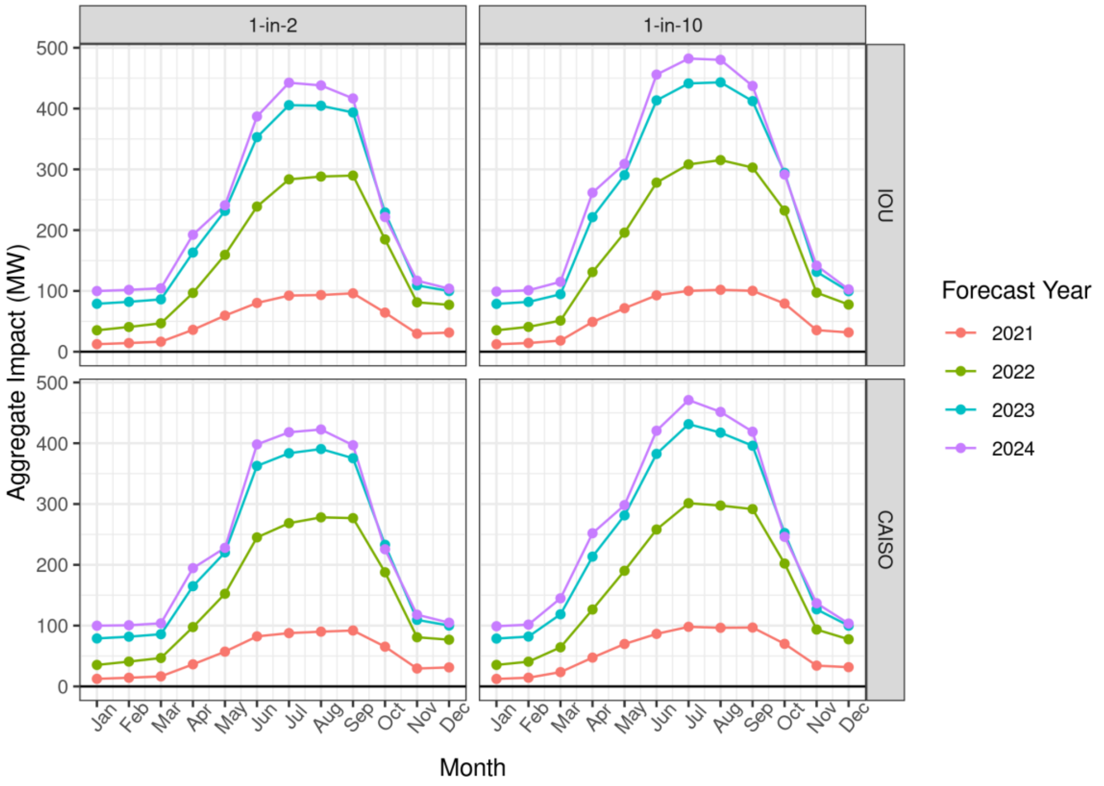
Example grid emergency performance: 8/14

date	Utility	Event hours (ending)	particip ants	Aggregate impact (MW)	Per-customer impact (kW)	Reference loads (kW)	% impact	Temp. (F)
2020-08-14	PGE	18-20	8261	5.39	0.65	3.09	21.13	101.08
2020-08-14	PGE	19-20	17757	8.96	0.50	2.95	17.10	99.43
2020-08-14	PGE	19-21	30462	9.45	0.31	1.55	20.07	90.40
2020-08-14	SCE	18-20	31212	12.27	0.39	2.41	16.37	89.75
2020-08-14	SDGE	19-21	15554	4.89	0.31	1.52	20.74	82.11

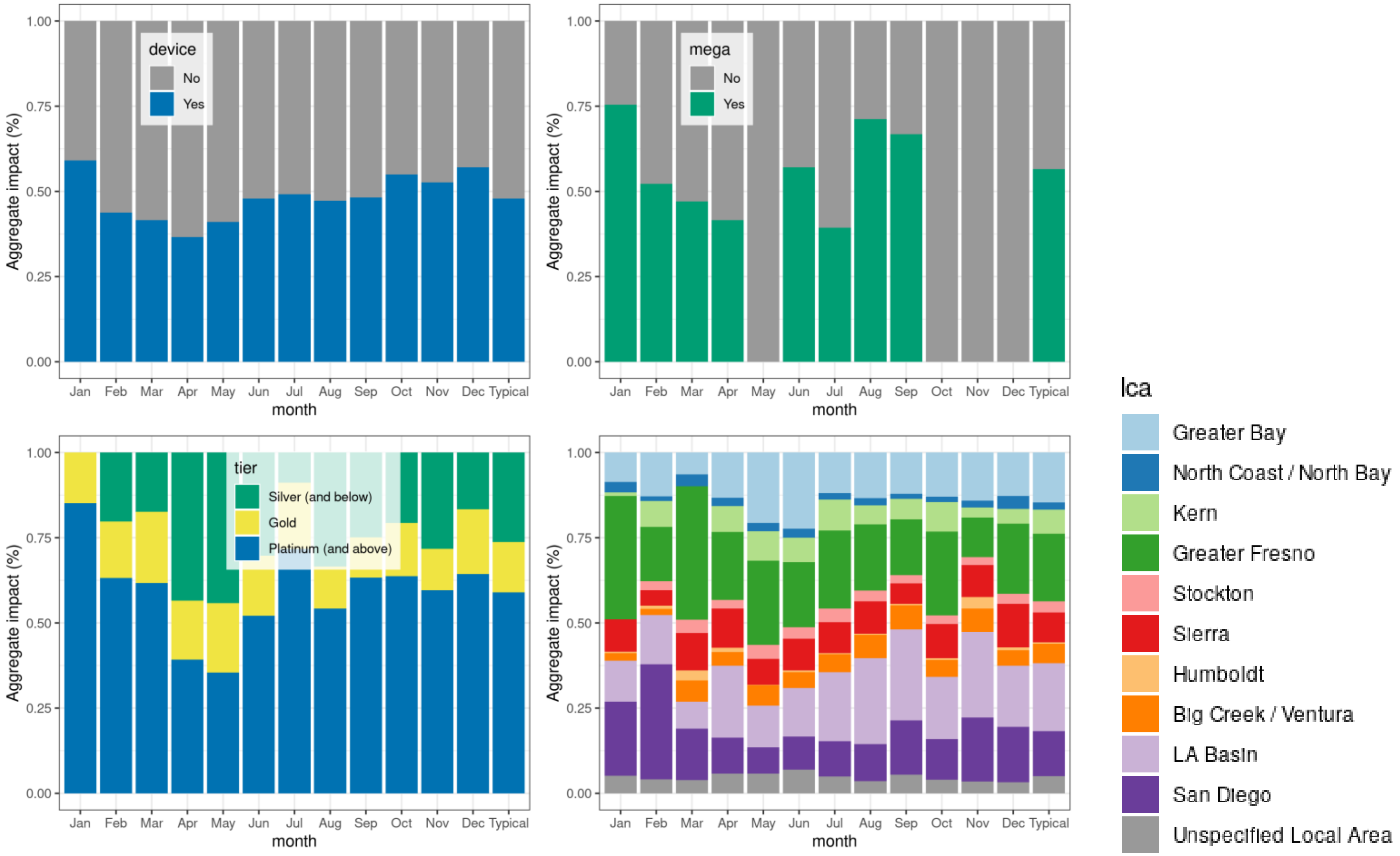
Performance by tier / temperature



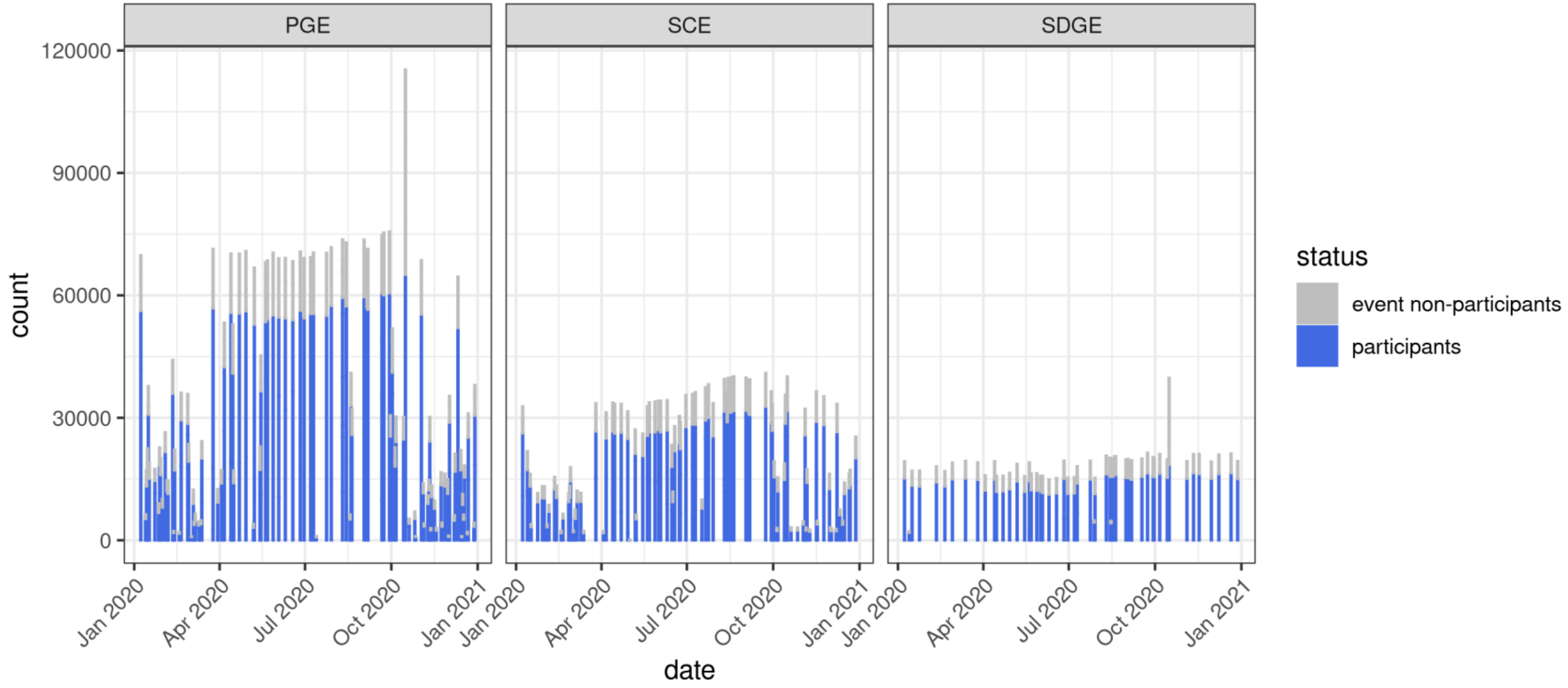
Ex ante performance by weather day



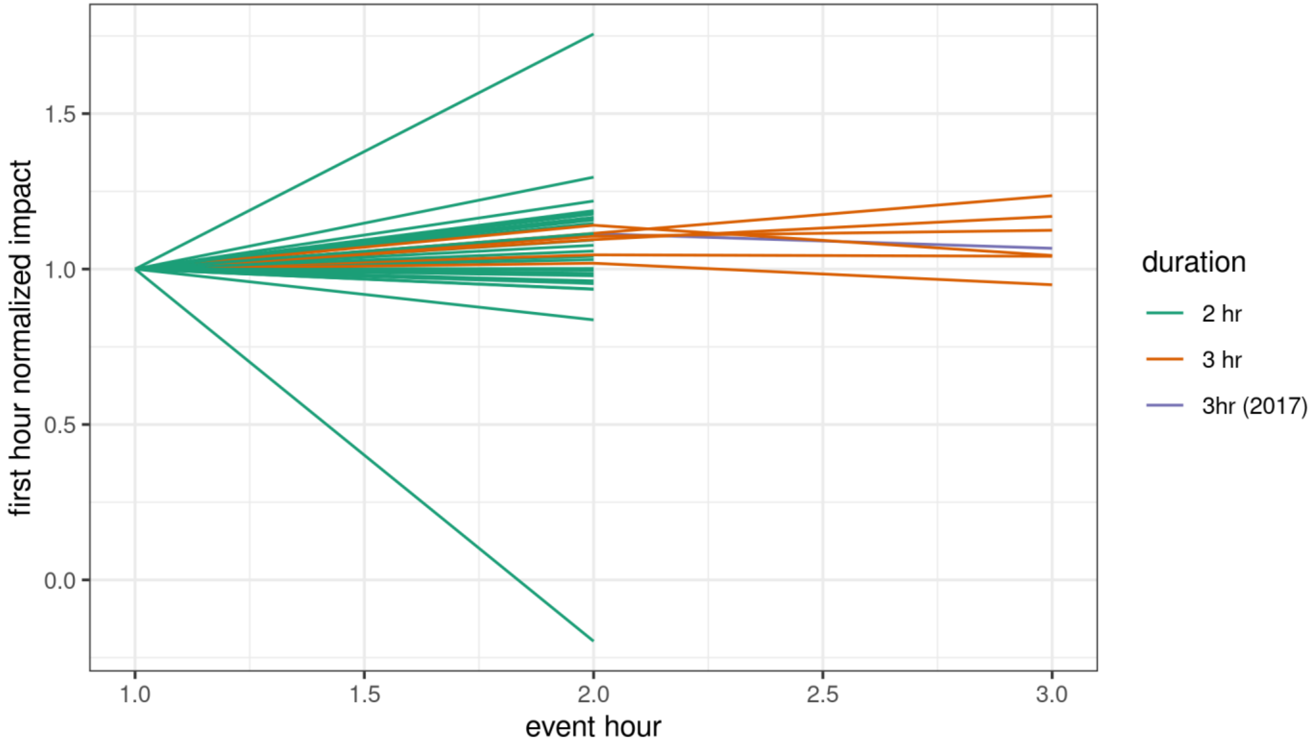
Ex post fraction of aggregate impact by device, event type, tier, and LCA



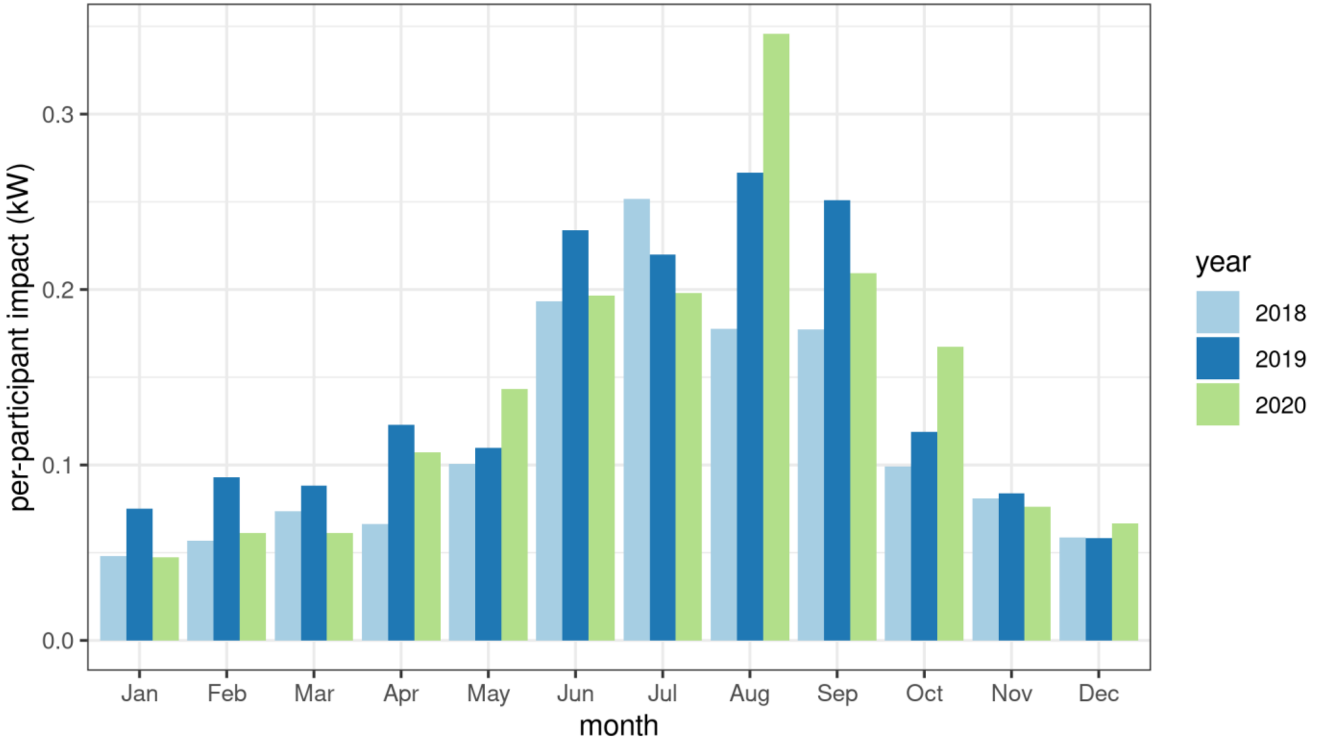
Participation rates



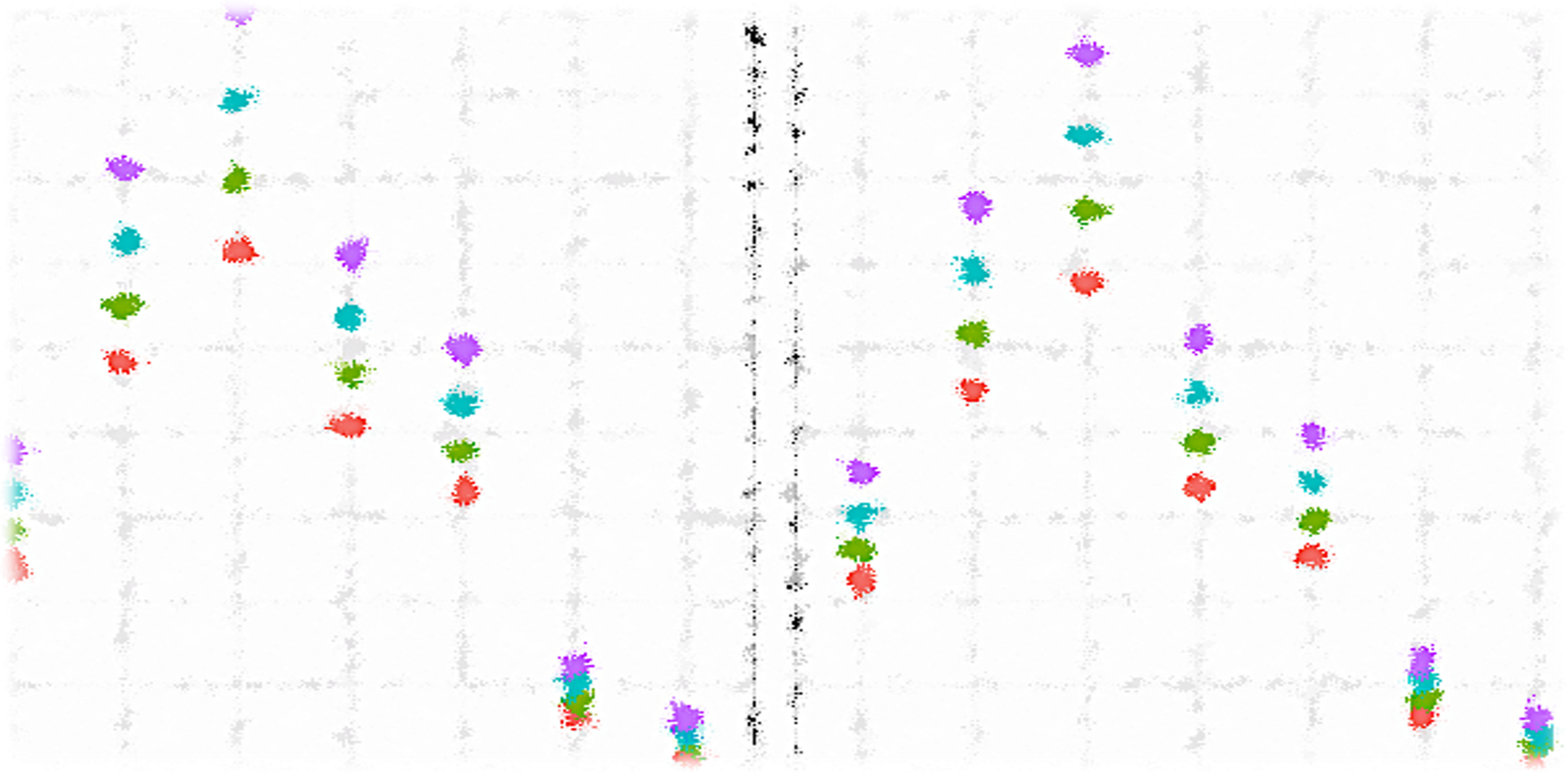
Sustained savings hour to hour



Year to year ex post monthly performance



2020 Load Impact Evaluation for CPower



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2021-05-03

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CALMAC Study ID CPR0001.01

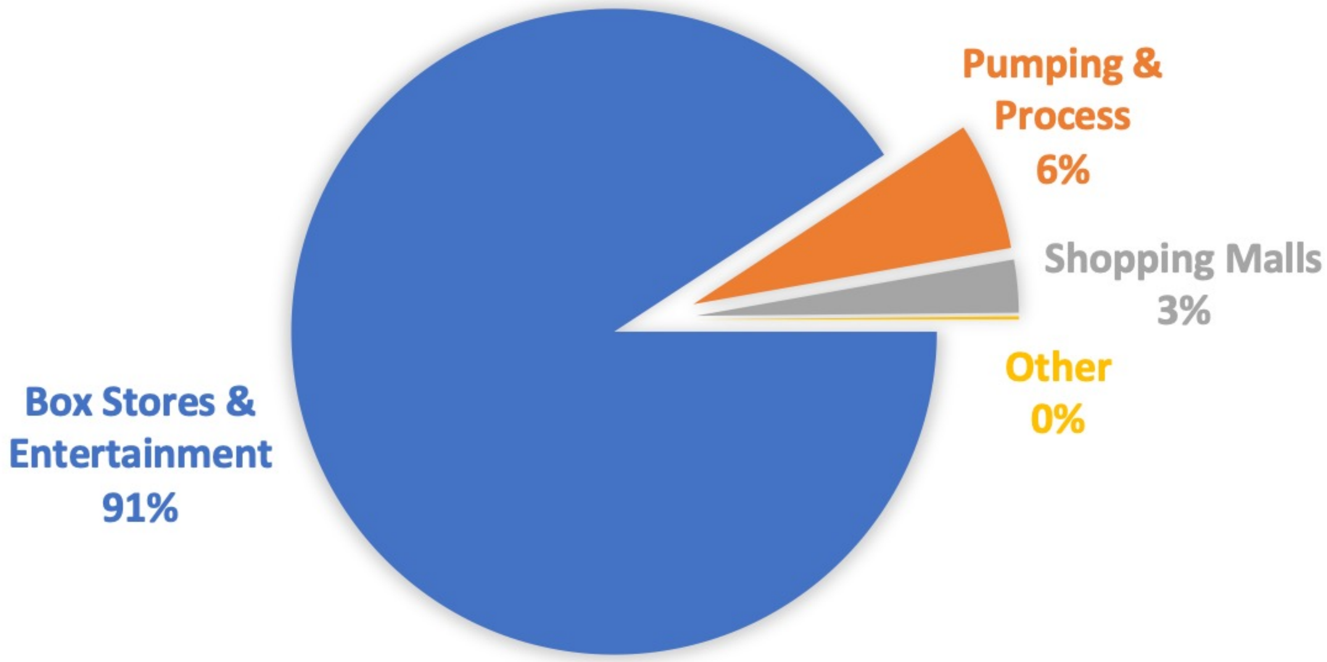
Program Background

CPower Overview

- Customers are from a variety of sectors
  - Commercial
  - Industrial
  - Agricultural
  - Government
- CPower works with their clients on all demand-side energy management goals, including DR
- CPower has over 1,700 customers and 11,000 sites in the US. 162 customers and 1950 sites are in this evaluation
- Customers have historically participated in CBP and DRAM, CPower will be transitioning the resource to be available as QC

CPower Customers in CA

- Most sites are box stores and entertainment
- Nonresidential customers from many sectors, including agricultural, industrial, and commercial



End of 2020 Enrollment

- Customers spread throughout much of California
- Most sites have demand <100 kW with a few much larger

IOU	Local Capacity Area	Customers	Sites
PGE	Greater Bay	19	315
PGE	Greater Fresno	15	161
PGE	Humboldt	<10	<15
PGE	Kern	11	51
PGE	North Coast / North Bay	13	82
PGE	Sierra	10	79
PGE	Stockton	11	38
PGE	Unspecified Local Area	15	205
SCE	Big Creek / Ventura	16	177
SCE	LA Basin	20	586
SCE	Unspecified Local Area	10	42
SDGE	San Diego	17	206

Events and Dispatch

- Each event covered a subset of customers, no full resource events
- There were 92 events in 2020 with durations ranging from 1 to 4 hours and start times from 4 PM to 8 PM
- Events are a mix of market dispatch and test

Month	Number of Events	Average Number of Sites per Event
Jun	6	412
Jul	12	311
Aug	28	293
Sep	15	323
Oct	20	339
Nov	5	254
Dec	6	287

Ex Post Results

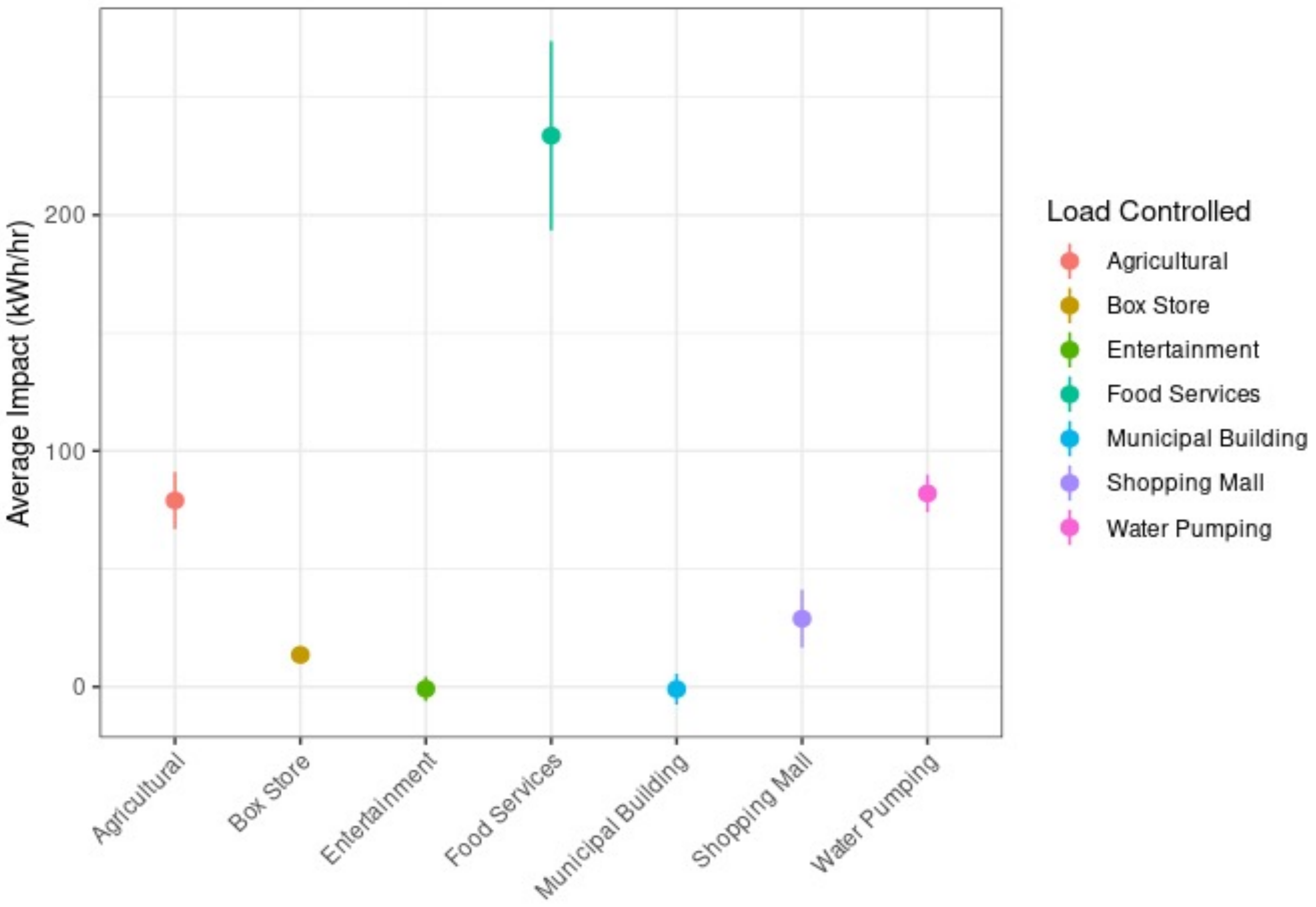
Data and Methods

- 2018 through 2020 historical customer enrollment, events and hourly electricity usage
- Estimated impacts for all events using a variety of models
- Selected the model with lowest bias and variance across events, customer types and temperature
  - CAISO 10-of-10 with same-day adjustment

Ex Post Results

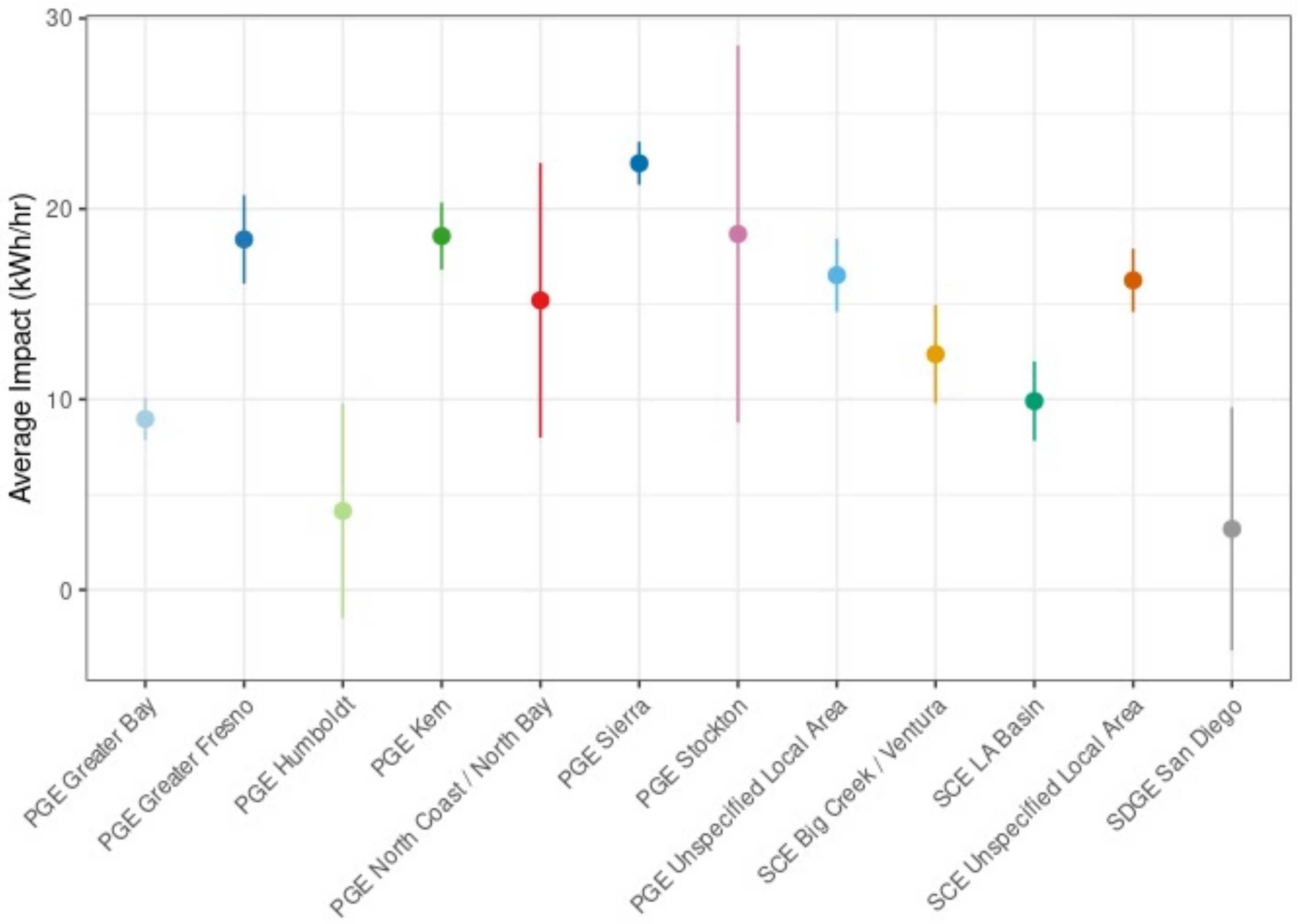
Month	# of events	Average # of sites	Average temperature (F)	Average baseline (kW)	Average impact (kW)	Load impact %
Jun	6	91	80	47	2	5
Jul	12	82	82	81	11	13
Aug	28	66	88	105	16	15
Sep	15	75	81	85	11	14
Oct	20	75	85	99	14	14
Nov	5	64	78	67	6	9
Dec	6	64	67	56	4	7

Ex Post Results by Customer Type



Vertical lines show 90% CIs

Ex Post Results by LCA



Vertical lines show 90% CIs

2020 Grid Emergency Ex Post Results

Date	Mean Event Temperature (F)	Mean Impact (kW)	Mean Baseline (kW)	Percent Impact	Participant Count	Total Impact (MW)	Std.Err. (MW)	90% Confidence Interval (MW)
2020-08-14	93.0	9.1	98.5	9	890	8.1	4.5	(0.7, 15.4)
2020-08-17	86.4	13.1	101.5	13	655	8.6	3.0	(3.6, 13.6)
2020-08-18	91.1	12.2	124.9	10	343	4.2	2.1	(0.8, 7.6)
2020-08-19	84.4	23.8	118.1	20	870	20.7	5.7	(11.3, 30.2)

Covid Effects

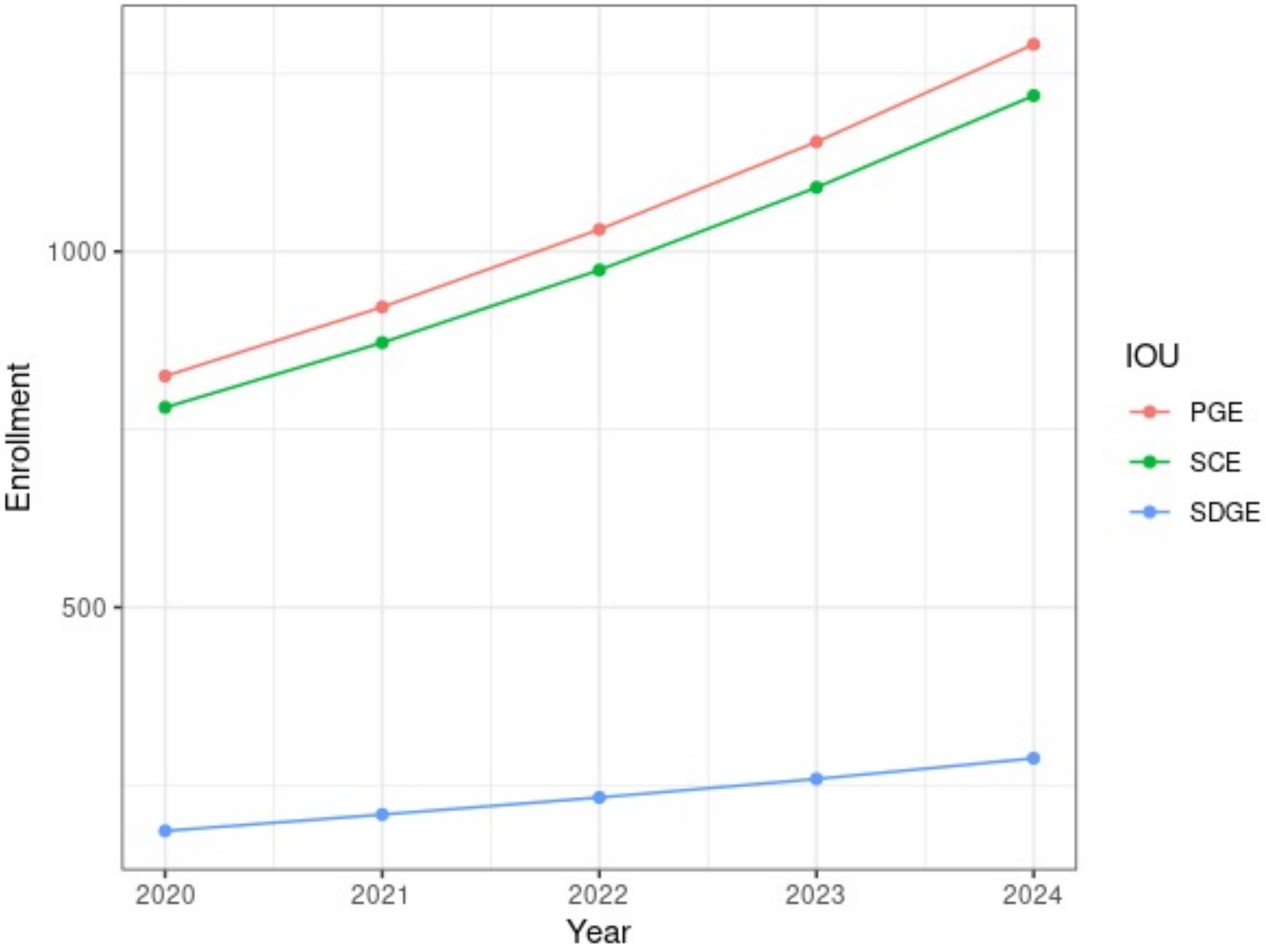
- Year-over-year variation in impacts is larger than covid effects
- Enrollment changes across years further obscure any covid effects
- True covid effects for different customers types are likely in different directions
- No comparison group is available

Ex Ante Results

Data and Methods

- Full year’s interval data for 2020
- Used regression models on groupings of customers to estimate event and non-event hour loads
- Predicted with 1-in-2 and 1-in-10 weather
- Applied to enrollment forecast

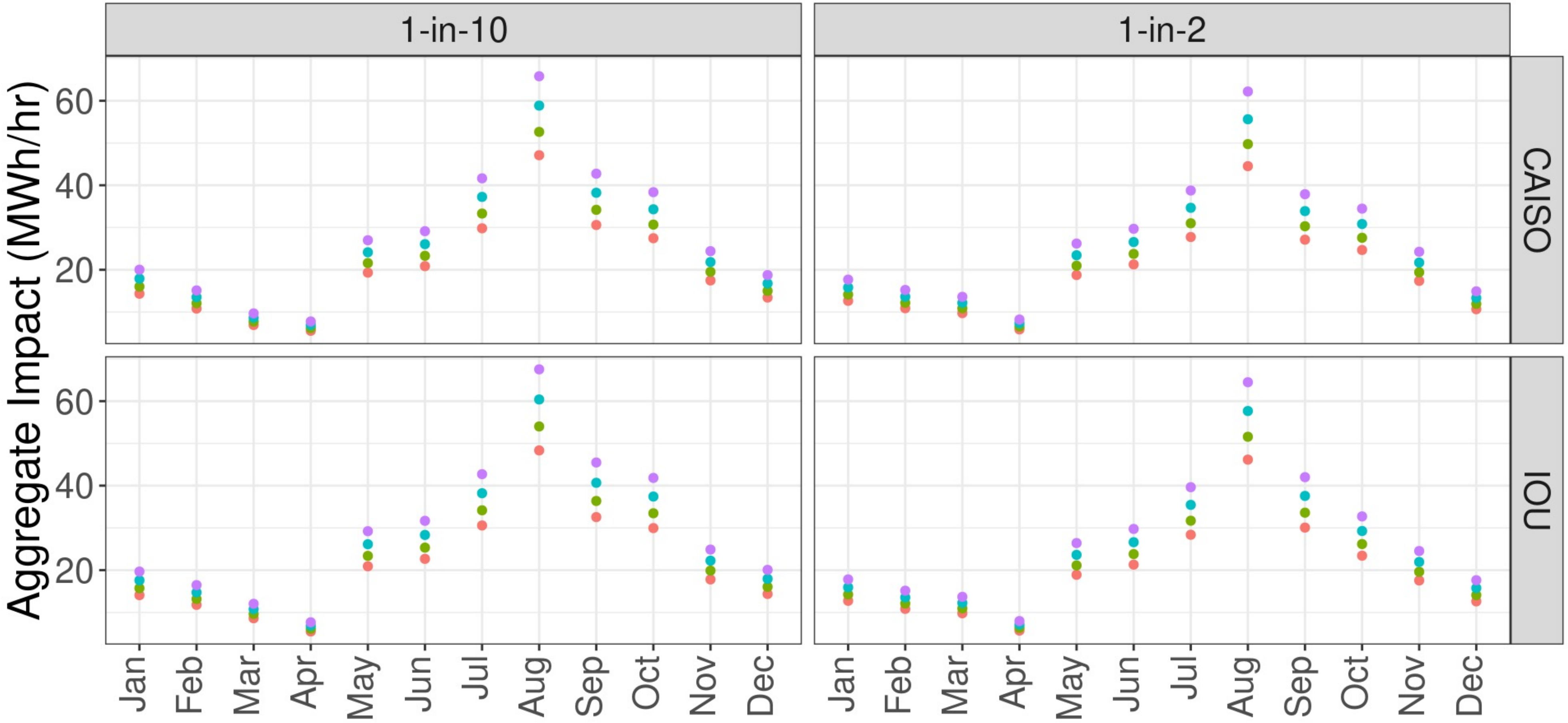
Medium Enrollment Forecast



Ex Ante Impact Prediction

Year	Medium Forecast Enrollment	CAISO 1-in-2 day		IOU 1-in-2 day	
		Temp (F)	Aggregate Impact (MW)	Temp (F)	Aggregate Impact (MW)
2021	2003	86	44.5	88	46.1
2022	2238	86	49.7	88	51.6
2023	2503	86	55.6	88	57.7
2024	2798	86	62.2	88	64.5

Ex Ante for 2021 – 2024



Conclusion

Recommendations for the Future

- Call a representative sample of long-duration events to provide statistical support for the full-resource events needed for Qualifying Capacity.
- Consider dispatching a subset of future events with true randomized controls.
- Revisit how best to apply LIPs to new and rapidly growing third party market entrants. Notably “Typical Events” in the table-generators

Questions and Discussion

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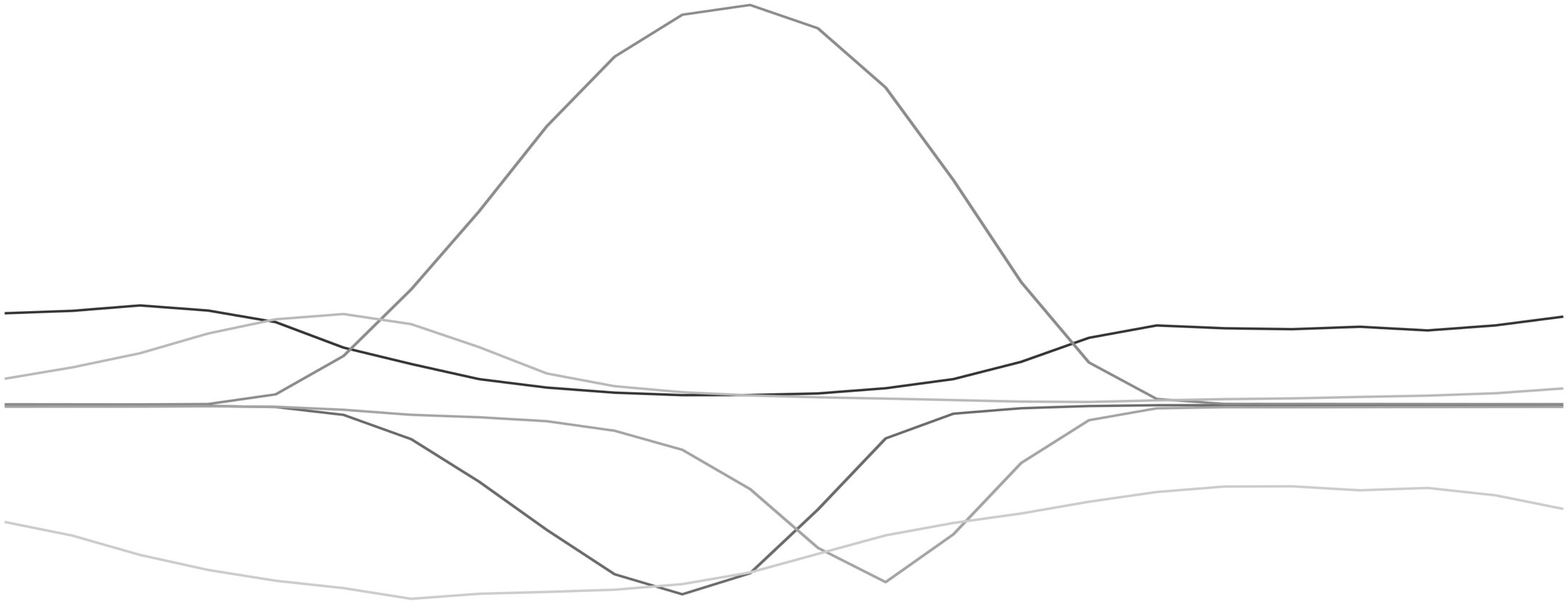
2020 Load Impact Evaluation for Leapfrog Power



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2021-05-03

GROUNDED ANALYTICS

Convergence Data Analytics

Co-authors:
Phil Price
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Mary Sutter

CALMAC Study ID LPF0002.01

Program Background

Leap Overview

- Leap provides a marketplace for grid flexibility where DER providers can make connected loads available as grid resources
- Leap has thousands of unique customer locations registered and trading energy in CAISO wholesale market. Diverse mix of residential, commercial, and agricultural
- Became a CAISO Scheduling Coordinator and began participating in CAISO markets as Demand Response Provider in 2019
- Leap has won capacity in multiple DRAM auctions and delivered Resource Adequacy (RA) to PG&E and SCE (2019 – 2021) and SDG&E (2020 – 2021)
- Leap's marketplace allows resources to bid into the CAISO market based on their opportunity cost, receive and respond to market awards, and be compensated for their performance

Customers

- Diverse customer base
- Nonresidential customers from many sectors, including agricultural, industrial, and commercial
- Residential customers are primarily controlling AC loads
- Leap is expanding into residential solar + storage

Load Type	Customer Type	Customers	Meters
Cold Storage	Non-Residential	<15	<15
HVAC	Non-Residential	31	474
Large Battery Storage	Non-Residential	<15	<15
Manufacturing / Process	Non-Residential	<15	<15
Other	Non-Residential	<15	16
Pumping	Non-Residential	24	264
Res AC	Residential	8059	8399
Res Battery	Residential	107	108

End of 2020 Enrollment

- Customers spread throughout much of California
- Enrollment grew substantially during 2020

Utility	Nonresidential Customers	Nonresidential Meters	Residential Customers	Residential Meters
PG&E	31	326	8087	8427
SCE	32	520	<100	<100
SDG&E	<15	60	0	0
Municipal Utilities	<15	<15	<100	<100

Events and Dispatch

- Each event covered a subset of customers, no full resource events
- There were 93 events with durations ranging from 1 to 4 hours and start times from 4 PM to 8 PM
- Events are a combination of market, test, and emergency
- Nearly all customers are dispatched automatically

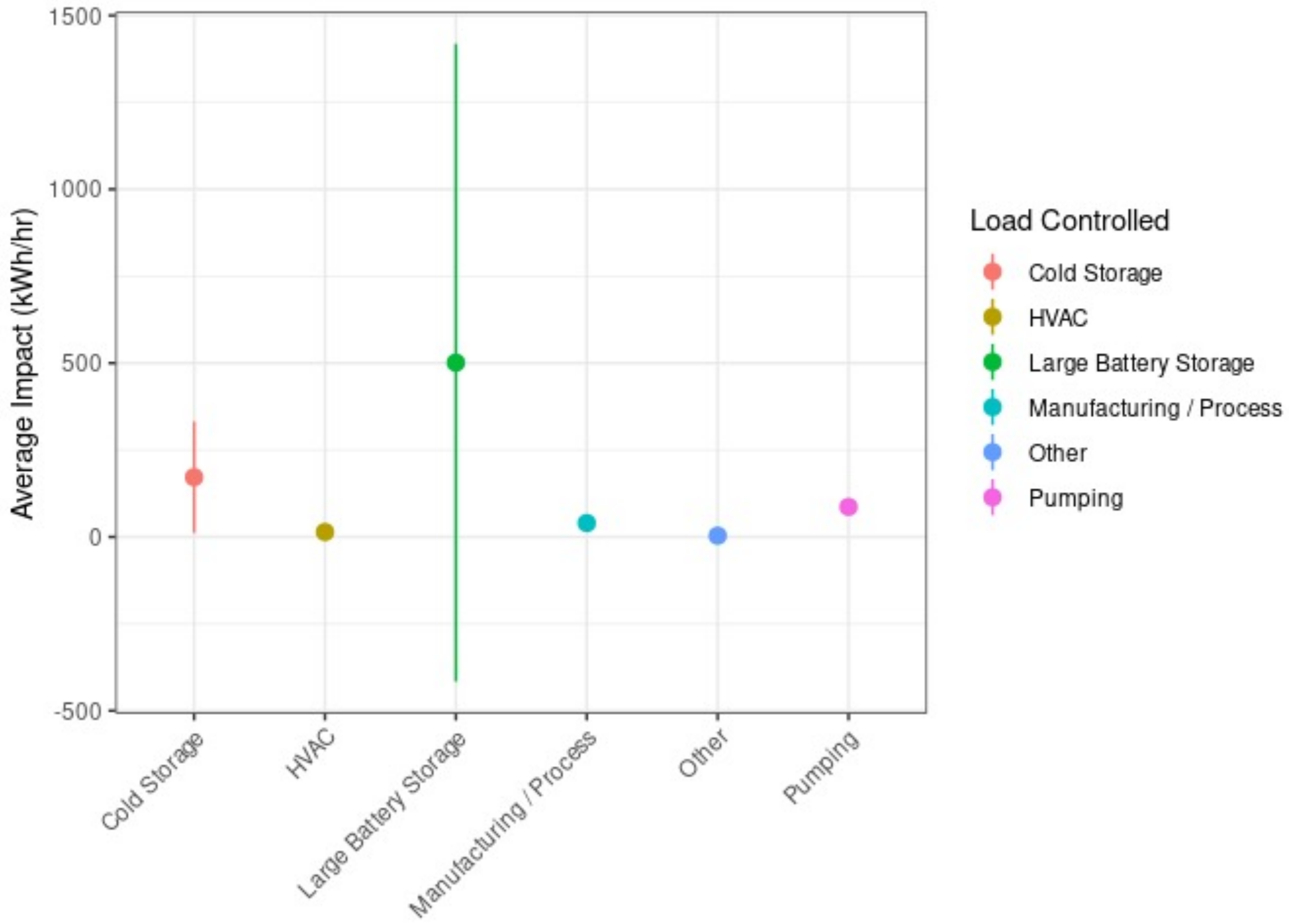
Sector	Month	Event Count	Mean Participant Meter Count
Non-residential	July	10	34
	August	21	64
	September	11	55
	October	8	58
Residential	July	13	1013
	August	12	2367
	September	6	3260
	October	12	2222

Ex Post Results

Combined Ex Post Results

Sector	Month	Event Count	Mean Participant Count	Mean Temperature (F)	Mean Baseline (kW)	Mean Impact (kW)	Percent Impact (%)
Non-Residential	July	10	34	95	209	72	35
	August	21	64	92	178	52	29
	September	11	55	93	145	38	26
	October	8	58	93	109	36	34
Residential	July	13	1013	82	1.30	0.30	23
	August	12	2367	92	2.40	0.51	21
	September	6	3260	86	1.99	0.56	28
	October	12	2222	82	1.34	0.26	19

Nonresidential Ex Post Results by Load Type



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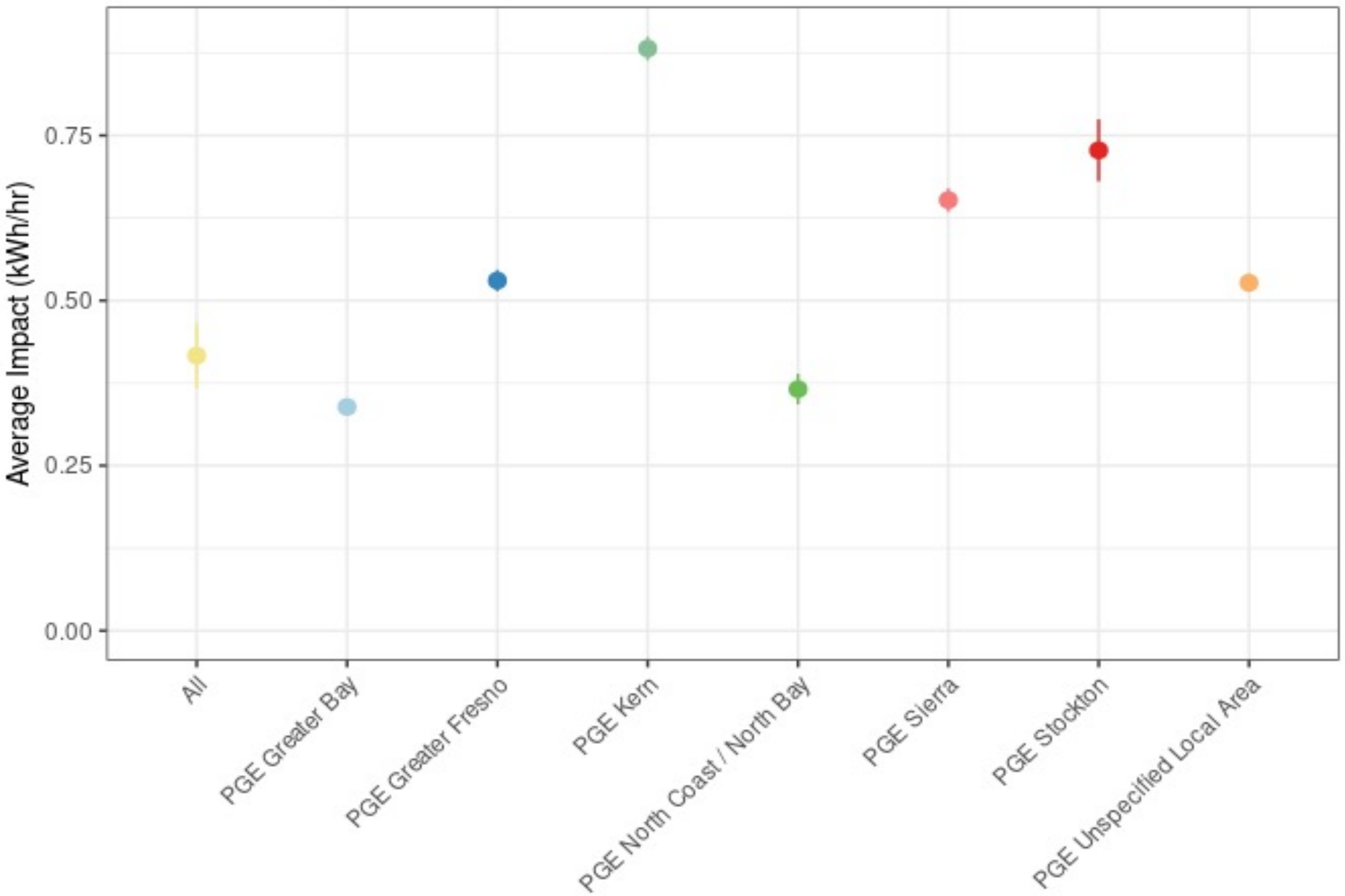
Residential Ex Post Results by LCA



Vertical lines show 90% CIs

2020 Grid Emergency Ex Post Results

Customer Type	Event Date	Mean Event Temperature (F)	Mean Impact (kW)	Mean Baseline (kW)	Percent Impact	Participant Count	Total Impact (MW)	Std.Err. (MW)	90% Confidence Interval (MW)
Non-Residential	2020-08-14	88.2	41.0	504.6	8	11	0.5	1.3	(-1.8, 2.7)
	2020-08-17	95.3	51.8	161.0	32	379	19.6	5.3	(11.0, 28.3)
	2020-08-18	93.2	53.1	200.0	27	446	23.7	10.8	(6.0, 41.4)
	2020-08-19	90.7	55.3	156.3	35	446	24.6	12.1	(4.7, 44.6)
	2020-09-07	86.2	39.5	108.1	37	168	6.6	4.6	(-1.0, 14.3)
Residential	2020-08-14	97.9	0.6	2.8	22	6534	4.1	0.1	(3.9, 4.3)
	2020-08-17	69.0	0.0	0.8	-6	177	0.0	0.0	(-0.0, -0.0)
	2020-08-18	94.2	0.8	2.7	30	6728	5.5	0.1	(5.2, 5.7)
	2020-08-19	88.9	0.6	2.2	29	6728	4.2	0.1	(4.0, 4.4)
	2020-09-07	93.5	0.8	2.9	28	6740	5.6	0.1	(5.4, 5.8)

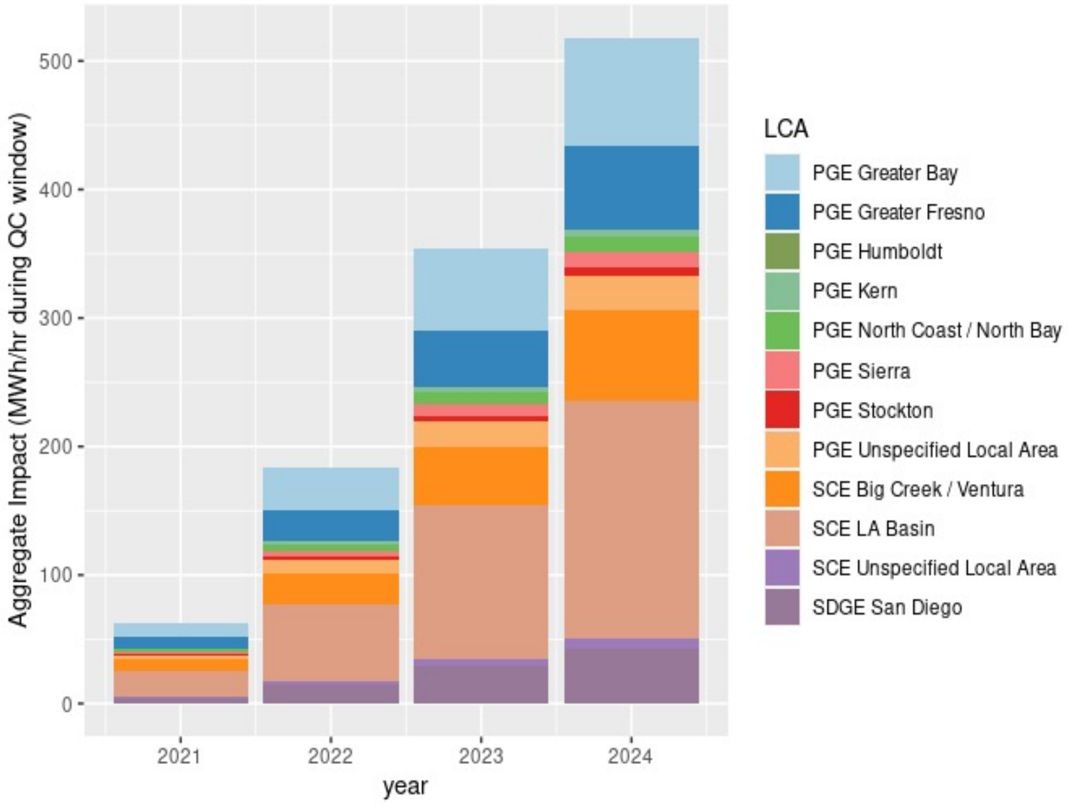
Impacts exceeded market awards for all emergency events

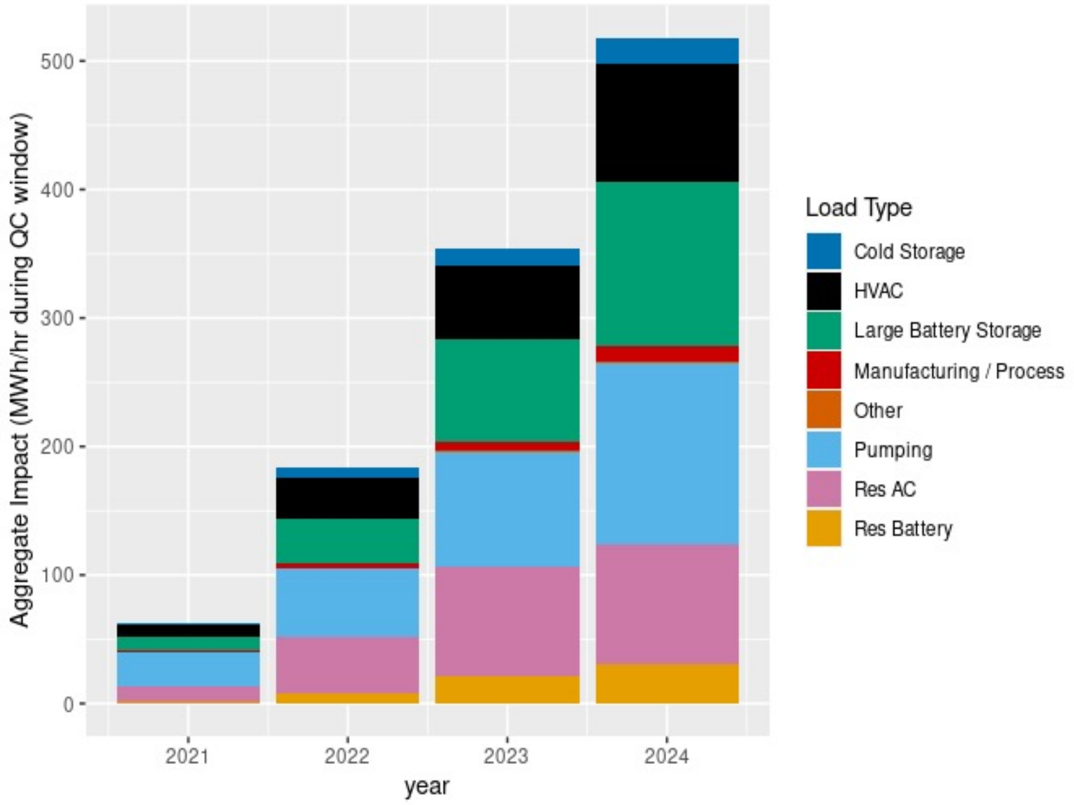
Covid Effects

- Year-over-year baseline comparisons show no pattern so estimates of covid effects would be highly uncertain
- Load categorization and enrollment changes between 2019 and 2020 further obscure any covid effects
- True covid effects for different load types are likely in different directions
- No comparison group is available

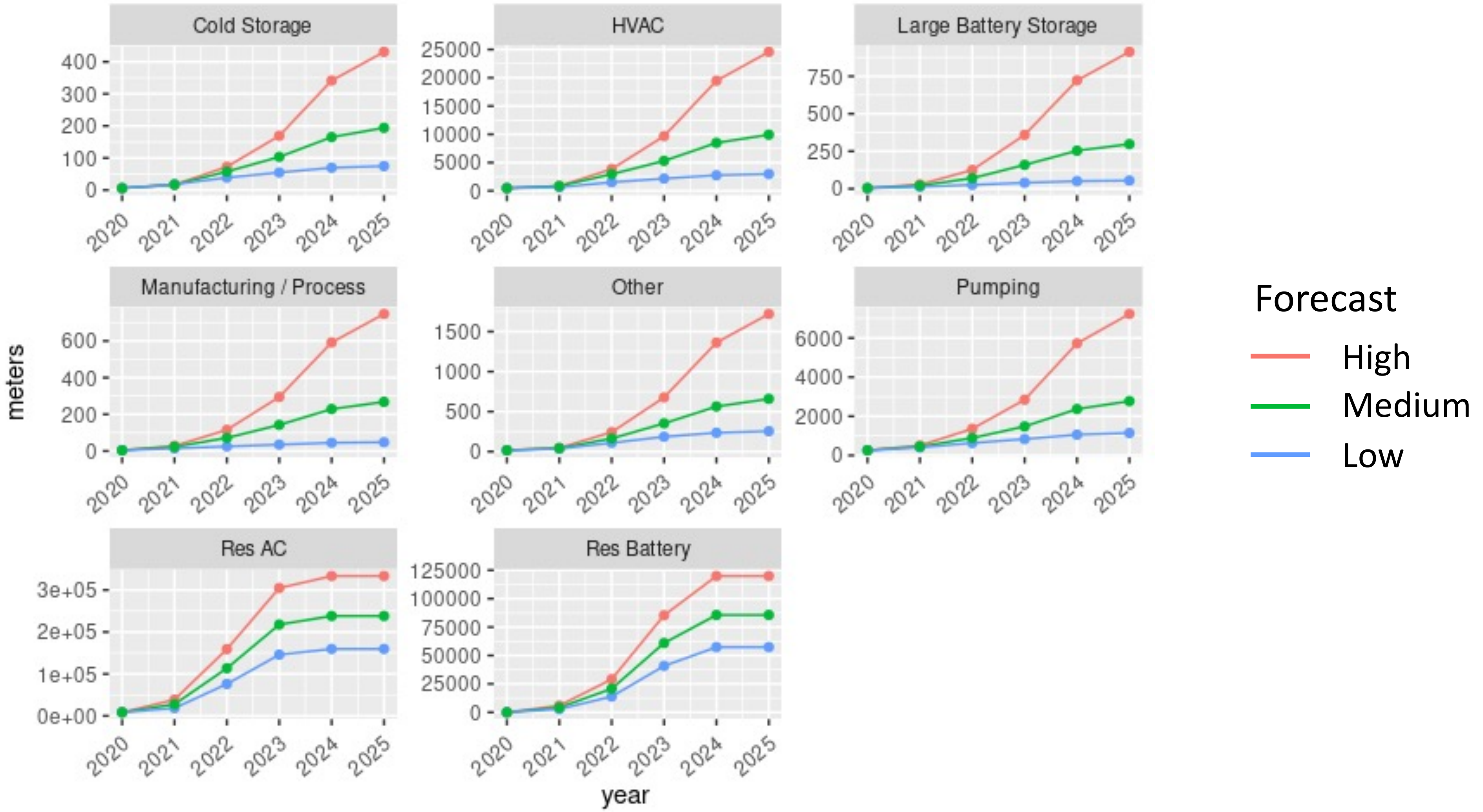
Ex Ante Results

Impact Forecast

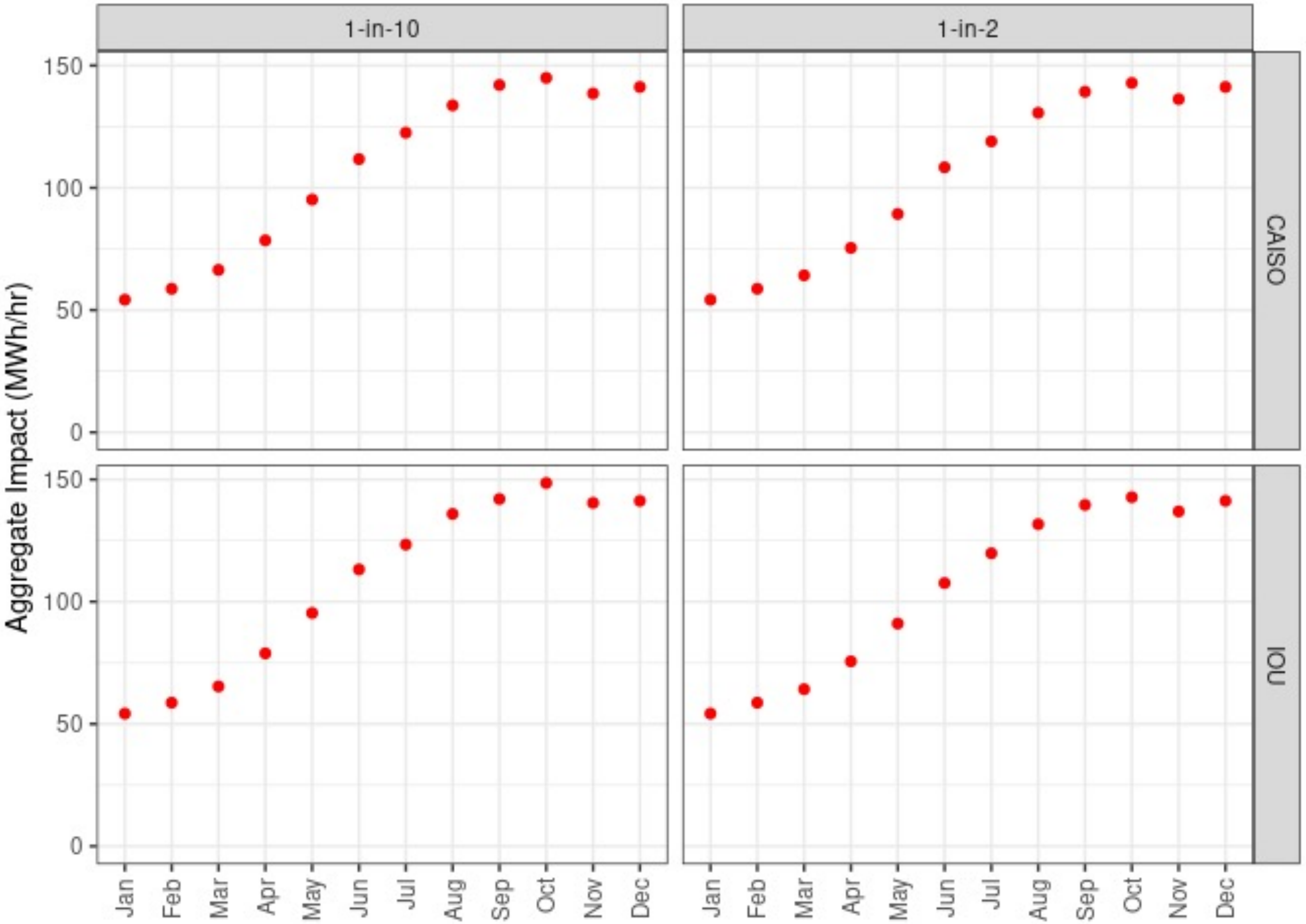




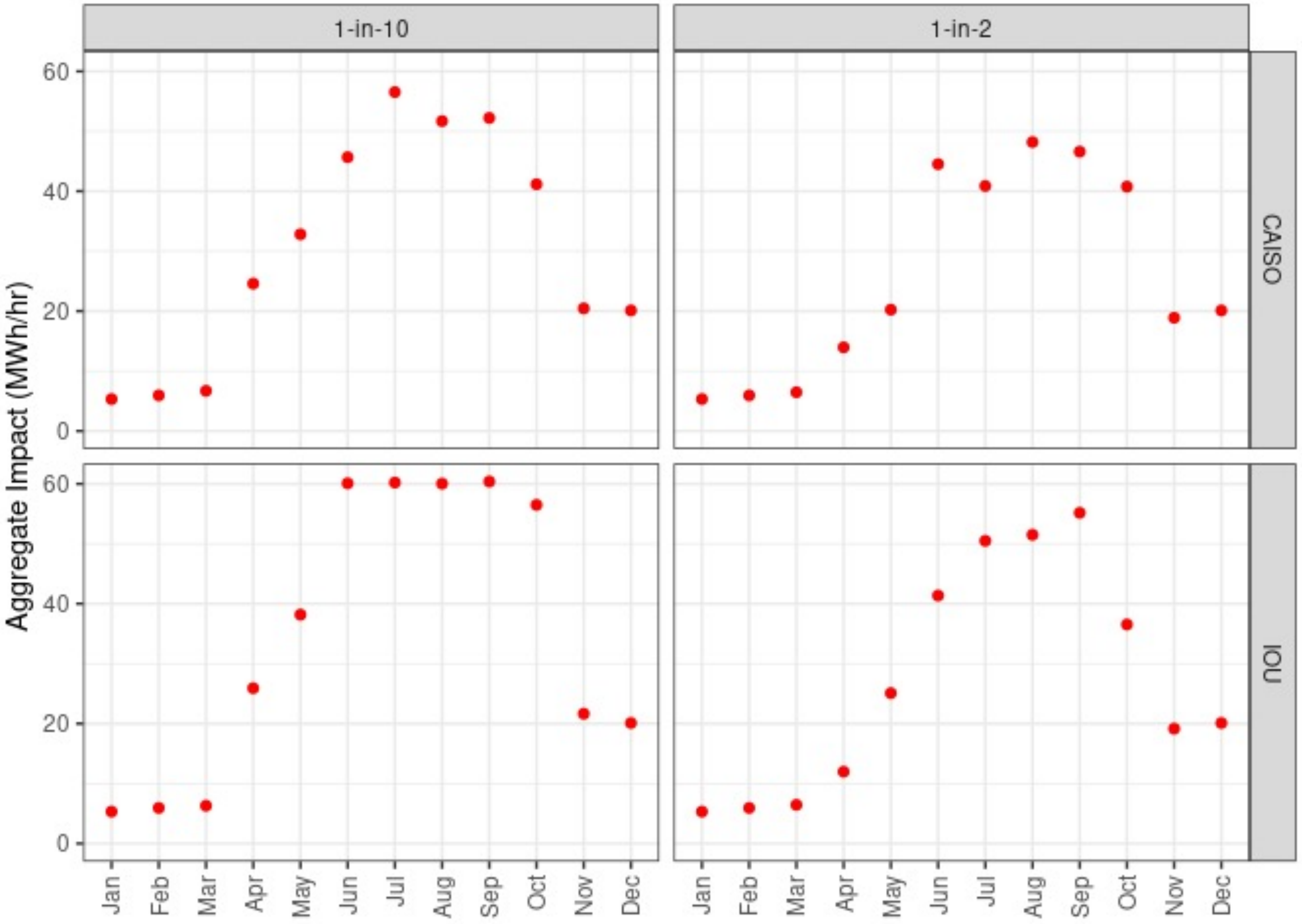
Enrollment Forecast



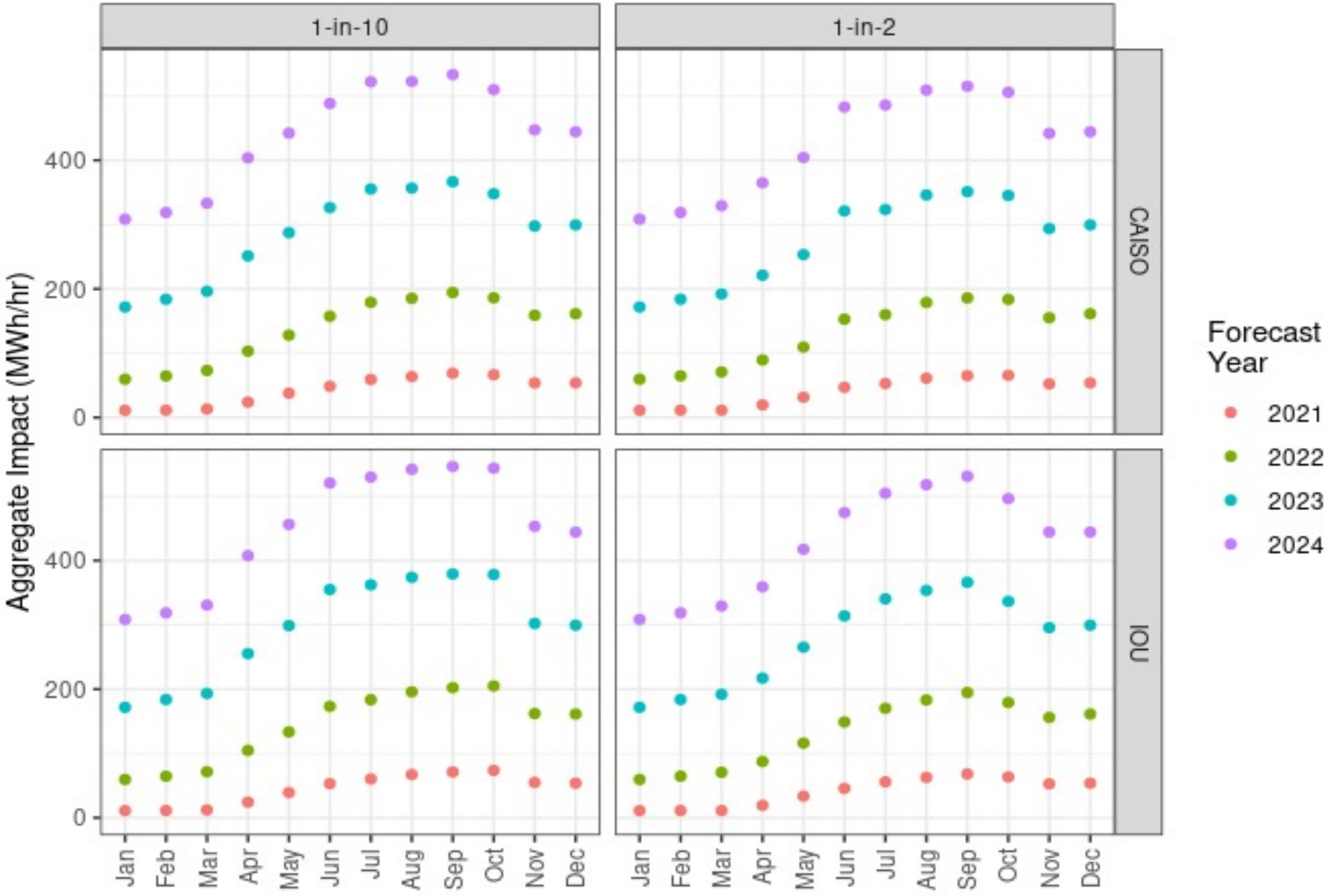
Nonresidential 2022 Ex Ante Results



Residential 2022 Ex Ante Results



Combined Ex Ante for 2021 – 2024



Recommendations for the Future

- Continue to call longer-duration events that provide statistical support for 4-hour+ RA window events that Qualifying Capacity numbers are based upon
- Call events during more months of the year to gather information about seasonality and weather influences on event impacts
- Revisit how best to apply LIPs to new and rapidly growing third party market entrants. Notably “Typical Events” in the table-generators

Comparison of 2020 to 2019 Ex Post

Load Type	2020 Ex Post load impact per meter	2019 Ex Post load impact per meter
Cold Storage	171.7	-
HVAC	14.1	14.2
Large Commercial Battery	501.3	47.9
Manufacturing / Process	39.9	-
Other	3.5	-
Other & Thermal Storage	-	76.0
Pumping	86.3	35.5
Residential Airconditioning	0.4	0.6
Residential Battery	0.5	0.5

Questions and Discussion

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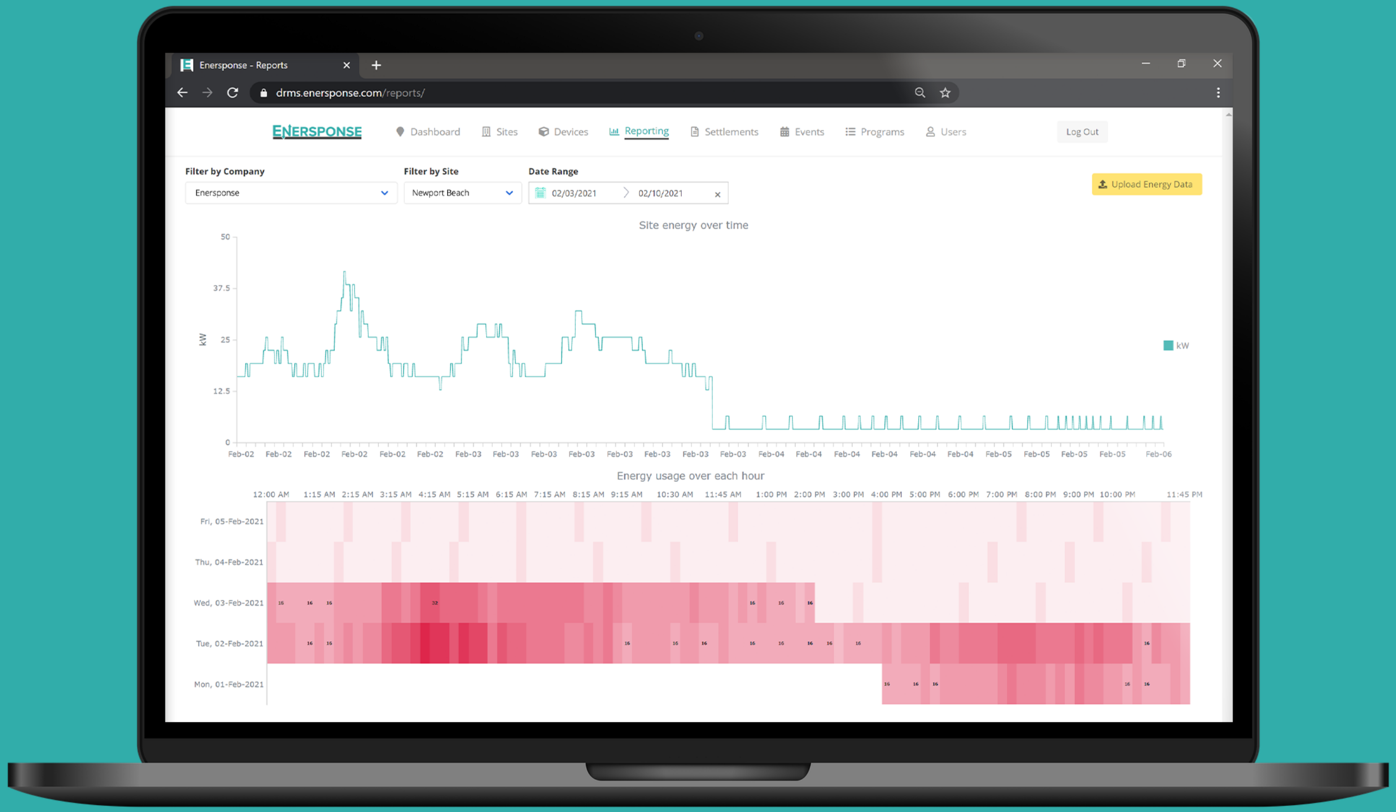
GROUNDED ANALYTICS

Convergence Data Analytics

ENERSPONSE

Hanna NRG, LLC

Load Impact Protocols Workshop



PROGRAM BACKGROUND

About ENERSPONSE

Enersponse is a Demand Response Aggregator, and Auto-DR Integrator, managing nearly 5,000 commercial, industrial, agricultural and municipal water pumping locations actively participating in Demand Response programs across North America.

Enersponse manages customer participation by way of their Demand Response Automation System, connecting to end-use customer controls via a library of software integrations, including custom API's and OpenADR.

While some Enersponse customers are dispatched using traditional methods (email & sms/text notifications) most of their resources are direct-control.

Enersponse has been actively participating in various California Demand Response programs since 2015. The customer accounts included in this report have been actively managed by Enersponse in California demand response programs during program years 2019 and 2020.

EVENTS & DISPATCH

Event Day	Event Start	Event End	# of Accts
30 May 2019	4:00 PM	6:00 PM	201
20 Jun 2019	4:00 PM	6:00 PM	201
26 Jun 2019	4:00 PM	6:00 PM	201
22 Aug 2019	4:00 PM	6:00 PM	201
31 Jul 2020	4:00 PM	6:00 PM	174
14 Aug 2020	5:00 PM	7:00 PM	89
17 Aug 2020	5:00 PM	8:00 PM	263
18 Aug 2020	4:00 PM	8:00 PM	263
19 Aug 2020	6:00 PM	8:00 PM	263
20 Aug 2020	4:00 PM	6:00 PM	89
29 Sep 2020	4:00 PM	6:00 PM	174
02 Oct 2020	4:00 PM	6:00 PM	162

SOURCE: ENERSPONSE

EVENT PARTICIPATION BY LOAD TYPE

Event	HVAC	Pumping	Total
30 May 2019	97	104	201
20 Jun 2019	97	104	201
26 Jun 2019	97	104	201
22 Aug 2019	97	104	201
31 Jul 2020	122	52	174
14 Aug 2020	7	82	89
17 Aug 2020	129	134	263
18 Aug 2020	129	134	263
19 Aug 2020	129	134	263
20 Aug 2020	7	82	89
29 Sep 2020	122	52	174
02 Oct 2020	122	104	162

EX-POST RESULTS

EX-POST METHODOLOGY

Enersponse has elected to use performance results from its clients in California that have participated in program years 2019-2020.

For the ex-post analysis, baseline loads were estimated using individual regression modeling. Different model configurations were tested for accuracy and bias to determine the best fit. Once the consumer baselines were calculated, the consumer load impacts were calculated by subtracting the baseline loads in each hour from the consumer's actual load in that hour during the event.

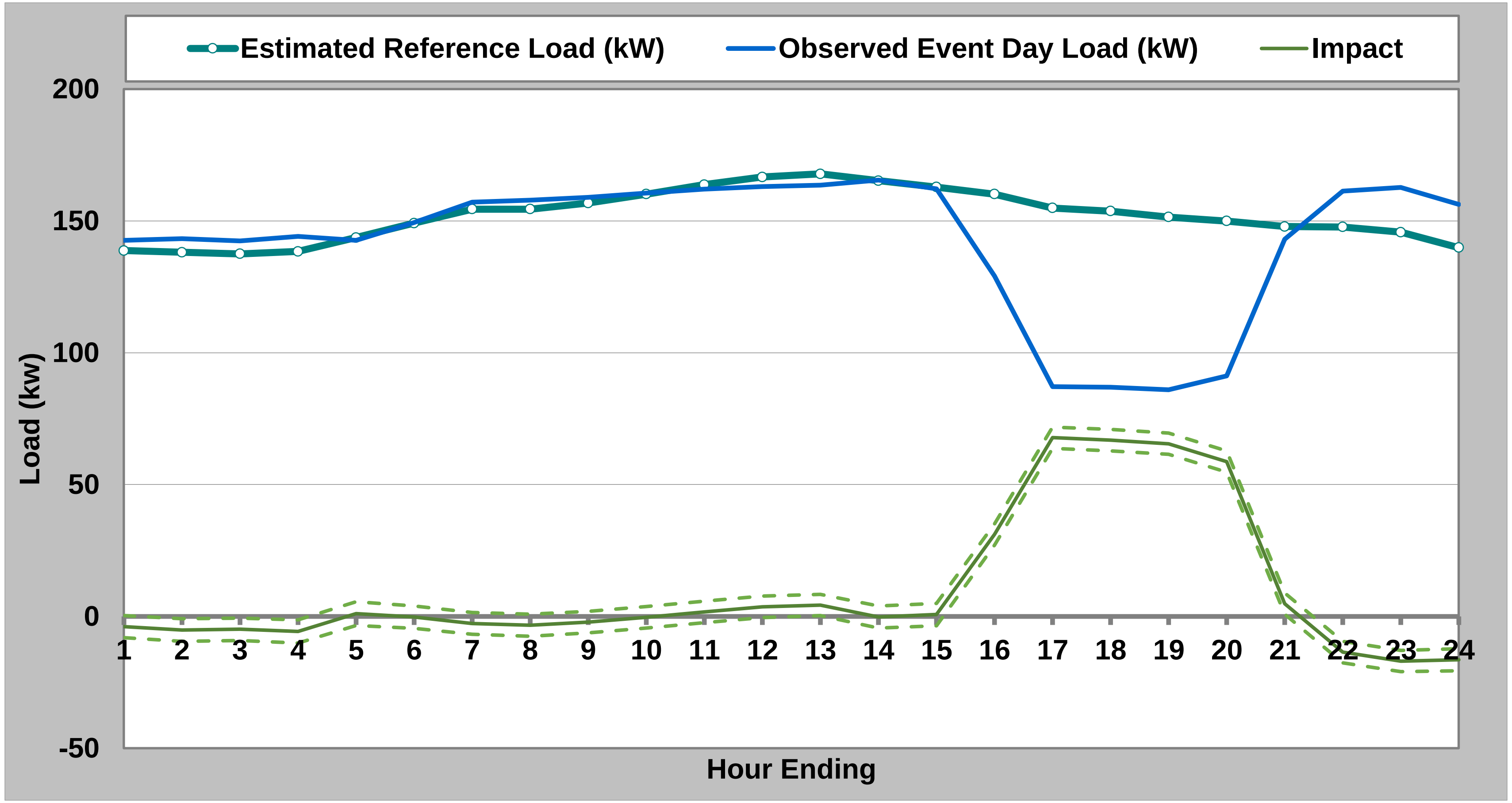
COMBINED EX-POST

Event	# of Accts	Mean Reference Load (kw)	Mean Customer Impact (kW)	Relative Curtailment (%)	Ave Event Hour Temperature
30 May 2019	191	104	17	16	82
20 Jun 2019	191	116	25	22	76
26 Jun 2019	191	116	21	18	82
22 Aug 2019	191	152	51	34	89
31 Jul 2020	163	189	71	38	105
14 Aug 2020	89	74	39	52	95
17 Aug 2020	252	138	52	37	97
18 Aug 2020	252	155	63	41	96
19 Aug 2020	252	156	65	41	90
20 Aug 2020	89	73	36	49	85
29 Sep 2020	163	175	68	39	97
02 Oct 2020	152	187	72	39	96
Typical	252	135	46	34	90

AVERAGE IMPACTS – AUGUST 18, 2020

Event Start Time:
16:00

Event End Time:
20:00



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EX-POST RESULTS BY LOAD TYPE

Event	HVAC		Pumping	
	# of Accts	Mean Customer Impact (kW)	# of Accts	Mean Customer Impact (kW)
30 May 2019	87	22	104	12
20 Jun 2019	87	26	104	25
26 Jun 2019	87	19	104	22
22 Aug 2019	87	25	104	73
31 Jul 2020	111	21	52	190
14 Aug 2020	7	-3	82	42
17 Aug 2020	118	17	134	90
18 Aug 2020	118	21	134	104
19 Aug 2020	118	20	134	107
20 Aug 2020	7	-2	82	39
29 Sep 2020	111	24	52	171
02 Oct 2020	100	20	52	182

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EX-ANTE RESULTS

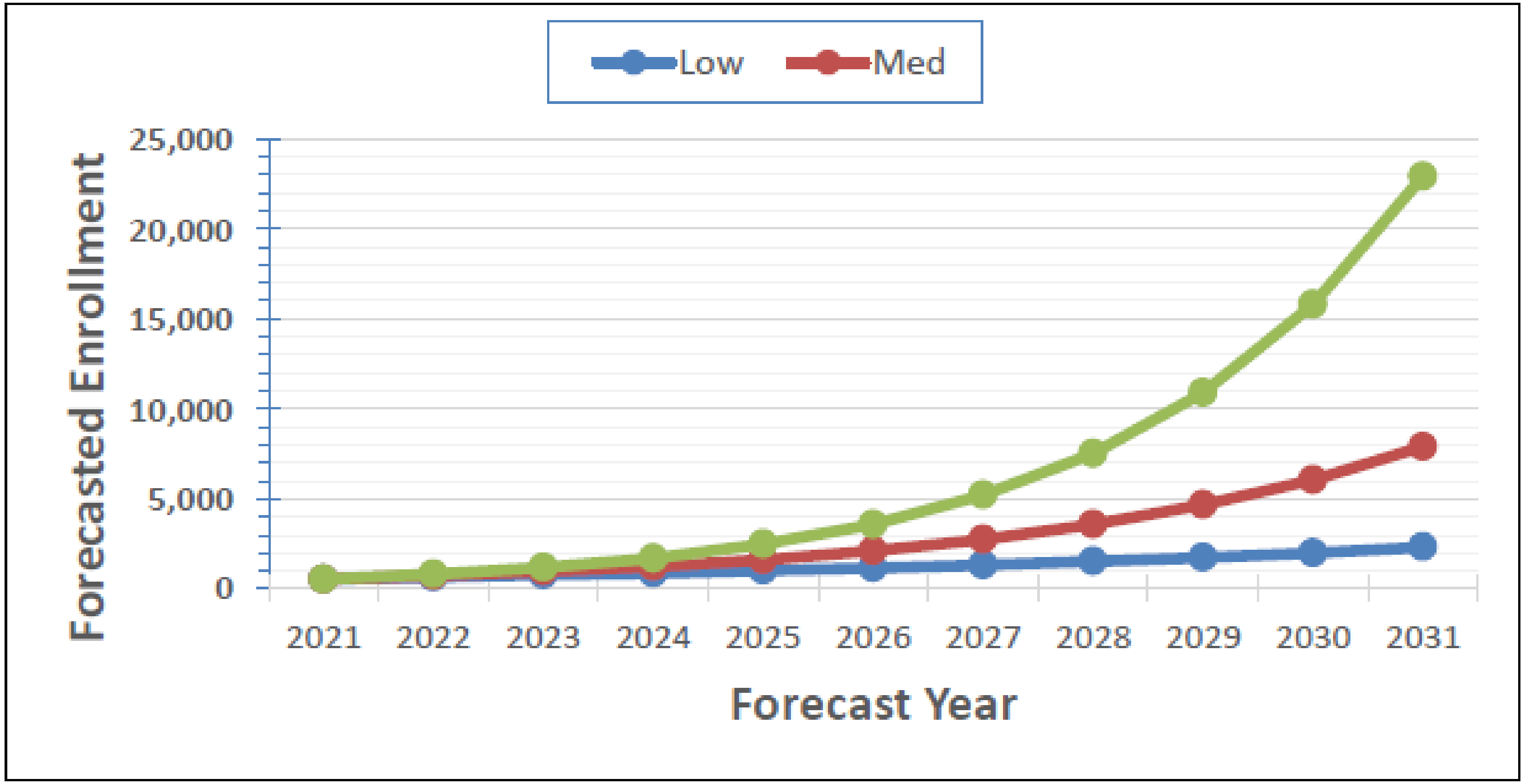
EX-ANTE METHODOLOGY

The ex-ante load impacts were estimated for the DR resource for typical event days and monthly peak days from 2021 through 2031. The ex-ante analysis used the results of the ex-post analysis. These results use predictive factors of external drivers such as, ambient temperature and customer segment. These predictive factors were then combined with forecasted weather scenario data, by geography, and Enersponse's predicted resource changes to estimate potential future impacts.

ENROLLMENT FORECATS (H/M/L)

Year	Low	Medium	High
2021	524	524	524
2022	653	733	810
2023	750	954	1,174
2024	863	1,242	1,703
2025	993	1,617	2,469
2026	1,141	2,105	3,580
2027	1,313	2,741	5,191
2028	1,510	3,570	7,526
2029	1,736	4,651	10,913
2030	1,996	6,059	15,824
2031	2,296	7,895	22,945

ENROLLMENT FORECASTS (H/M/L)



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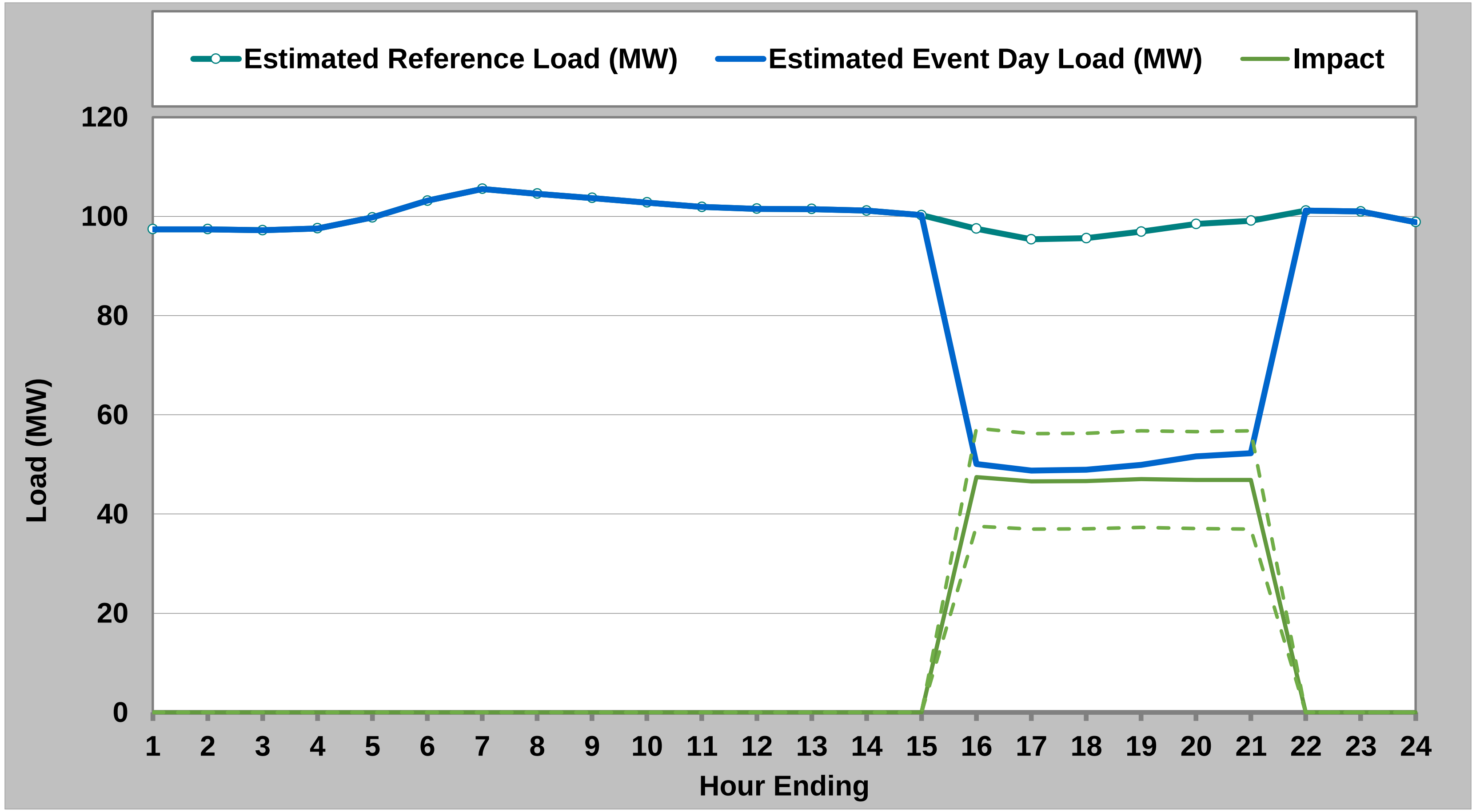
EX-ANTE RESULTS – TYPICAL EVENT DAY 2021



ENERSPONSE

COMBINED EX-ANTE RESULTS

Year	Enrollment	Aggregate Impact (MW)	Percent Impact (%)
2021	524	26.8	37%
2022	733	46.8	48%
2023	954	60.9	48%
2024	1,242	79.3	48%
2025	1,617	103.3	48%
2026	2,105	134.4	48%
2027	2,741	175.0	48%
2028	3,570	228.0	48%
2029	4,651	297.0	48%
2030	6,059	386.9	48%
2031	7,895	504.1	48%

EX-ANTE RESULTS BY LCA

Year	Big Creek/Ventura		LA Basin	
	Enrollment	Aggregate Impact (MW)	Enrollment	Aggregate Impact (MW)
2021	20	0.0	504	27.6
2022	77	6.0	656	35.9
2023	101	7.9	853	46.7
2024	132	10.3	1,110	60.8
2025	172	13.4	1,445	79.1
2026	224	17.4	1,881	103.0
2027	294	22.7	2,449	134.1
2028	381	29.6	3,189	174.6
2029	498	38.7	4,153	227.4
2030	650	50.5	5,409	296.2
2031	849	66.0	7,046	385.8

FUTURE RECOMMENDATIONS

- In the future, individual regressions continue to be used for estimating baselines.

- For some customers, day-matching may provide a more accurate and unbiased baseline, but more information about operations is needed to make this determination.

QUESTIONS

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SUNRUN

Load Impact Protocol Workshop

5.3.2021 | Alex Sherman & Rachel McMahon

Agenda

01 | Sunrun Introduction

02 | Final Proposal

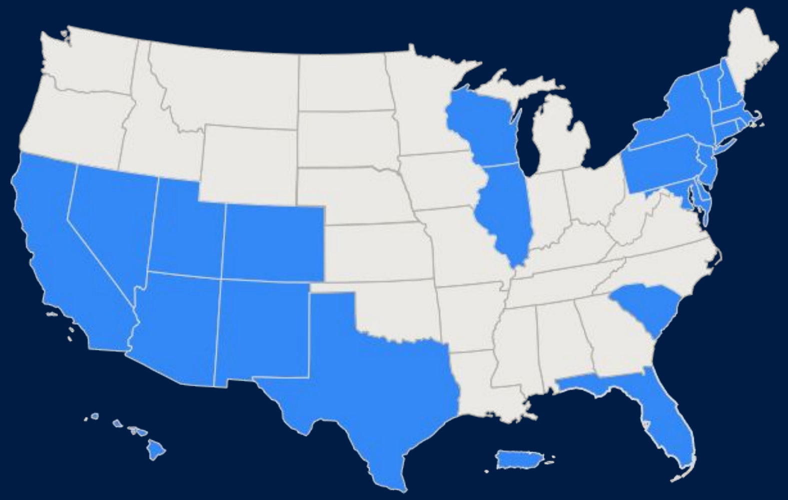
03 | Results

04 | Data

05 | Limitations of Revised Approach

06 | Recommendations

Sunrun at a Glance



We have **more than 550,000 customers** and sell our solar service in **25 states,** the District of Columbia and Puerto Rico.

OUR MISSION

To create a planet run by the sun.

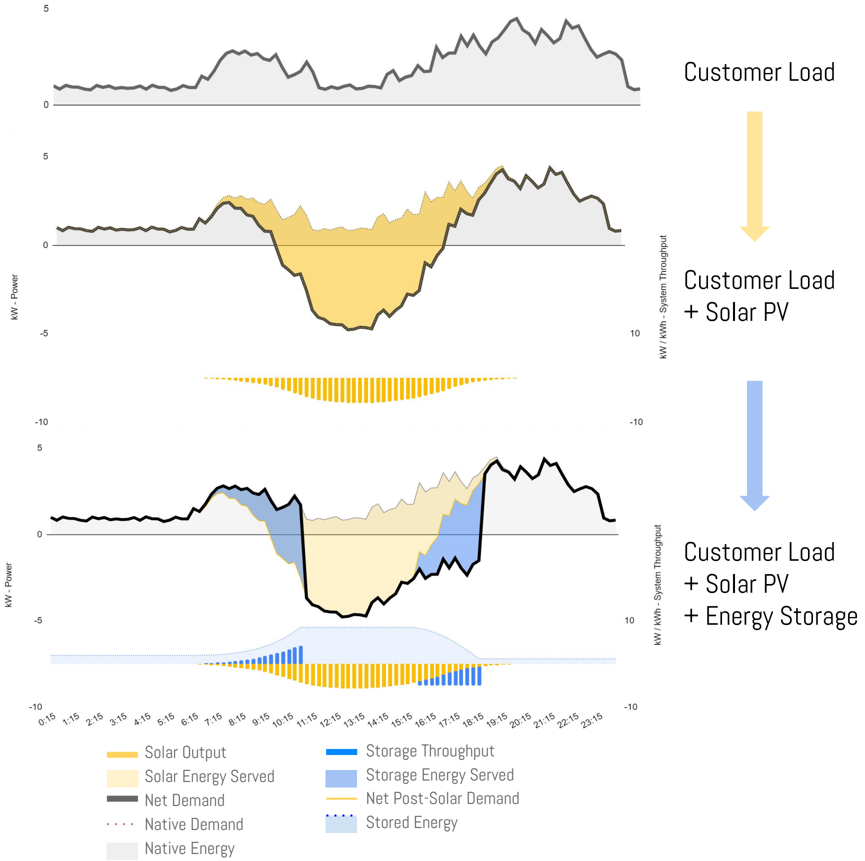
OUR BEGINNINGS

- Founded in 2007
- HQ in San Francisco
- Pioneered Residential Solar Service

OUR BUSINESS MODEL

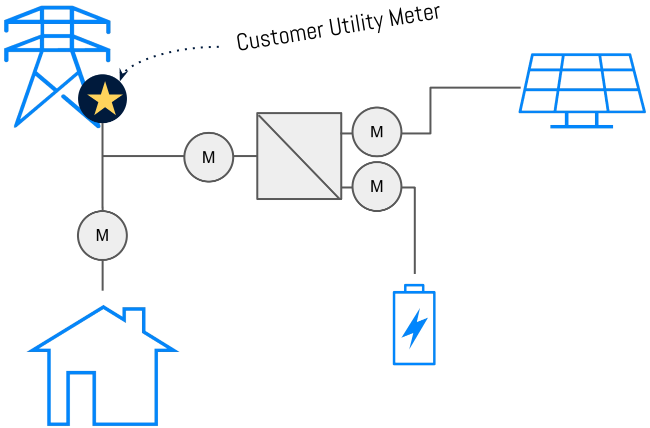
- Single and multi-family residential
- Solar only from 2007 – 2016; growing solar + storage since 2016.
- Focused on provision of customer energy historically; since 2018 have begun providing customer services (ie - demand charge and TOU management) and grid services (ie – reliability capacity and distribution loading management).

Sunrun's Brightbox: Solar + Storage

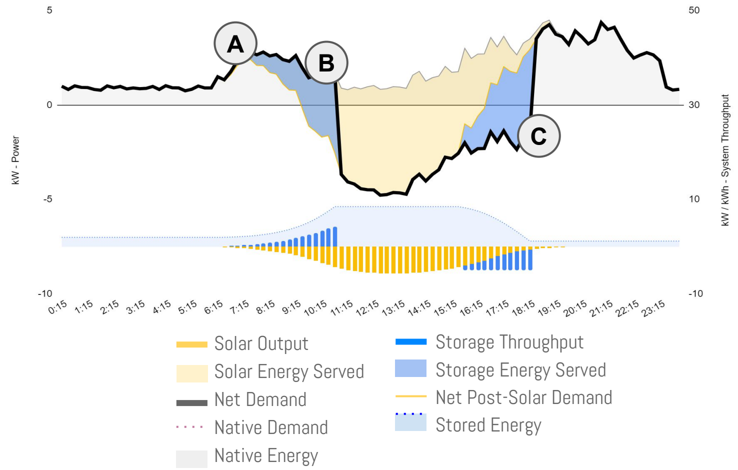


Sunrun deploys integrated solar + storage systems interconnected behind the customer's utility meter. All energy generated by the systems serve the customer first, displacing energy served by the grid.

This means Sunrun Brightboxes do not change customer behavior, but they do reduce utility demand.

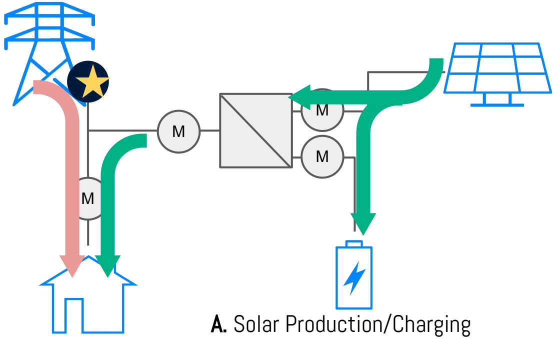


Typical Brightbox Activities

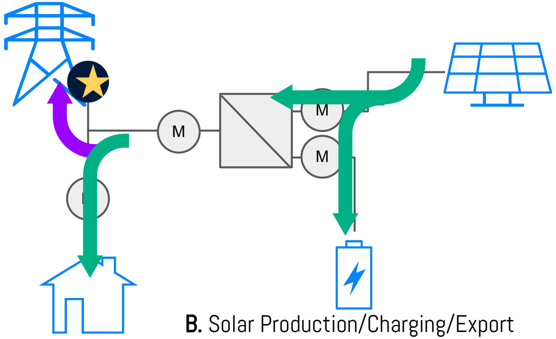


In California, Sunrun typically provides services to customers including, but not limited to:

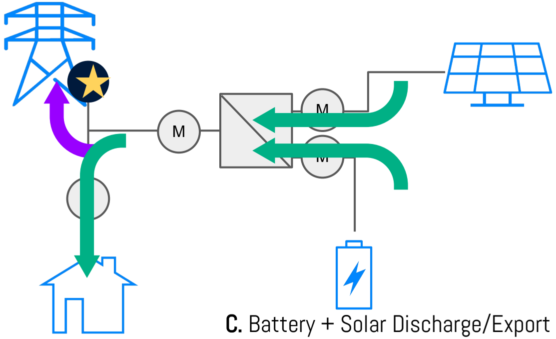
- **TOU bill management** by discharging during TOU windows
- **Minimizing solar export** by charging exclusively from solar
- **Backup power** capacity reserved exclusively for grid outage
- **Distribution system capacity, voltage controls and other grid services** by responding to utility / market signals.



A. Solar Production/Charging



B. Solar Production/Charging/Export



C. Battery + Solar Discharge/Export

Final Sunrun LIP Report for 2022

Based on feedback from parties, the methodologies Sunrun used for our final report for load impact is:

Regarding projecting the number of systems that will be deployed to deliver Qualifying Capacity:

- Sunrun projects our 2022 fleet size using executed bilateral contract obligations for RA capacity, which have revenue and penalty incentives to bring specific a volume of energy storage systems online in a given timeframe.

Regarding the Calculation of Load Impact:

- Engineering models are created for single family behind-the-meter energy storage systems participating in event-based demand response between the hours of 5:00 PM and 9:00 PM on event days.
- Engineering models assume systems are called on a daily basis, requiring daily system recharge from on-site solar.
- Calculations are made for both reference load and observed load, at both the site (measured at point of interconnection) and aggregate / fleet level.
- Load Impact is estimated using event-day and non-event-day load calculated with a site net load 10-10 baseline.
- Conservative assumptions regarding maximum RA value per site; use smallest customer product offering, average monthly available load during such hours based on the typical solar resource month, adjusted by IOU territory lat/long, all scaled to fleet characteristics.
- **COVID adjustment:** Apply a 120% scaling factor to typical annual gross load.

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Brightbox Activities Factored

In our modeling methodology, Sunrun makes the following assumptions relative to battery activity:

- **TOU bill management:** Sunrun models batteries participate in TOU activity on *non-event days only*.
  - This activity is factored into baseline calculations.
  - Sunrun does not assume battery system operation changes on non-event days to optimize baselines
- **Minimizing solar export** by charging exclusively from solar.
  - This activity is factored into baseline calculations and the modeled reference load available
- **Backup power** capacity reserved exclusively for grid outage
  - This back-up power is treated as unusable for providing RA capacity
- **Distribution system capacity, voltage controls and other grid services** by responding to utility / market signals
  - Sunrun simulates consecutive daily dispatch activity to model system's ability to recharge on a daily basis.
- **System export is not counted towards RA**

Notes on Revised Approach

- Sunrun expects to begin operation of battery fleets to provide RA in August of 2021. Until such time, ex ante models will continue to be based on engineering models and best available data.

- Requirements to use reference load **baselines** yields a less authentic measurement of capacity value for behind the meter storage than would measuring the output of the storage asset itself, as Sunrun originally proposed.

- Not allowing for measurement of energy storage-driven site-export further limits energy storage from demonstrating the full value of its capability (and delivered capacity) to the grid

- Sunrun is compelled to accept a measurement protocol that effectively reduces capacity for Sunrun aggregated fleets in each IOU by > 60%. Capacity will still be provided, but it will be undervalued and underrecognized.

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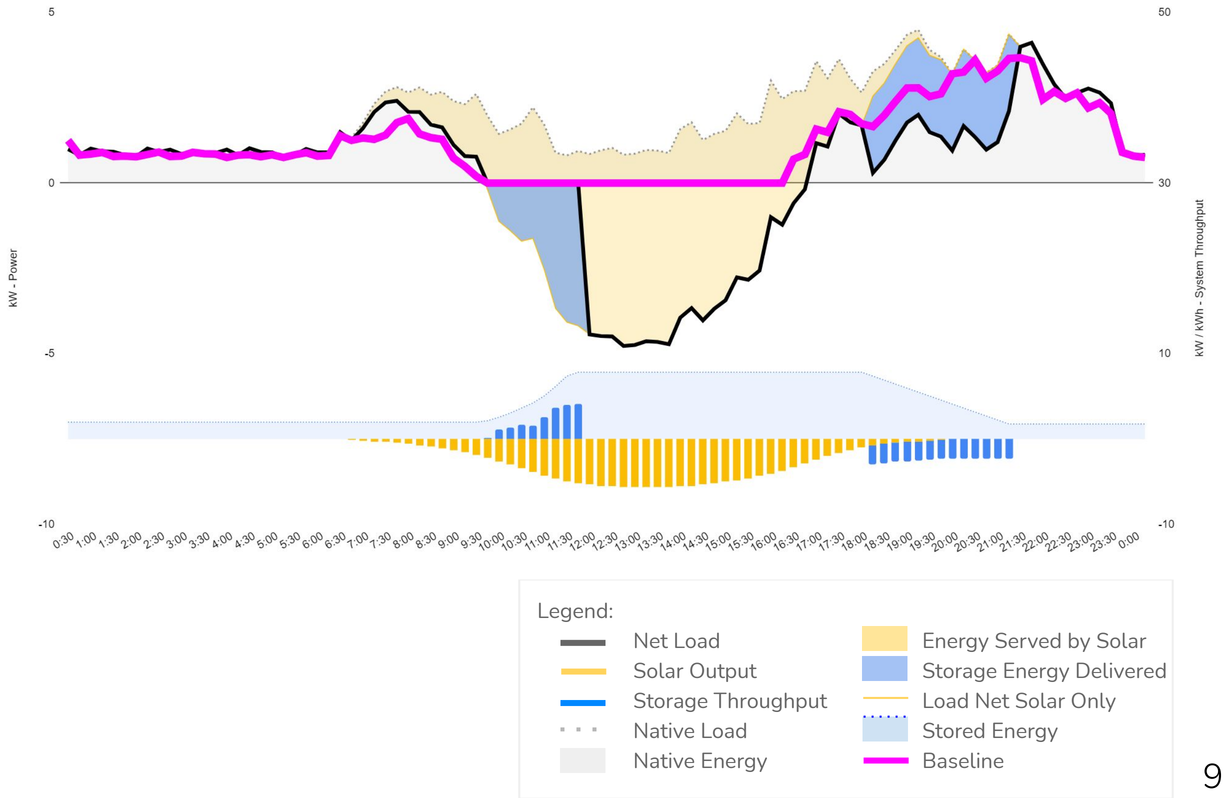
Paradigm Shift: Direct Metering

- Battery energy discharge serves customer load and reduces grid demand by commensurate amount
- Combining metered BTM storage with metered customer load provides **complete**, **comprehensive** and **empirical** views of customer energy consumption, unambiguous records of load impact on the event day itself.
- Calculating DR performance for storage-backed resources using reference load baselines and not valuing net energy export is therefore demonstrably not recognizing the full capacity value being provided



Recommendations

Clear and consistent guidance is needed for applicability of LIP to BTM batteries and hybrid systems, as well as greater recognition of the capabilities of said systems. Sunrun recommendations include the following:

Regarding the Calculation of Load Impact:

- Clarify whether BTM storage or hybrids may be “load shift” resources that are not market integrated, or whether they must use the standard 10-in-10 methodology.
- Consider additional benefits that energy storage provides compared to traditional sources of DR, such as the elimination of customer fatigue, seasonal / weather adjustments, snapback, etc.
- Permit behind-the-meter storage or hybrid assets to use directly metered output data post-event for ex-post reporting in combination with site level metering.
- For future evaluation, recommend using a combination of metered output data with engineering models/forecasts for ex-ante evaluations, to be submitted following initial events.

Thank you.

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Appendix

Description of study methodology:

The results of this study are based on IOU-specific engineering models of a typical Sunrun single family home customer with behind-the-meter energy storage systems that are participating in event-based demand response between the hours of 5:00 PM and 9:00 PM on event days, and on non-event days discharging for other customer value. These customers are modeled with system characteristics typical to these kinds of solar and storage deployments, such as PV size, inverter efficiency losses, maximum usable energy, hardware specifications and operational capabilities. Solar and battery sizes are also based on typical characteristics seen in Sunrun's typical solar and battery installations. To be conservative, the methodology used the smallest typical energy storage system size that Sunrun offers customers.

The modeled system operational characteristics include being both non-grid charging and only charged by solar; Sunrun has modeled the systems as maintaining a portion of the stored energy in the battery at all times for customer resiliency in the event of a grid outage; Sunrun has also included as a modeled behavior regular retail energy arbitrage that discharges the battery during peak pricing periods on every non-event day. All of this typical usage is baselined at the site level meter so that it is accounted for in the site 10-in-10 baseline that measures load impact.

Appendix

The following methods, assumptions and data sources were used to model customer load: *(cont'd next page)*

- Creation of a detailed, physics based engineering model based on average Sunrun system characteristics, efficiency losses, TMY data, and OpenEI load curves for single family homes. Load curves and solar production values are scaled to typical Sunrun fleet load characteristics and solar production values.
    - Residential solar system characteristics based on Sunrun's average DC system size, on a per-IOU territory basis. Inclusive of:
        - Observed kWh/kW based on historical data of currently installed systems
        - Typical weather pattern variance including low insolation periods
    - Residential energy storage system characteristics based on average specifications of LG Chem RESU10H systems paired with SolarEdge Storedge 7.6kW inverters. The model conservatively estimates only a single battery system per home, inclusive of:
        - Weighted inverter efficiency characteristics for DC-DC and DC-AC conversions and inclusive of all efficiency losses
        - Power and inverter output limitations for the system
        - Usable energy characteristics and conservative system sizing using the smallest system configuration Sunrun offers
- Weather files allow for realistic overall performance variation due to insolation differences and typical usage patterns for the highest number of customers within a utility's service territory. TMY3 weather data for modeled PV system output based on:
    - Bakersfield Meadows (PG&E)
    - Riverside Municipal Airport (SCE)
    - San Diego Montgomery Field (SDG&E)

Appendix

The following methods, assumptions and data sources were used to model customer load: *(cont'd)*

- Reference load curves for residential systems based on the Department of Energy's modeled residential load dataset using the same TMY3 information from above. These curves were then scaled so that total annualized energy usage was equivalent to typical Sunrun single family home customer electricity usage on a per-IOU basis, with a scaling factor to account for increased residential load seen during the SARS-CoV-2 pandemic. This accounts for realistic customer usage expectations and averages usage across utilities instead of indexing to only one location. Specifically, the load curve shapes used were from:
    - BASE load for Bakersfield (PG&E)
    - BASE load for Riverside (SCE)
    - BASE load for San Diego (SCE)
- Simulation of system output for a typical meteorological year and specifically the output of systems during four hours of the Must Offer Obligation window (MOO).
    - Assumes specified efficiency losses per asset manufacturer information.
    - Assumes provision of resource adequacy from energy storage system only via event based DR with an event window between 5:00 pm and 9:00 pm, called on a daily basis. This assumption is to ensure a solar backed energy storage system must recharge each day.
    - Assumes that resource adequacy values are the average monthly available during such hours based on the typical solar resource month for a particular IOU territory.
    - Assumes reserving a margin of useable energy (20%) in the storage system for customer resiliency and backup.
    - Assumes use of the system for regular customer retail energy arbitrage only on non-event days and when there is sufficient energy arbitrage value. Sunrun did not alter the model of system output so it would change operational behavior to try to optimize baselines and improve baselined performance. Moreover, the model only values performance as the difference between the 10-in-10 site level baseline for non-event days and the event day. Only site load drop is credited; systems are not credited for export. This results in a more conservative performance result than what might be expected in actual operations, which Sunrun accepts as necessary in order to simplify the model.

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Appendix

The following methods, assumptions and data sources were used to model customer load: *(cont'd)*

- Calculation of available average RA value on a per-month basis
  - Use of aforementioned assumptions for single family dwellings.
- Calculation of fleet size based on signed contracts for RA delivery in 2022.
- Estimation of individual project/asset contributions to resource adequacy value by IOU.
  - An estimate of resource adequacy allocation per site in each IOU has been based on the above noted methodology and is detailed in the attached tables of this report.
- Estimation of QC values for the 2022 RA year based on contracted capacity values for resource adequacy within each IOU territory.

Appendix

The following methods, assumptions and data sources were used to project asset deployments:

- Calculation of available average RA value on a per-month basis
  - Use of aforementioned assumptions for single family dwellings.
- Calculation of fleet size based on signed contracts for RA delivery in 2022.
- Estimation of individual project/asset contributions to resource adequacy value by IOU.
  - An estimate of resource adequacy allocation per site in each IOU has been based on the above noted methodology and is detailed in the attached tables of this report.
- Estimation of QC values for the 2022 RA year based on contracted capacity values for resource adequacy within each IOU territory.

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Original Proposal - Methodology Variant

The current load impact protocols are not designed to properly value demand response performance driven entirely by behind-the-meter energy storage. Sunrun's original—and ultimately preferred—proposal for load impact methodology is:

Regarding the Calculation of Load Impact:

- That behind-the-meter energy storage throughput creates a **direct, commensurate impact on customer load**
- That the energy storage meter is therefore the only direct, empirical way to measure energy storage's load impact;
- That the application of a baseline to measure the load impact of energy storage is an unnecessary abstraction;
- That visibility into the metered, measurable output of behind-the-meter energy storage creates sufficient evidence to confidently allow valuation of export for RA;
- That energy storage load impact is unaffected by seasonality, except in the most extreme cases
- That energy storage load impact is unaffected by customer fatigue

Voltus Load Impact Protocol

DRP Load Impact Workshop

May 3, 2021

AGENDA

- Voltus Background
- Portfolio and Program Descriptions
- Ex Post Methodology
- Ex Post Load Impacts
- Ex Ante Methodology
- Ex Ante Load Impacts

VOLTUS BACKGROUND

VOLTUS BACKGROUND

- Demand Response Provider across North America since 2016
- Track record of successful DR programs
- Entered PG&E CBP and PG&E BIP in 2019
- Awarded DRAM 2020 Capacity in PG&E and SCE territory
- Became Scheduling Coordinator in 2020
- Limited portfolio and event history in California prior to 2020
- Actively engaged in the 2021 PG&E and SCE DRAM and BIP and the PG&E CBP

VOLTUS 2020 PORTFOLIO

PORTFOLIO AND PROGRAM DESCRIPTIONS

Program Notification Basis	Program	Number of facilities enrolled 2020	2020 Event Types	Number of Dispatches	Description
Day Ahead	PG&E - CBP	79	Summer Weekday	5	The CBP operates fully as an aggregator managed program. PG&E is responsible for calling events when one of three criteria are met.
	PG&E – DRAM	270	Summer Weekday, Winter Weekday	15	The DRAM is a pay-as-bid auction system for DR RA that allows sellers to bid directly into the CAISO day-ahead market.
	SCE - DRAM	340	Summer Weekday, Winter Weekday	8	
Day Of	PG&E - BIP	84	Summer Weekday, Summer Weekend	10	The BIP is a day-of tariff-based program that provides load reductions when called upon by the CAISO. BIP participants receive 30 minutes of notification prior to events. (Voltus does not participate in SCE's 15-minute notification offerings)
	SCE- BIP*	3	Summer Weekday, Summer Weekend	9	
Voltus 2020 Portfolio		776	--	46	--

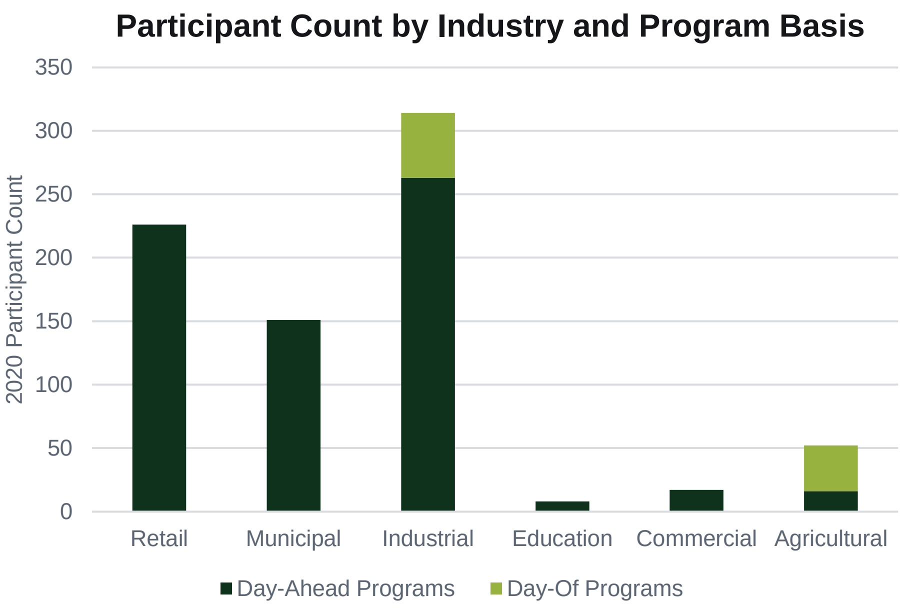
*SCE BIP results are not presented due to 15/15 rule confidentiality

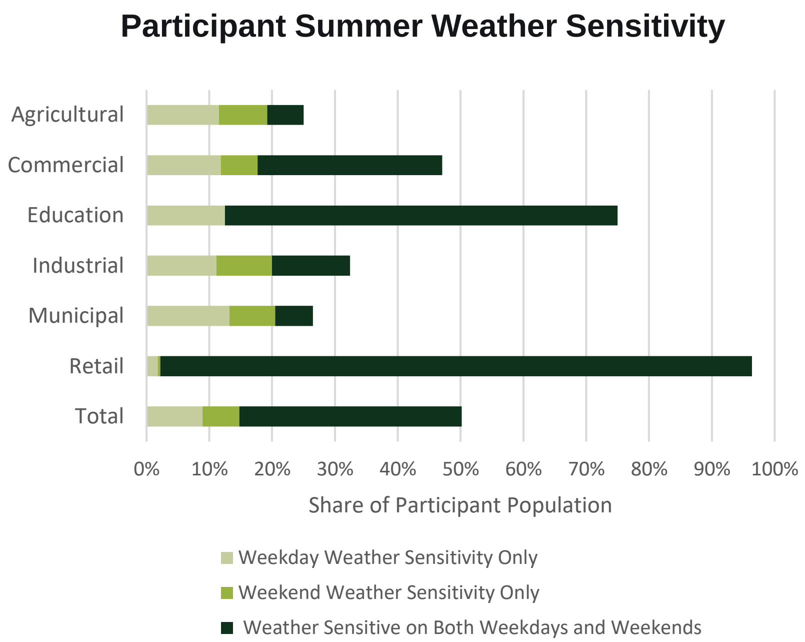
EVENT DISPATCHES IN 2020

Event Date	Day of Week	PG&E CBP Dispatches	PG&E DRAM Dispatches	SCE DRAM Dispatches	PG&E BIP Dispatches	SCE BIP Dispatches
7/30/2020	Thursday	6:00PM to 7:00PM (6 SubLAPs)				
7/31/2020	Friday	6:00PM to 7:00PM (3 SubLAPs)				
8/11/2020	Tuesday		3:00PM to 5:00PM (10 SubLAPs)			
8/14/2020	Friday			4:00 PM to 6:00 PM (5 SubLAPs)	4:02PM to 8:02PM(1 SubLAP); 4:42PM to 8:42PM (3 SubLAPs); 4:47PM to 8:47PM (3 SubLAPs); 4:52PM to 8:52PM (2 SubLAPs)	4:10PM to 7:35 PM (1 SubLAP)
8/15/2020	Saturday				2:42PM to 7:59PM (9 SubLAPs)	2:00 PM to 6:51 PM (2 SubLAPs)
8/16/2020	Sunday				6:07PM to 7:09PM (9 SubLAPs)	4:40 PM to 6:27 PM (2 SubLAPs)
8/17/2020	Monday			4:00 PM to 6:00 PM (1 SubLAPs); 4:00 PM to 7:00 PM (4 SubLAPs)	2:47PM to 6:56PM (9 SubLAPs)	2:10 PM to 6:40 PM (2 SubLAPs)
8/18/2020	Tuesday		4:00PM to 6:00PM (6 SubLAPs); 4:00PM to 7:00PM (1 SubLAPs);	3:00 PM to 8:00 PM (5 SubLAPs)	1:17PM to 6:36PM (9 SubLAPs)	12:42PM to 6:24 PM (2 SubLAPs)
8/19/2020	Wednesday	5:00PM to 7:00PM (2 SubLAPs); 5:00PM to 6:00PM (1 SubLAP)	5:00PM to 7:00PM (10 SubLAPs)	5:00 PM to 7:00 PM (5 SubLAPs)		
8/20/2020	Thursday			5:00 PM to 7:00 PM (5 SubLAPs)		
8/31/2020	Monday		3:30PM to 5:30PM (1 SubLAP); 5:00PM to 7:00PM (1 SubLAP)			
9/5/2020	Saturday				5:45PM to 7:41PM (10 SubLAPs)	4:40PM to 7:33 PM (2 SubLAPs)
9/6/2020	Sunday				4:17PM to 8:04 PM (9 SubLAPs)	3:45 PM to 5:12 PM (2 SubLAPs); 5:17 PM to 5:23 PM (2 SubLAPs); 5:50 PM to 7:26 PM(2 SubLAPs)
9/30/2020	Wednesday	4:00PM to 6:00PM (11 SubLAPs)				

The table excludes Winter DRAM events that occurred in PG&E service territory on 11/6, 11/30, 12/8 and 12/9 and in SCE service territory on 11/5 and 12/9.

PARTICIPANT CHARACTERISTICS





EX POST IMPACTS

EX POST METHODOLOGY

Individual regression models were used to estimate ex post impacts.

Individual models were selected for several reasons which include:

- Data Availability
- Event Variability
- Participant Load Variability
- Reporting Granularity

Individual customers received their best fitting model specification for several applicable scenarios which include:

- Summer Weekday Models
- Summer Weekend Models
- Winter Weekday Models

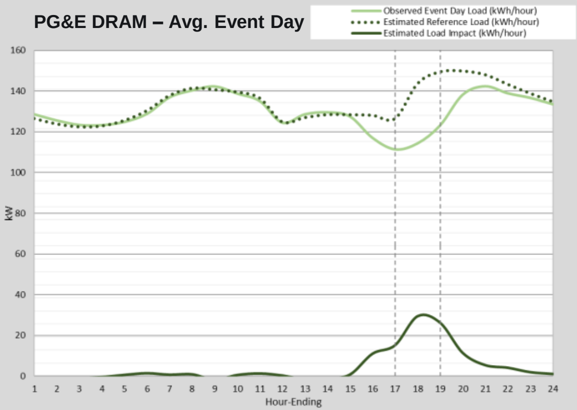
Model Fits (MAPE and RMSE) were examined on a set of event like holdout days. The model with the best out-of-sample predictions for each facility was set aside as the final model.

EX POST IMPACTS

PG&E and SCE DRAM Average Event Day Impacts

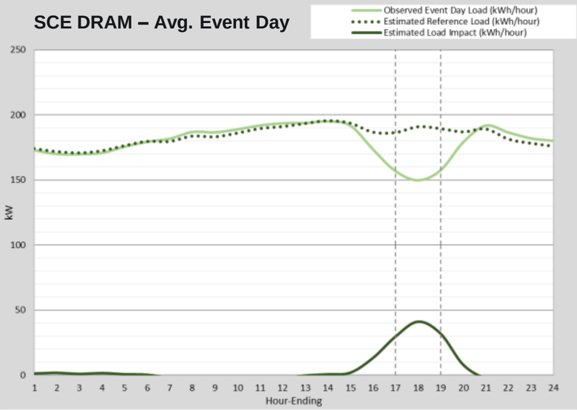
PG&E DRAM Ex Post

Event Type	Event Times PST	Number of Facilities Avg. Event	Mean Impact (kW)	Percent Load Reduction	Average Total MW Reduction	Average Event Temperature
Average Event Day	4:00PM to 7:00PM	94	23.7	16.9%	2.2	80.3 F
Max MW Impact (8/18/2020: Dispatch 1)	4:00PM to 6:00PM	132	56.0	36.9%	7.4	93.2 F



SCE DRAM Ex Post

Event Type	Event Times PST	Number of Facilities Avg. Event	Mean Impact (kW)	Percent Load Reduction	Average Total MW Reduction	Average Event Temperature
Average Event Day	4:00PM to 7:00PM	286	34.3	18.2%	9.8	90.3 F
Max MW Impact (8/19/2020: Dispatch 1)	5:00PM to 7:00PM	340	44.3	20.8%	15.1	88.4 F



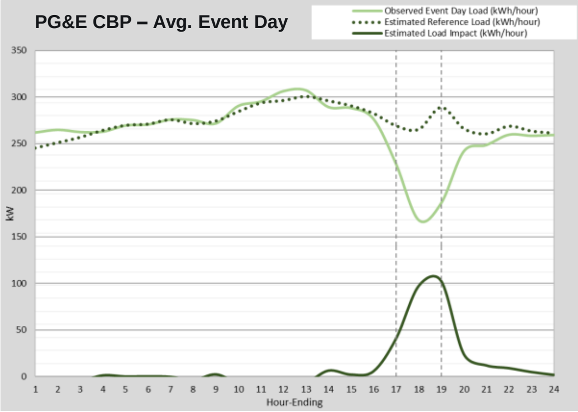
EX POST IMPACTS

PG&E CBP and PG&E BIP Average Event Day Impacts

PG&E CBP Ex Post

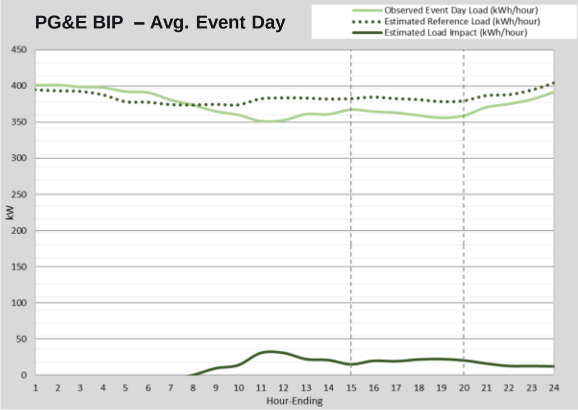
Event Type	Event Times PST	Number of Facilities Avg. Event	Mean Impact (kW)	Percent Load Reduction	Average Total MW Reduction	Average Event Temperature
Average Event Day	4:00PM to 7:00PM	51	69.2	25.9%	1.8	85.3 F
Max MW Impact* (9/30/2020: Dispatch 1)	4:00PM to 6:00PM	26	100.1	33.8%	5.1	87.3 F

*Actual maximum MW impacts occurred on 7/30/2020, but are not included due to confidentiality



PG&E BIP Ex Post

Event Type	Event Times PST	Number of Facilities Avg. Event	Mean Impact (kW)	Percent Load Reduction	Average Total MW Reduction	Average Event Temperature
Average Event Day	3:00PM to 8:00PM	59	21.1	5.5%	1.2	89.1 F
Max MW Impact (9/6/2020: Dispatch 1)	5:00PM to 7:00PM	83	58.7	15.9%	4.9	87.3 F



EX ANTE IMPACTS

EX ANTE METHODOLOGY

The ex ante methodology used adjusted customer specific regressions from the ex post analysis.

- Predicted per-customer weather-adjusted reference loads
- And the per-customer average impact from 4pm to 9pm based on RA window and most prevalent participant event hours

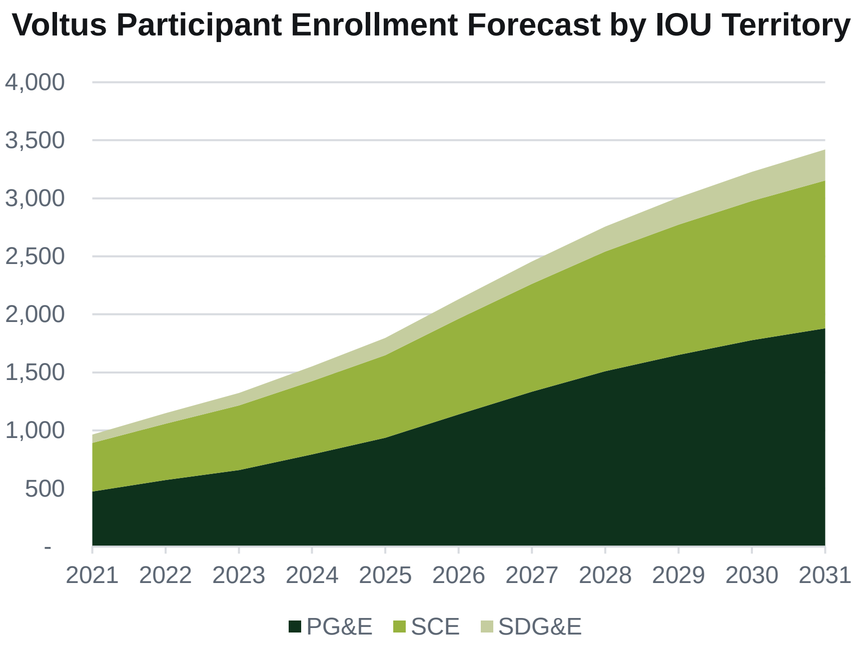
These impacts are applied to the participant enrollment forecast to calculate total ex ante MW

Total Participant Event Hours By Program and Hour

Hour Starting PST	Hour Ending PST	PG&E BIP	PG&E CBP	PG&E DRAM	SCE BIP	SCE DRAM	Total
12	13	-	-	-	1	-	1
13	14	59	-	-	3	-	62
14	15	126	-	-	9	-	134
15	16	249	-	166	10	340	764
16	17	328	51	287	16	1,020	1,702
17	18	434	74	303	20	1,619	2,449
18	19	530	78	195	15	1,246	2,064
19	20	314	-	-	4	340	658
20	21	67	-	-	-	-	67

EX ANTE FORECAST

- Ex Ante forecasts were provided by Voltus
- Voltus expects participant growth for existing PG&E and SCE programs, as well as growth into SDG&E territory.
- Participants in Voltus programs are expected to total 976 in 2021, 1,148 in 2022 and grow to 3,422 by 2031



EX ANTE IMPACTS

Utility Territory	Year	Participants	Average Aggerate System Peak Event Hour Reduction (MW)*			
			CAISO 1-in-10	CAISO 1-in-2	Utility 1-in-10	Utility 1-in-2
PG&E	2021	472	28.9	28.0	29.9	28.7
	2031	1,874	100.5	97.4	103.6	99.8
SCE	2021	419	16.0	15.5	16.4	15.6
	2031	1,271	47.6	46.2	48.8	46.5
SDG&E	2021	85	4.2	4.1	4.3	4.2
	2031	274	13.5	13.1	13.9	13.3
Statewide	2021	976	49.1	47.6	50.6	48.4
	2031	3,419	161.7	156.7	166.3	159.5

*All scenarios presented represent system peak weather scenarios in the month of August

Statewide, the Voltus Portfolio is anticipated to provide 47 to 50 MW of curtailable load in 2021 depending on event conditions

QUESTIONS

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Load Impact Evaluation: *SCE Demand Response Aggregator Contracts*

Dan Hansen
Christensen Associates Energy Consulting

Workshop on the Demand Response Provider 2021 Load Impact Protocol Final Reports

May 2021

Presentation Outline

1. Resource Description
2. *Ex-post* Methodology
3. *Ex-post* Load Impacts
4. *Ex-ante* Methodology
5. *Ex-ante* Load Impacts

1. Resource Description

- Three Demand Response Aggregators (DRAs) had active contracts during 2020:
  - Hybrid Electric Building Technologies (Hybrid)
  - Stem Energy (Stem)
  - NRG Curtailment Solutions (NRG)
- The DRAs enrolled commercial and industrial customers to provide demand response within SCE's service territory
  - DRAs nominate customers on a monthly basis
  - SCE dispatched the contracts according to the associated terms
  - DRA is responsible for meeting the contract obligations
- Two additional DRAs have contracted with SCE for upcoming years:
  - Swell Energy (Swell): two contracts beginning in 2021
  - Sunrun Inc. (Sunrun): two contracts beginning in 2023

1. Resource Description:
Maximum Capacity for 2020 DRA Contracts

Month	Total Contract Capacity (MW)			
	8 - 10 a.m.	10 a.m. - 6 p.m.	6 - 8 p.m.	8 - 9 p.m.
January	35	57.7	46.2	41.2
February	35	58.4	46.9	41.9
March	43.747	67.447	47.200	42.200
April	43.870	66.151	45.781	40.781
May	43.946	67.021	46.575	41.575
June	45.254	69.147	57.393	52.393
July	50	75	58.5	53.5
August	50	75	58.5	53.5
September	50	75	58.5	53.5
October	50	75	58.5	53.5

There was a small decrease in capacity while Shelter-In-Place (SIP) orders for COVID-19 were in effect, primarily during April and May

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2. *Ex-post* Methodology

- Estimated customer-specific regression models with the customer's hourly usage as the dependent variable
- Models are used to simulate reference loads that would have occurred in the absence events
- The explanatory variables include:
  - Hour of day
  - Day of week
  - Month of year
  - A COVID indicator variable (March 15, 2020+)
  - A morning load variable (average load from midnight to 10 a.m., except for customers with early event hours)
  - Temperatures, expressed in several ways (e.g., current hour, average daily, maximum daily)

2. *Ex-post* Methodology (2)

- Data included in the model
  - January through October 2020
  - Exclude event hours plus at least 3 hours following the event
    - If the event starts at 5 p.m. or later, the rest of the day is excluded
    - Needed to include some event-day data to improve estimates for contracts with a high frequency of events
  - Exclude data prior to the customer's first nominated month, which ensures that storage is in place (if applicable)
- Model validation
  - Estimated a common specification excluding ~12% of the data (randomly selected non-event days)
  - Compared predicted and observed values on withheld days and adjusted the customer's regression specification as needed
- Estimated load impact = the model's predicted load for the event hour minus the observed load

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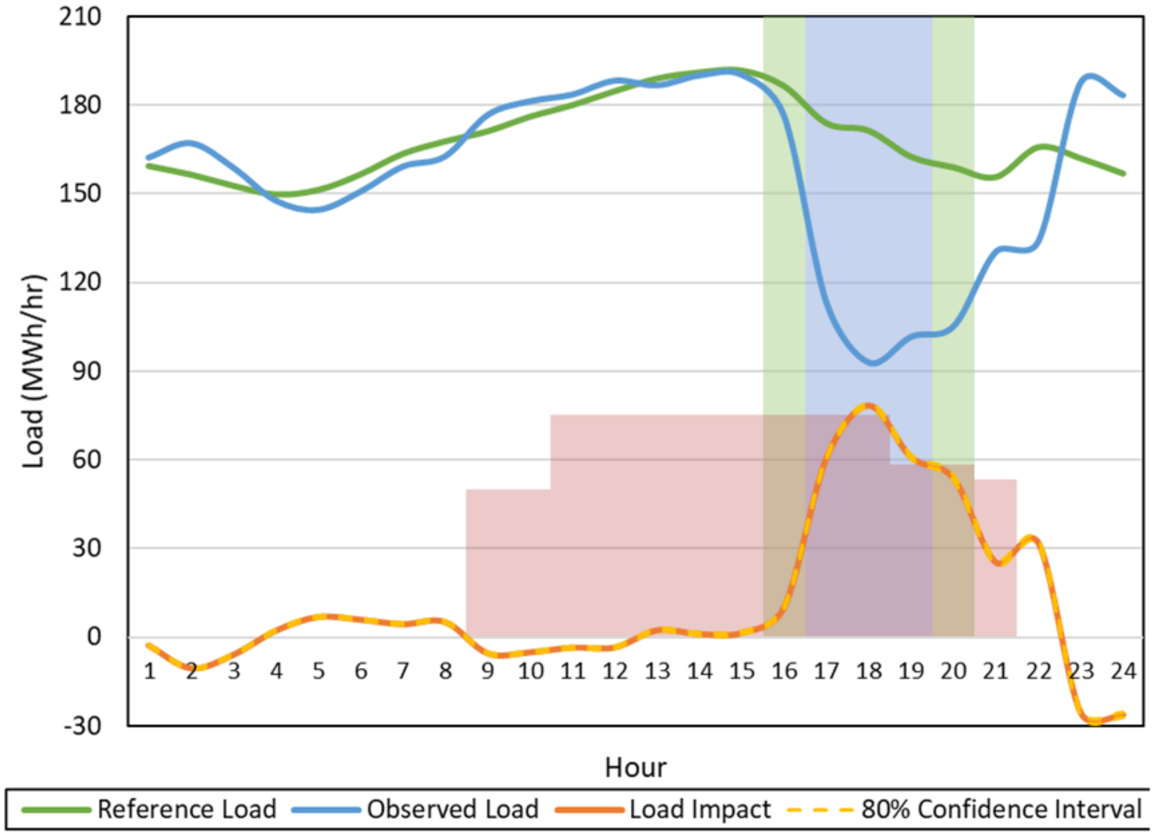
3. *Ex-post* Results
Average Event Hour with Full Dispatch

Date	Avg. Customers Dispatched	Avg. Event Hours	Average Contract Amount (MW)	Reference Load (MW)	Load Impact (MW)	80% Confidence Interval		% Impact	% of Contract Amount
						10%	90%		
8/13	326	6-8 p.m.	58.5	146.3	64.1	63.5	64.8	44%	110%
8/14	326	5-8 p.m.	64.0	153.5	60.9	60.0	61.8	40%	95%
8/17	326	4-7 p.m.	69.5	160.3	59.1	58.3	59.9	37%	85%
8/18	326	4-7 p.m.	69.5	169.3	66.7	66.2	67.2	39%	96%
8/19	326	5-8 p.m.	64.0	168.8	72.7	72.0	73.3	43%	114%
8/20	326	5-8 p.m.	64.0	165.1	64.9	64.2	65.5	39%	101%
9/4	328	5-7 p.m.	66.8	148.9	63.7	62.9	64.4	43%	95%
9/8	328	6-7 p.m.	58.5	144.8	61.5	60.9	62.0	42%	105%
10/1	329	5-7 p.m.	66.8	154.5	62.9	62.3	63.4	41%	94%
10/14	320	5-7 p.m.	66.8	149.8	56.8	56.3	57.3	38%	85%
10/15	320	5-7 p.m.	66.8	152.9	56.6	56.1	57.2	37%	85%
10/16	319	4-7 p.m.	69.5	149.2	56.4	55.8	57.1	38%	81%

3. *Ex-post* Results

August 18, 2020 Hourly Load Impacts



Blue shading = Full dispatch hours
Green shading = Partial dispatch hours
Red shading = Contract quantities

4. *Ex-ante* Methodology

- SCE provided a forecast of monthly capacity commitments by contract (replaces the enrollment forecast typically used in a load impact study)

- Simulate customer-specific reference loads for all required scenarios (by month and weather scenario)
  - Same as ex-post regression model but omitting the morning load variable

4. *Ex-ante* Methodology: *Contracts in the Ex-Post Study*

- Load impacts are simulated from a model using ex-post estimates
  - Estimated at the contract level using only events in which all resources were dispatched
  - Exclude ramping-up periods and periods when COVID adjustments were made to the contract requirements

- Load impact model
  - $Impact_{e,h} = a + b^{Mean17} \times Mean17_e + \Sigma_{hr} (b^{hr} \times Hr\_of\_Evt_{e,h}) + e_{e,h}$
  - *Mean17* is dropped if the coefficient is not statistically significant

4. *Ex-ante* Methodology: *Contracts in the Ex-Post Study (2)*

- Contracts have a maximum 4-hour event duration, whereas the Resource Adequacy window is 5 hours long
  - Two contracts: simulate all 5 hours to reflect the resource's potential in each hour of the RA window
  - One contract can't be called from 8 to 9 pm; we simulate a 4-hr event

- Forecast contract quantities matched ex-post contract quantities, so no adjustment was needed for that

4. *Ex-ante* Methodology: *Contracts NOT in the Ex-Post Study*

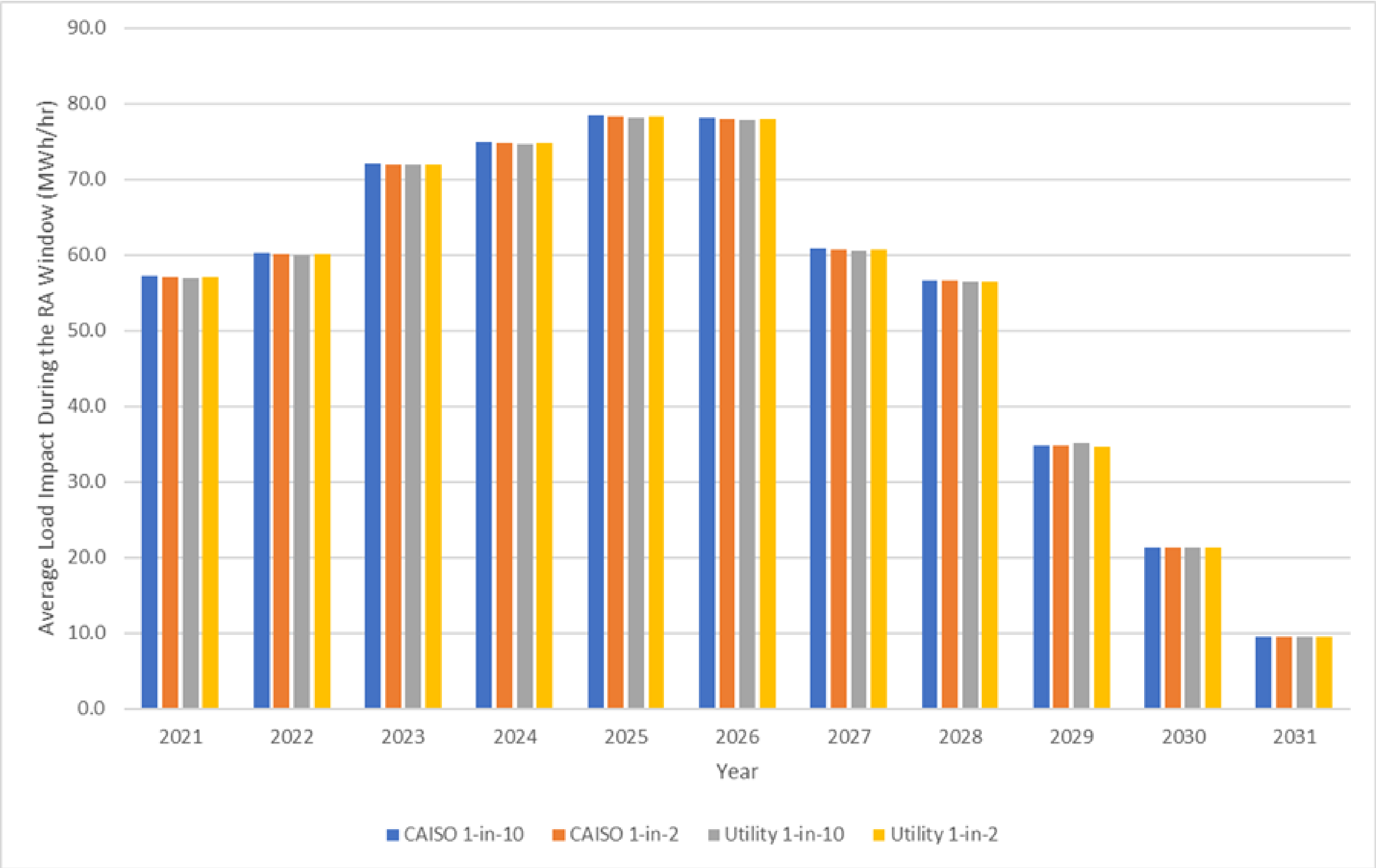
- For contracts not in the ex-post study, we have no customer load data or historical performance upon which to base the ex-ante forecast

- We follow the assumption from the previous evaluation, applying an assumed percentage to the contract value to forecast the load impacts that will be provided

5. *Ex-ante* Load Impacts: *Forecast Contract Quantities (MW)*

Month	2021	2022	2023	2024
Jan	64.1	61.9	69.4	77.9
Feb	64.1	61.9	69.3	77.7
Mar	64.1	62.0	70.1	78.8
Apr	64.1	62.0	70.1	78.9
May	64.1	62.1	70.5	79.4
Jun	64.2	62.9	71.2	79.6
Jul	64.2	64.6	72.0	80.0
Aug	64.2	64.7	77.2	80.2
Sep	64.2	64.7	77.1	80.1
Oct	64.2	64.4	76.5	79.4
Nov	64.2	64.4	76.3	79.1
Dec	65.0	66.7	75.0	77.5

5. *Ex-ante* Load Impacts:
Average August RA Window Impacts (MW)



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5. *Ex-ante* Load Impacts:
August 2021 SCE 1-in-2 Impacts (MW)

Figure reflects only contracts included in the ex-post study

Questions?

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