Load Impact Evaluation: *PG&E's SmartAC™ Program*

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DRMEC Spring Workshop

April 29-30, 2021

Presentation Outline

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

1. SmartAC™ Program Description

- Direct load control AC cycling program for residential customers
- Participants receive one-time incentive, can opt-out of events
- SmartAC integrated into CAISO wholesale market in PY2018
- Events up to 6 hours per day (May – October):
  - **CAISO market awards**
  - System or local area emergencies for PG&E capacity
  - Limited testing for a maximum of 100 hours per summer
- Serial Number Events: random sample of full territory
- Sub-LAP Events: all customers within a sub-LAP called
- 90,000 enrolled (May 2020), 10,700 dually enrolled SmartRate

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2. *Ex-post* Methodology: Sub-LAP Events

- Approach: *matched control group* + difference-in-differences
- Two-Stages of Matching:

1) 3-to-1 matching using all potential control customers
   - Nearest neighbor matching on average monthly usage, weather station, CDD60, CARE, NEM, dwelling type, AC usage level, rate schedule
2) 1-to-1 matching on selected controls from first stage
   - Propensity score matching using interval load data for non-event day loads, CARE, NEM, dwelling type, and AC usage level
   - Matches segmented by sub-LAP
   - Two 24-hour average load profiles used for matching: hot days (top 10%) and a selection of cooler days (25^{th} to 50^{th} percentile)

2. *Ex-post* Methodology: Serial Events

- No need for matched control group
- Withheld serial group serves as a randomly determined control group
- Use difference-in-differences and non-event days in regression to control for any remaining differences between treatment and control group
- The 8/18 serial test event (with serial group 7 withheld) is the basis for our sub-group analyses

3. *Ex-post* Load Impacts: *Events*

Date	SmartRate™ Event?	Reason	Event Hours (p.m.)	Sub-LAPs/Serial Groups Dispatched	# Customers Dispatched
8/14	Yes	Market	4:00-6:00	PGEB, PGKN, PGNB, PGNC, PGNP, PGP2, PGST, PGZP	43,604
		Emergency	6:05-8:22		
		Market	5:00-7:00	PGCC, PGF1, PGSI	26,550
		Emergency	7:05-8:22		
		Emergency	5:38-8:21	PGFG, PGSB	9,384
8/15	No	Market	4:00-6:00	PGCC, PGEB, PGF1, PGKN, PGNC, PGNP, PGP2, PGST	62,555
			5:00-7:00	PGNB, PGSI	15,870
8/17	Yes	Market	4:00-6:00	PGEB, PGF1, PGKN, PGNB, PGNC, PGNP, PGSI, PGST, PGZP	65,780
8/18	Yes	Test	4:19-7:00	All Sub-LAPs, Serial Group 7 withheld	71,444
8/19	Yes	Market	4:00-6:00	PGEB, PGF1, PGKN, PGNB, PGP2, PGSI, PGST, PGZP	58,120
			5:09-6:00	PGCC	241
			6:00-8:00	PGNC	547
9/5	No	Market	4:00-6:00	PGEB, PGF1, PGSI	47,526
9/6	Yes	Market	3:00-6:00	PGCC, PGEB, PGKN, PGNB, PGNC, PGNP, PGP2, PGSI, PGST, PGZP	55,853
			5:00-8:00	PGF1	12,904
9/7	No	Market	4:00-6:00	PGEB, PGF1, PGKN, PGNB, PGNC, PGNP, PGSI, PGST, PGZP	75,122
9/8	No	Market	4:00-6:00	PGNB, PGST	7,775
9/27	No	Market	4:00-6:00	PGCC, PGP2, PGSB	11,160
9/28	No	Market	4:00-6:00	PGCC, PGFG, PGNC, PGP2, PGSB	13,593
9/30	No	Market	5:00-6:00	PGSI	14,173
10/1	No	Market	3:00-5:00	PGFG	1,817
10/15	No	Market	5:00-7:00	PGFG, PGP2	5,185
			6:00-8:00	PGCC, PGSB	7,786
10/16	No	Market	4:00-6:00	PGSB	7,545
			5:00-7:00	PGFG	1,817

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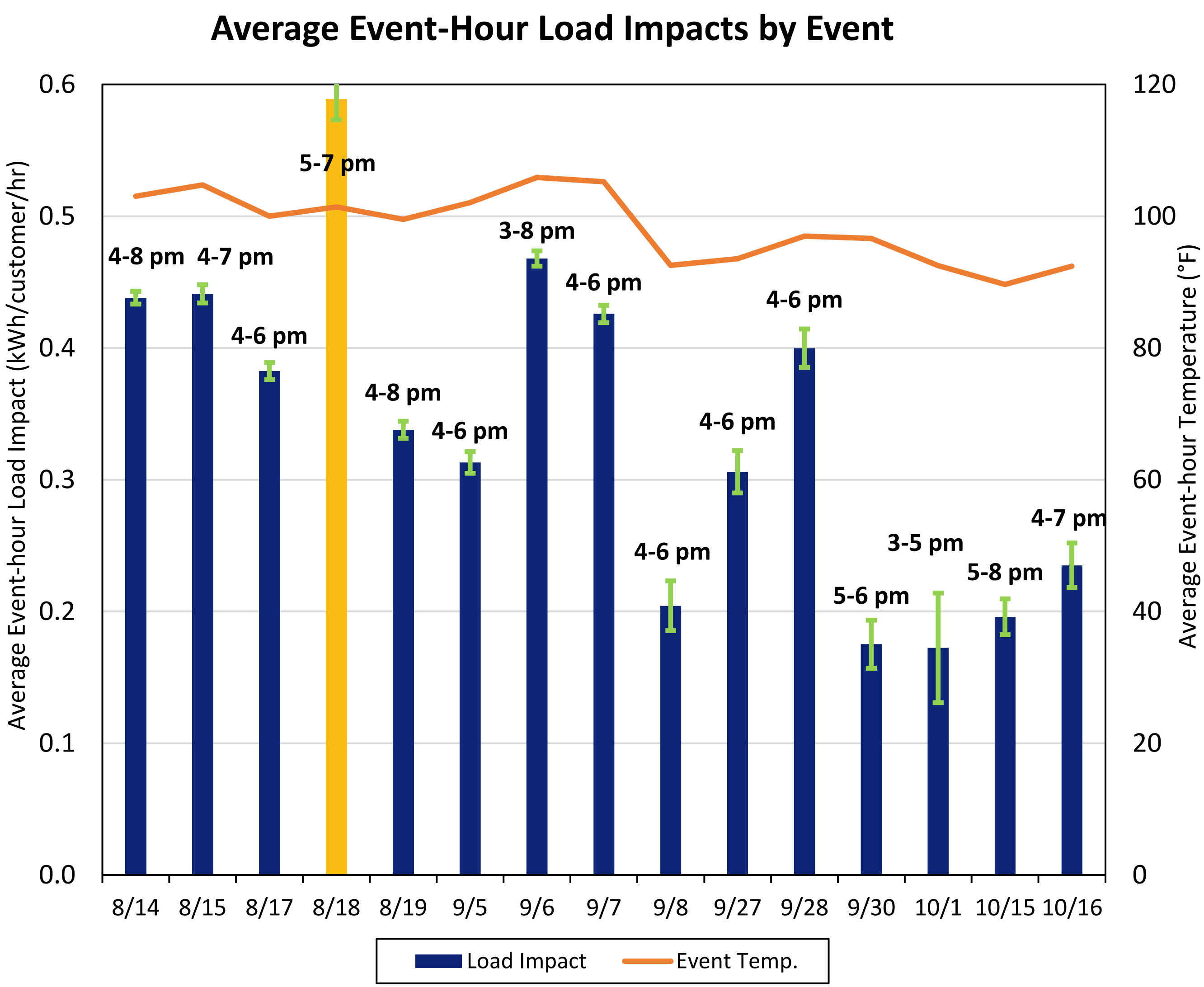
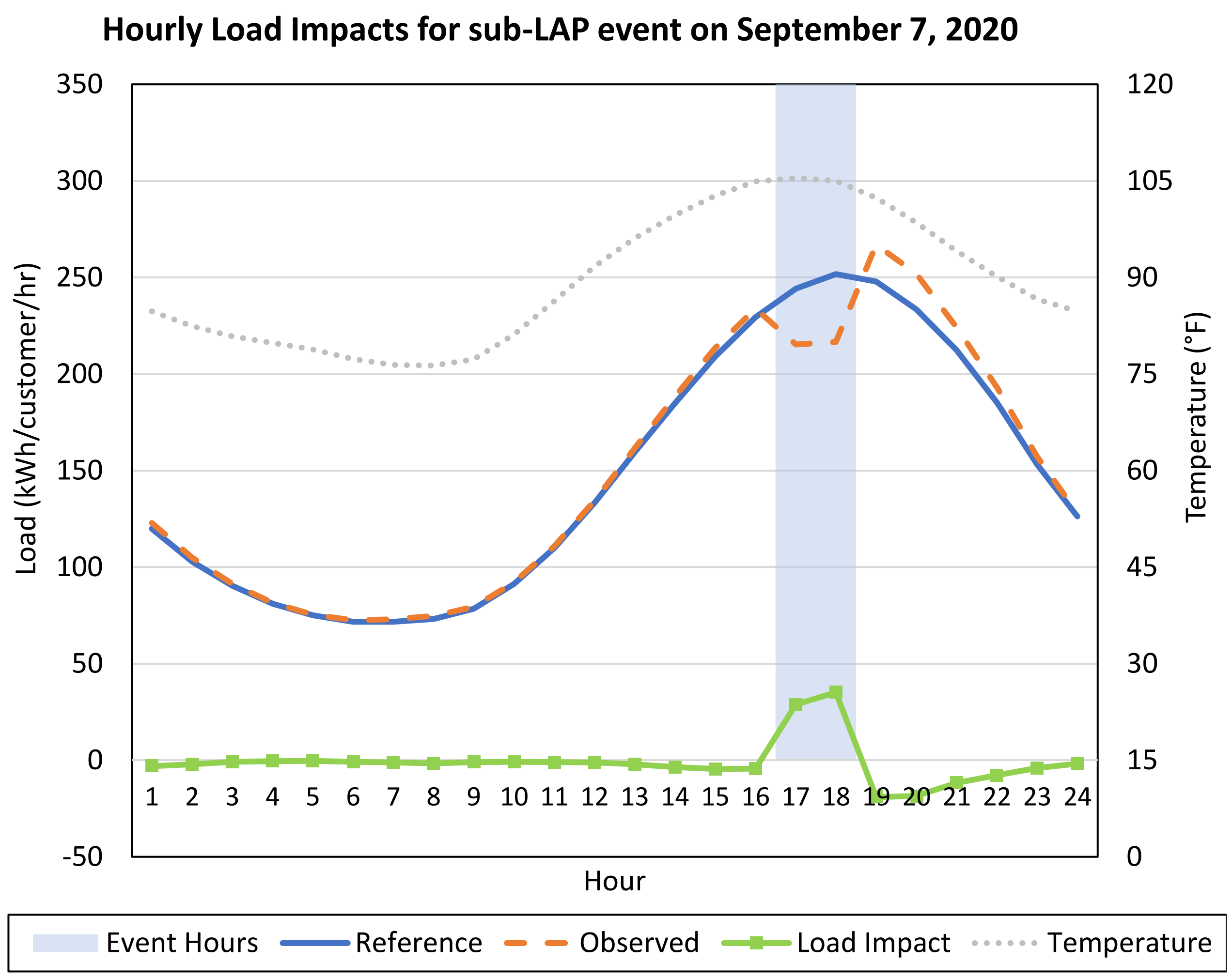
3. *Ex-post* Load Impacts



- Overall: 0.17 - 0.59 kWh/customer/ hour
- Serial event (gold) highest load impact
- Temperature, sub-LAPs called explain load impact variation
- Weekend/Holiday events comparable
- Sub-group results similar to PY2019 evaluation (e.g., CARE, NEM)

3. *Ex-post* Load Impacts



- 75,122 customers called
- 4-6 p.m.
- Peak of 35.1 MWh/hour during hour 2 of event (5-6 p.m.)
- Post-event snapback peaks at 19.1 MWh/hour
- Average per-customer load impact 0.43 kWh/customer/hr

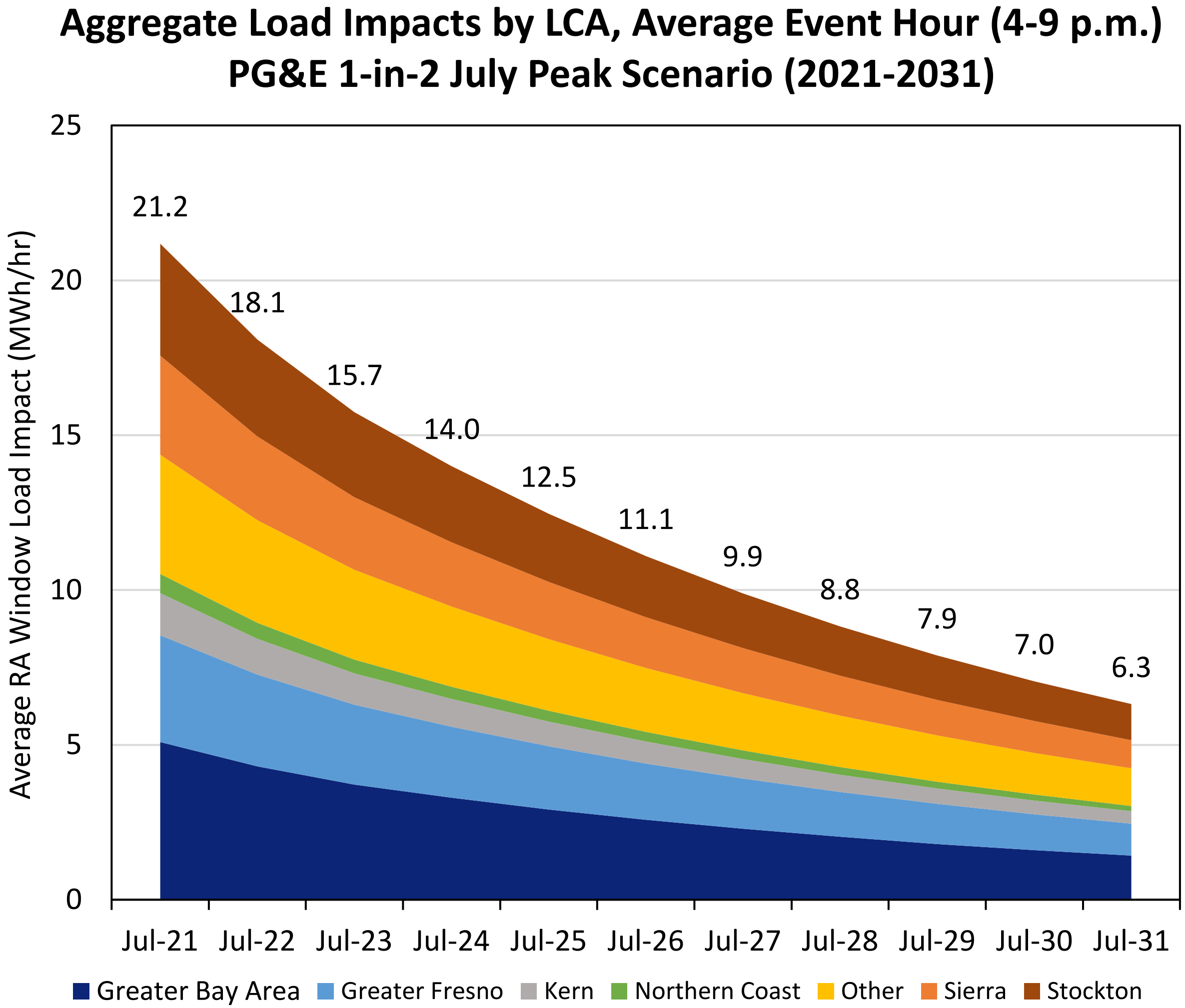
4. *Ex-ante* Methodology

- **Change in methodology for PY2020**
  - *Ex-ante* load impacts simulate a sub-LAP event (to reflect prevalence), previously simulated a system-wide serial event
  - *Ex-ante* load impacts developed from *ex-post* load impacts from all events in PY2020, simulating load impacts for the sub-LAP events
  - Previous evaluation used only serial event load impacts for *ex-ante*
- Method: Regress load impact/reference load on weather
  - Temperature, Mean8 x sub-LAP (avg. temp. first 8 hours of the day for each sub-LAP)
  - Controlling for hour of day, sub-LAP
- Combine estimates with weather scenarios to simulate per-customer *load impacts* for each:
  - Weather scenario (*e.g*. CAISO 1-in-2 on an August peak day)
  - Event Hour (restricted to resource adequacy window, 4-9 p.m.)
  - Customer-type (SmartAC-only vs. Dually Enrolled)

4. *Ex-ante* Methodology (2)

- *Reference loads* were developed for each month, sub-LAP, and enrollment segment (SmartAC-only and dually enrolled) using:
  - Non-event days: Non-holiday weekdays
  - Parameters obtained from regressions of per-customer hourly usage as a function of weather (CDD60) and load shape variables
  - *Ex-ante* weather data and day-type characteristics (*e.g*. temperatures on a CAISO 1-in-2 August peak day)
- COVID shelter-in-place (SIP) Adjustments to reference loads
  - Based on comparison of reference loads for 2019 and 2020 for customers enrolled in both years
  - Normalize results to conform with levels assumed in PG&E's SIP forecast adjustments
- Per-customer reference loads and load impacts were scaled using PG&E's forecast enrollments (by month, year, and dual enrollment status)

5. *Ex-ante* Load Impacts



- PG&E Enrollment Forecast: decline by 11% / year
- PG&E intends to minimize marketing efforts to back-fill attrition, limited device repair
- Aggregate Load Impacts decline by 11% / year after 2022
- Larger 14% declines before 2022 (SIP adjustments)

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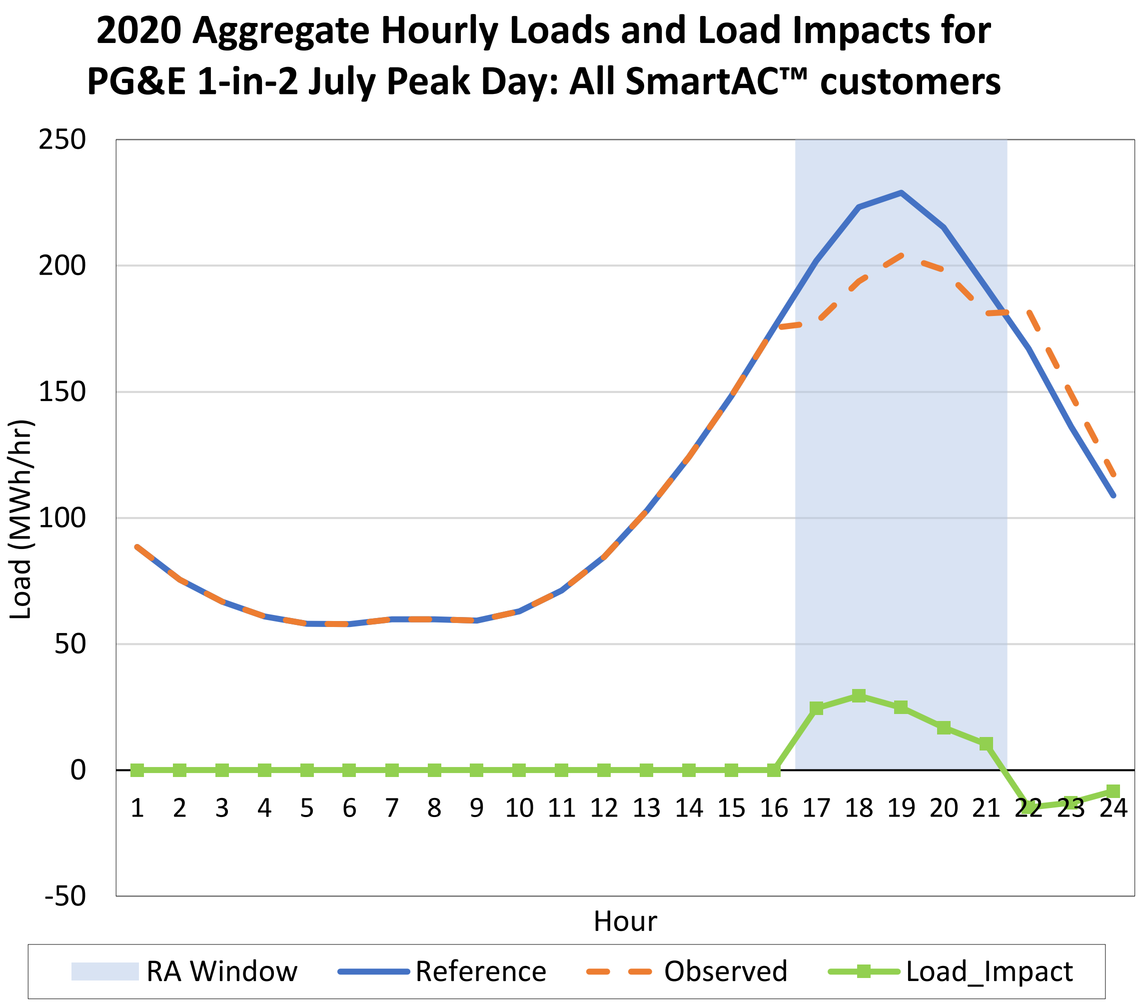
6. *Ex-ante* Load Impacts



- Resource Adequacy window: 4-9 p.m.
- Average RA window load impact: 21.1 MWh/hour (compared to 47.9 MWh/hour from PY19)
- Percent Load Impact: 10% of reference loads (compared to 21 percent from PY19)

Recommendations

- Continued replacement of aging devices with higher-performing two-way devices would
  - increase program load impacts
  - make SmartAC™ a more dependable resource in CAISO wholesale market
- Monitor performance in early season events to identify dispatch issues and remedy for remaining events

Questions?

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2020 SDG&E AC Saver Day Of Load Impact Evaluation

IOU 2021 Load Impact Protocol Workshop

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April 29, 2021

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Agenda

- Program overview
- Ex post methodology
- Ex post results
- Enrollment forecast
- Ex ante methodology
- Ex ante results
- Conclusions

Program Overview

Ex Post Methodology

Ex Post Results

Enrollment Forecast

Ex Ante Methodology

Ex Ante Results

Conclusions

Program Overview

- Day-of demand response program offered to residential and commercial customers
  - Direct load control of central air conditioning (CAC)
  - Switches with one-way communication
- Events can be called on non-holidays from April – October
  - 2 to 4 hours in length
  - 12 PM to 9 PM
  - Maximum of 20 events

Customer Type	Cycling Strategy	Enrolled Customers (Oct. 2020)	% CAC Tonnage Enrolled	Incentive per Ton Enrolled
Residential	50%	6,203	71%	$10.35
	100%	2,028	29%	$27.00
Commercial	30%	684	25%	$4.50
	50%	2,461	75%	$7.50

Event Dates and Times

- 20 events in 2020
  - Called for 49 hours total
  - 11 events from 6 to 8 PM
  - 2 weekend events (#19 and #20)
  - 68 °F to 88 °F mean17 temperatures
  - 71 °F to 98 °F max event window temperatures

Event #	Date	Hour Ending										Mean17 (°F)	Max Event Window Temperature (°F)
		13	14	15	16	17	18	19	20	21	22		
1	6/2/2020							X	X			68	73
2	6/3/2020							X	X			73	76
3	6/10/2020							X	X			76	85
4	6/22/2020								X	X		68	71
5	7/8/2020	X	X									70	79
6	7/9/2020							X	X			68	76
7	7/10/2020							X	X			73	82
8	7/13/2020							X	X			75	78
9	7/27/2020							X	X			70	74
10	7/29/2020							X	X			68	74
11	7/30/2020							X	X	X		70	79
12	7/31/2020						X	X	X			75	84
13	8/14/2020						X	X	X	X		79	90
14	8/17/2020						X	X	X			78	87
15	8/18/2020					X	X	X	X			80	86
16	8/19/2020							X	X			79	85
17	8/21/2020							X	X			78	86
18	8/27/2020							X	X			76	82
19	9/5/2020						X	X	X			82	97
20	9/6/2020						X	X	X			88	98

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Ex Post Methodology

- Reference loads were estimated using a matched control group for both residential and commercial customers
  - Residential customers have traditionally used a RCT framework
  - Paging issues to AC devices prevented the implementation of an RCT for 2020
- Matches were found using a dissimilarity statistic
  - Using peak demand on hot, nonevent days
  - Demand before and after event hours
- Regressions are used to estimate impacts
  - An adjustment is applied to remove treatment and control differences that incorporates nonevent day and morning event day usage

Program Overview

Ex Post Methodology

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Residential Ex Post Results

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- Per site impacts range from 0.01 kW to 0.44 kW
- All residential impacts are statistically significant
- The largest impacts overlap with heatwave emergencies in August and September
  - August 16 – 20 and September 3 – 8
  - 91 °F average max event temperature
  - 0.33 kW average per site impact

Date	Impact			Max Event Window Temperature (°F)	Event Hours	Statistically Significant at 90% Level
	Per CAC Unit (kW)	Per Site (kW)	Aggregate (MW)			
6/2/2020	0.03	0.03	0.24	74	6pm - 8pm	Yes
6/3/2020	0.11	0.12	0.82	76	6pm - 8pm	Yes
6/10/2020	0.18	0.20	1.37	85	6pm - 8pm	Yes
6/22/2020	0.01	0.01	0.09	71	7pm - 9pm	Yes
7/8/2020	0.04	0.05	0.38	80	12pm - 2pm	Yes
7/9/2020	0.04	0.05	0.38	77	6pm - 8pm	Yes
7/10/2020	0.15	0.17	1.27	83	6pm - 8pm	Yes
7/13/2020	0.15	0.17	1.29	79	6pm - 8pm	Yes
7/27/2020	0.04	0.05	0.38	75	6pm - 8pm	Yes
7/29/2020	0.04	0.05	0.35	74	6pm - 8pm	Yes
7/30/2020	0.07	0.08	0.60	79	6pm - 9pm	Yes
7/31/2020	0.17	0.20	1.47	85	5pm - 8pm	Yes
8/14/2020	0.18	0.21	1.26	91	5pm - 9pm	Yes
8/17/2020	0.21	0.23	1.48	88	5pm - 8pm	Yes
8/18/2020	0.26	0.29	1.84	87	4pm - 8pm	Yes
8/19/2020	0.22	0.26	1.61	85	6pm - 8pm	Yes
8/21/2020	0.18	0.21	1.31	87	6pm - 8pm	Yes
8/27/2020	0.18	0.20	1.27	83	6pm - 8pm	Yes
9/5/2020	0.39	0.44	3.02	98	5pm - 8pm	Yes
9/6/2020	0.37	0.42	2.89	99	5pm - 8pm	Yes
Average*	**0.12**	**0.13**	**0.94**	**80**	**6pm - 8pm**	**Yes**

*Green rows reflect the average 6-8PM weekday 2020 AC Saver Day Of event

Orange rows are weekend events

Commercial Ex Post Results

- Per site impacts range from 0.00 kW to 0.21 kW
- Event days called during business hours have larger impacts (before 6 PM)

Date	Impact			Max Event Window Temperature (°F)	Event Hours	Statistically Significant at 90% Level
	Per CAC Unit (kW)	Per Site (kW)	Aggregate (MW)			
6/2/2020	0.02	0.05	0.17	73	6pm - 8pm	Yes
6/3/2020	0.01	0.03	0.10	75	6pm - 8pm	No
6/10/2020	0.03	0.07	0.24	85	6pm - 8pm	Yes
6/22/2020	0.01	0.02	0.06	70	7pm - 9pm	No
7/8/2020	0.05	0.12	0.34	78	12pm - 2pm	Yes
7/9/2020	0.02	0.04	0.13	76	6pm - 8pm	Yes
7/10/2020	0.03	0.07	0.20	82	6pm - 8pm	Yes
7/13/2020	0.02	0.05	0.15	78	6pm - 8pm	Yes
7/27/2020	0.01	0.03	0.09	74	6pm - 8pm	Yes
7/29/2020	0.02	0.05	0.16	73	6pm - 8pm	Yes
7/30/2020	0.02	0.05	0.15	78	6pm - 9pm	Yes
7/31/2020	0.03	0.06	0.19	82	5pm - 8pm	Yes
8/14/2020	0.05	0.12	0.36	89	5pm - 9pm	Yes
8/17/2020	0.07	0.16	0.53	86	5pm - 8pm	Yes
8/18/2020	0.09	0.21	0.68	85	4pm - 8pm	Yes
8/19/2020	0.04	0.09	0.31	84	6pm - 8pm	Yes
8/21/2020	0.01	0.03	0.11	85	6pm - 8pm	No
8/27/2020	0.00	0.01	0.04	81	6pm - 8pm	No
9/5/2020	0.00	0.00	-0.01	96	5pm - 8pm	No
9/6/2020	0.03	0.08	0.24	96	5pm - 8pm	Yes
Average*	**0.02**	**0.05**	**0.15**	**79**	**6pm - 8pm**	**Yes**

*Green rows reflect the average 6-8PM weekday 2020 AC Saver Day Of event

Orange rows are weekend events

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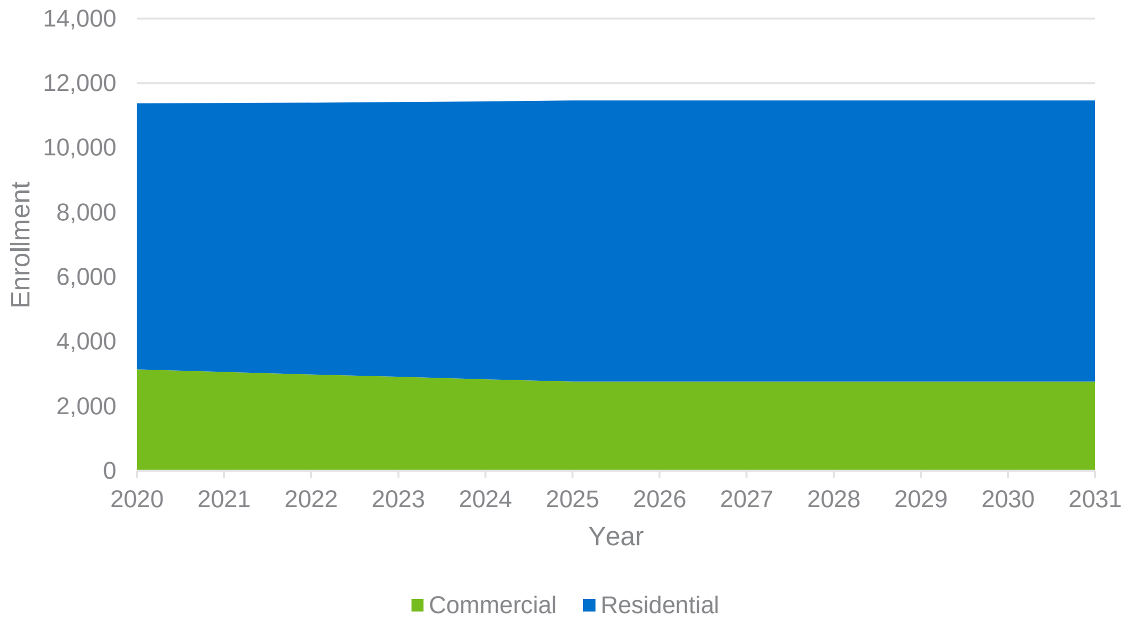
Enrollment Forecast

- Modest enrollment gains are expected for residential customers
- Slight decreases are expected for commercial customers
- Overall program customer count is forecasted to be relatively stable
- Enrollment forecast is static in 2025 and beyond



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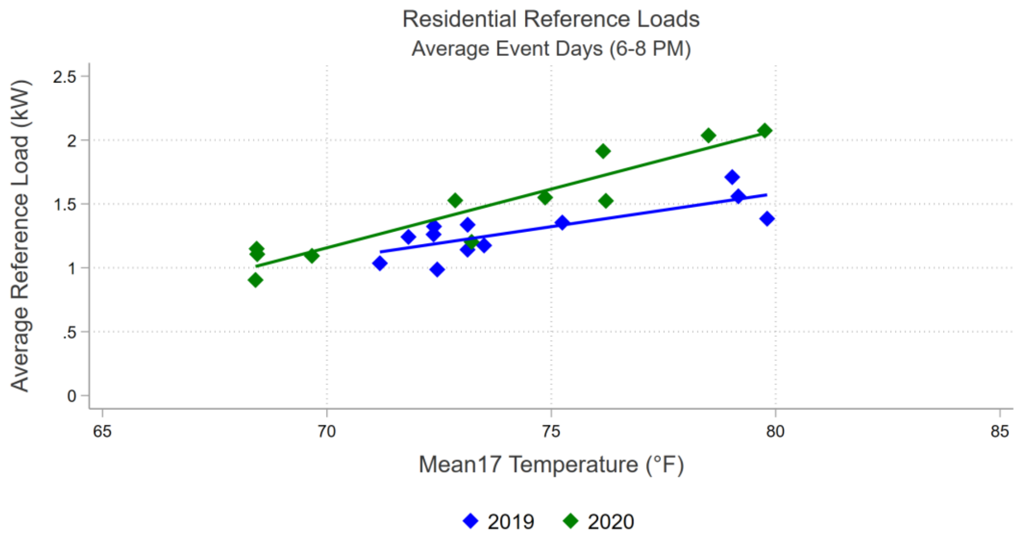
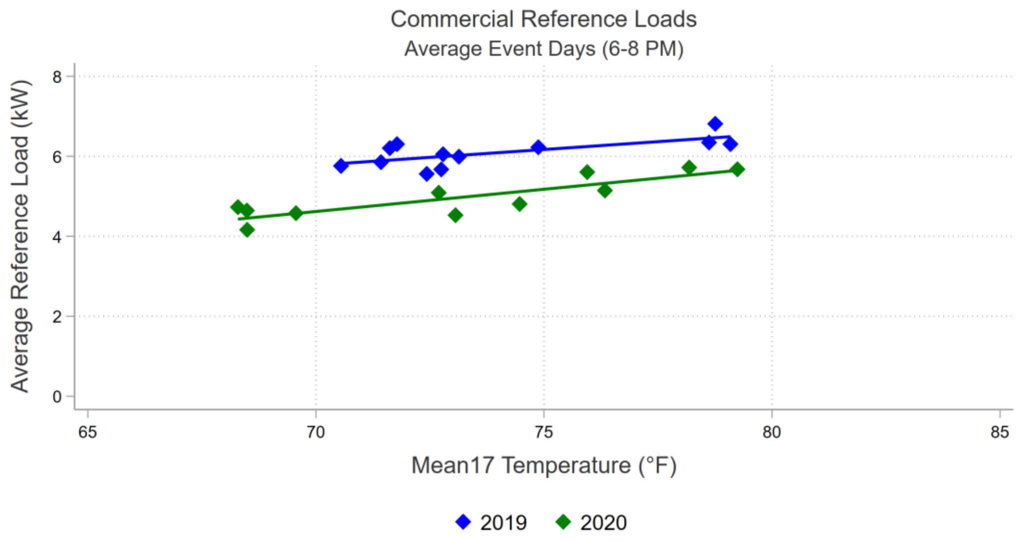
Ex Post Recap 2019 vs 2020 – Reference Load

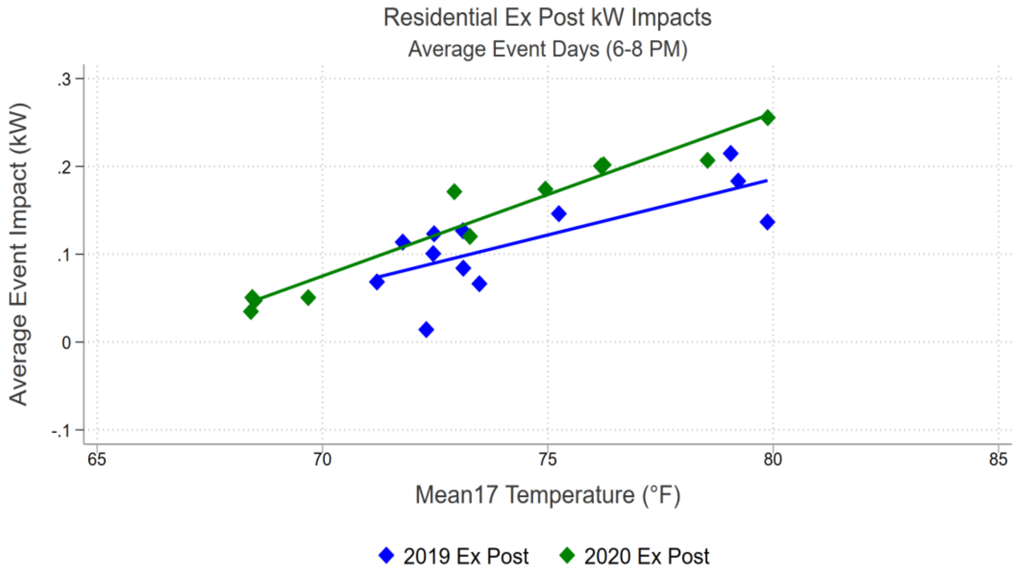
- COVID-19 changed reference loads for customers between 2019 and 2020 for the average event (6 PM to 8 PM)
  - Higher for residential customers – working from home
  - Lower for commercial customers – businesses running partial operations

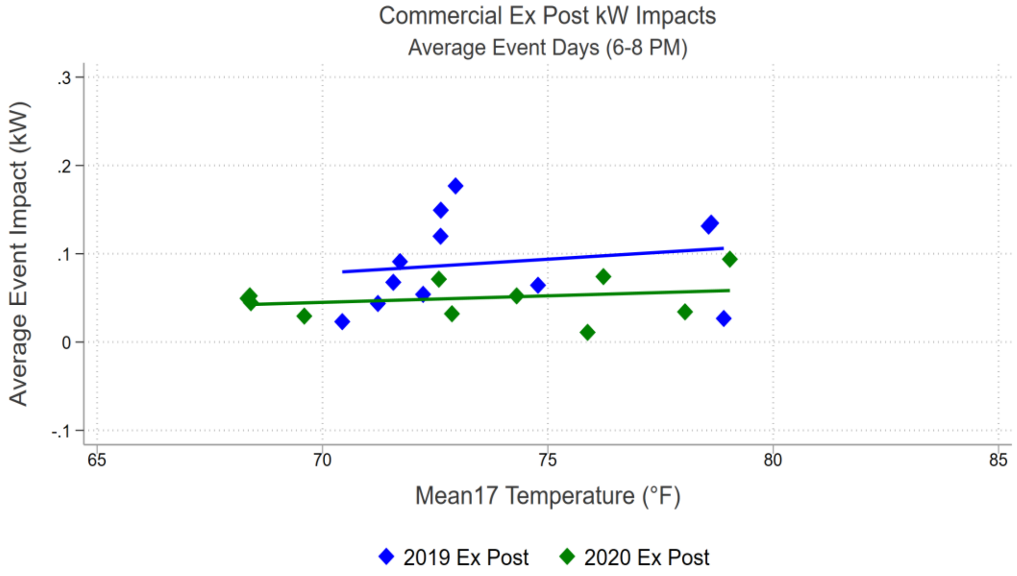




Ex Post Recap 2019 vs 2020 – kW Impacts

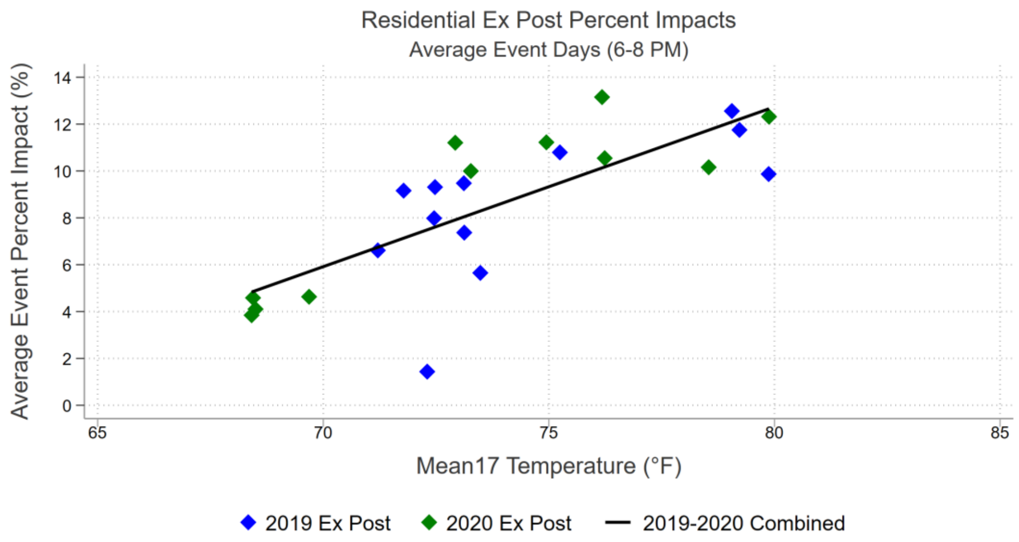
- Changes in reference load led to differences in ex post kW impacts
  - Residential – Higher reference loads meant larger impacts in 2020
  - Commercial – Lower reference loads meant lower impacts in 2020

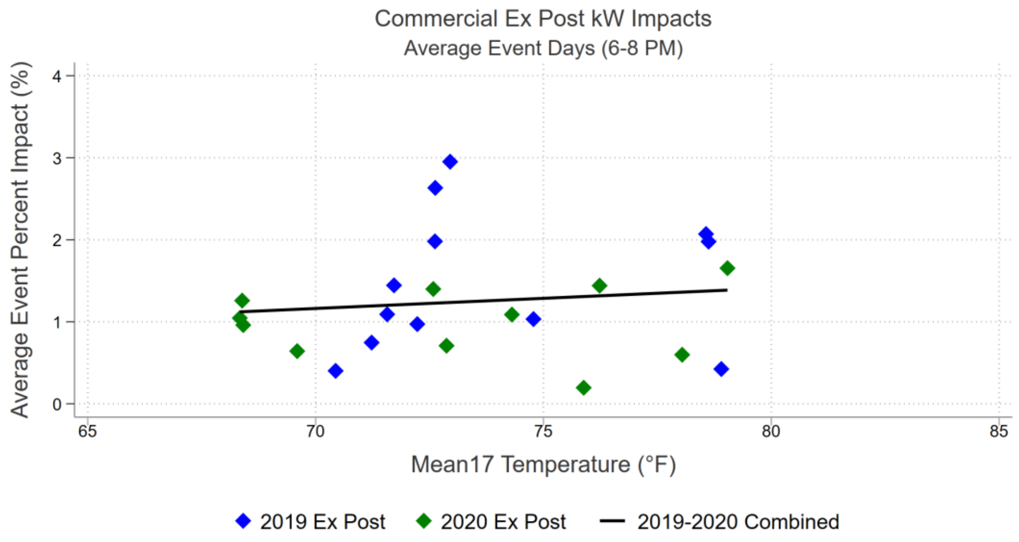




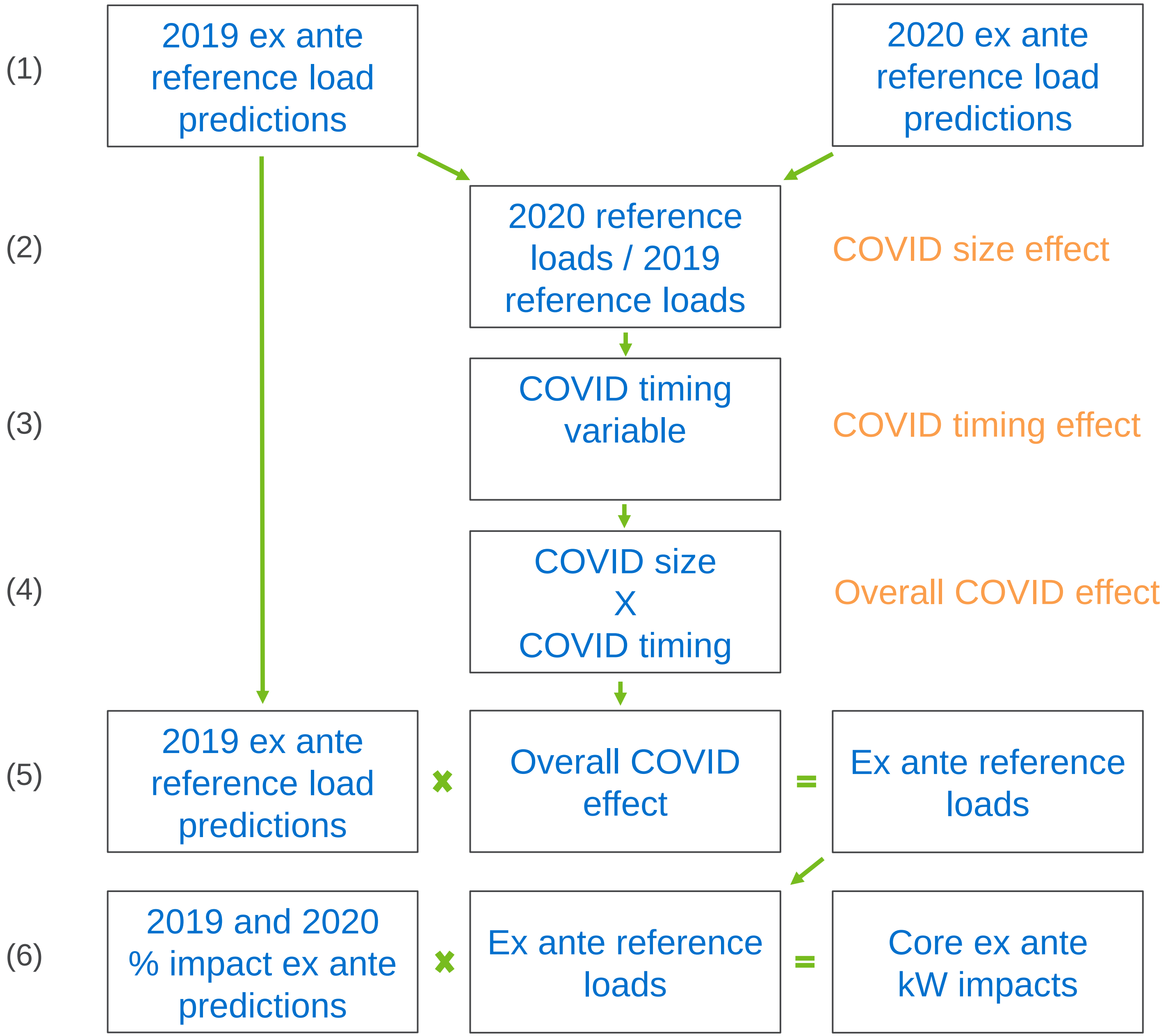
Ex Post Recap 2019 vs 2020 – Percent Impacts

- In percentage terms the impacts remained comparable
- These regressions and the reference load regressions are used in ex ante





Ex Ante Methodology



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Ex Ante Results – SDG&E 1-in-10 August Typical Event Day

- Reference loads change for 2022 after COVID-19 adjustment period ends
  - Residential loads decrease
  - Commercial loads increase
- Aggregate impacts are also driven by changes in enrollment

Customer Type	Year	Reference Load (kW)	Per Premise Impact (kW)	Percent Impact	Enrollment	Aggregate Impact (MW)
Residential	2021	1.82	0.23	12.6%	8,320	1.88
	2022	1.60	0.20	12.5%	8,412	1.67
	2023	1.60	0.20	12.5%	8,507	1.69
	2024	1.60	0.20	12.5%	8,605	1.70
Commercial	2021	6.0	0.10	1.7%	3,065	0.30
	2022	6.26	0.10	1.6%	2,987	0.30
	2023	6.26	0.10	1.6%	2,912	0.30
	2024	6.26	0.10	1.6%	2,838	0.29

Ex Ante Comparison – SDG&E 1-in-10 August Typical Event Day

- Comparison between previous and current year evaluations
- Differences are relatively small
  - Per-premise impacts slightly decrease because of COVID-19 affecting reference loads
- Changes in forecasted enrollment change aggregate impact

Customer Type	Forecast Year	Evaluation Year	Per-Premise Impact (kW)	Enrollment	Aggregate Impact (MW)
Residential	2021	2019	0.26	6,971	1.82
		2020	0.23	8,320	1.88
Commercial	2021	2019	0.13	3,452	0.44
		2020	0.10	3,065	0.30

Program Overview

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Ex Ante Results

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Conclusions

- Ex Post
  - COVID-19 affected reference loads for both residential and commercial customers
  - The largest impacts for residential customers were produced during heatwaves
  - Commercial customers had the biggest impacts when called during business hours

- Ex Ante
  - Change in reference loads and COVID-19 led to a change in methodology
  - COVID-19 timing variable extends through 2022

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Load Impact Evaluation: *Base Interruptible Program*

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6. *Ex-ante* Load Impacts

1. BIP Program Description

- Emergency DR program for non-residential customers, events triggered by CAISO or local system emergencies
- Customers receive a monthly capacity credit in exchange for a commitment to reduce energy consumption to their Firm Service Level (FSL)
  - The FSL represents the customer's minimal operational requirements
- 15 or 30-minute notice of events
- Failure to reduce load to the FSL can result in excess energy charges, an increase in the FSL (and commensurate reduction in capacity credits), re-test events, or de-enrollment from the program
- Program specifics vary by utility

2. *Ex-post* Methodology

- Individual regressions were used to estimate BIP *ex-post* load impacts
- This method was chosen for two reasons:
  - Difficulty in finding adequate control-group customers
  - Some customers have volatile loads, so even customers that match reasonably well on average may not have a comparable load on a specific day

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- Customer-specific specification search conducted to:
  - Determine whether each customer has a weather-sensitive load
  - Find the best fitting weather and shape variables by groups defined by weather sensitivity and industry group

2. *Ex-post* Methodology (2)

- BIP **load impacts** do not tend change significantly with temperatures because the biggest responders do not have weather-sensitive loads
- However, there are weather-sensitive customers in BIP that cause the program **reference load** to change somewhat with temperatures
- Separate **weekday** versus **weekend** regression specifications are used

3. *Ex-post* Load Impacts:
Events

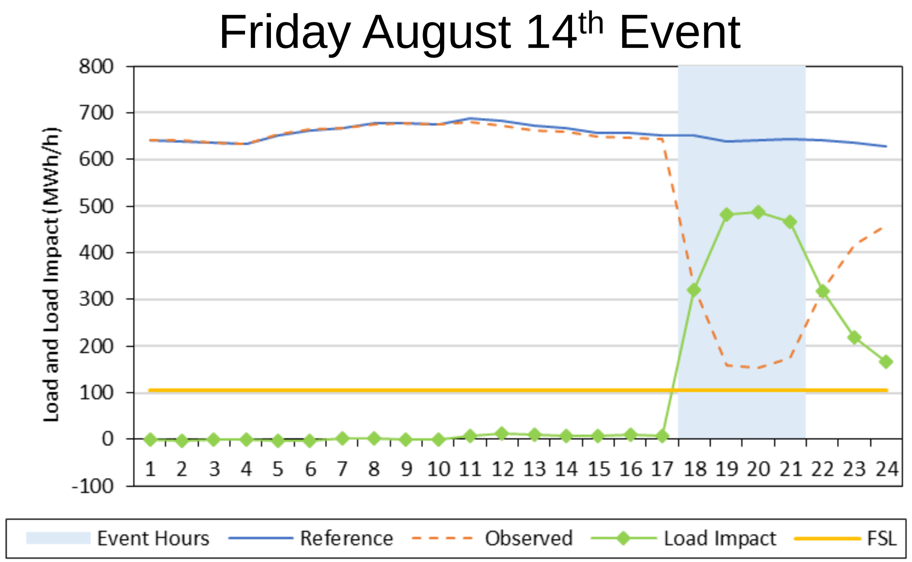
Date	Day of Week	PG&E	SCE	SDG&E
8/14/2020	Friday	Emergency Event 5:02 - 10:47 p.m.	CAISO Stage 2 Emergency 5:10 - 8:35 p.m.	Temp. & Sys. Load 6:00 - 8:00 p.m.
8/15/2020	Saturday	Emergency Event 3:45 - 8:45 p.m.	CAISO Warning 3:00 - 7:45 p.m.	
8/16/2020	Sunday	Emergency Event 7:15 - 7:59 p.m.	CAISO Warning 5:40 - 7:25 p.m.	
8/17/2020	Monday	Emergency Event 3:47 -7:47 p.m.	CAISO Stage 2 Emergency 3:10 - 7:40 p.m.	Temp. & Sys. Load 3:00 - 7:00 p.m.
8/18/2020	Tuesday	Emergency Event 2:17 - 7:32 p.m.	CAISO Warning 1:40 - 7:25 p.m.	Temp. & Sys. Load 7:00 - 8:00 p.m.
8/19/2020	Wednesday			Temp. & Sys. Load 6:00 - 8:00 p.m.
8/20/2020	Thursday			Temp. & Sys. Load 6:00 - 8:00 p.m.
9/5/2020	Saturday	Emergency Event 6:30 - 8:34 p.m.	CAISO Warning 5:30 - 8:25 p.m.	
9/6/2020	Sunday	Emergency Event 5:17 - 9:00 p.m.	CAISO Warning 4:40 - 8:22 p.m.	
9/7/2020	Monday		SCE - Local Reliability 4:05 - 7:33 p.m.	

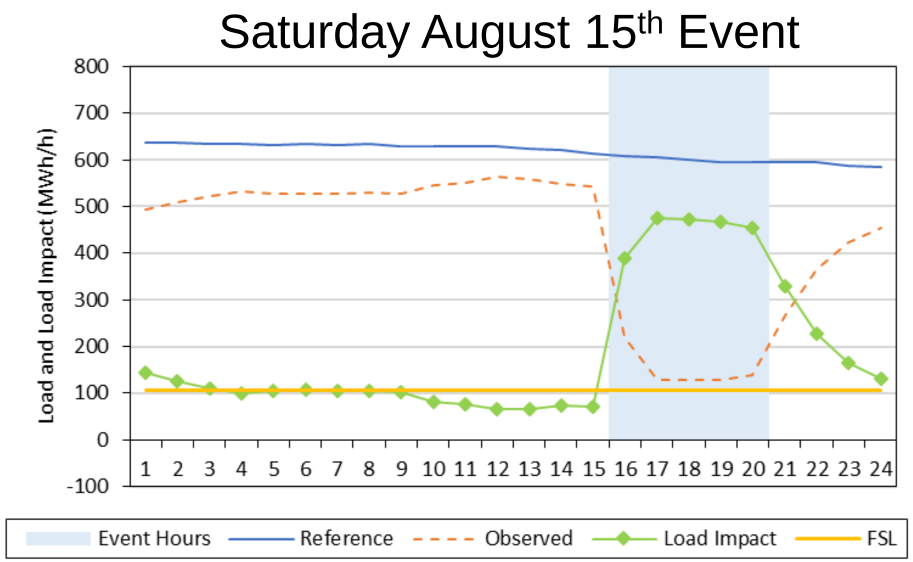
- The SCE 9/6 event was accidentally terminated at 6:04 p.m. and restarted and stopped multiple times after, with the final termination coming at 8:22 pm. No EEC after 6:04 p.m. termination.
- The SCE 9/7 event was called for Block 404 only.

3. *Ex-post* Load Impacts:
Events (2)

Utility	Hours of Availability	Hours of Actual Use	No. of Available Dispatches	No. of Actual Dispatches
PG&E	180 / year 4 / day	26.52	10 / month 1 / day	7
SCE	180 / year 6 / day	28.01	10 / month 1 / day	8
SDG&E	120 / year 4 / day	11	10 / month	5

3. *Ex-post* Load Impacts:
SCE *Consecutive Event Days*





- Morning load usage helps identify customer’s reference loads.
- Observed morning loads on consecutive events were lower when compared to similar non-event days.
- Morning loads not used when estimating consecutive event day load impacts.
  - This leads to differences between pre-event reference and observed loads. As a result, a difference is created between the estimated event-hour load impacts and the within-day load drop that can be seen in metered data.

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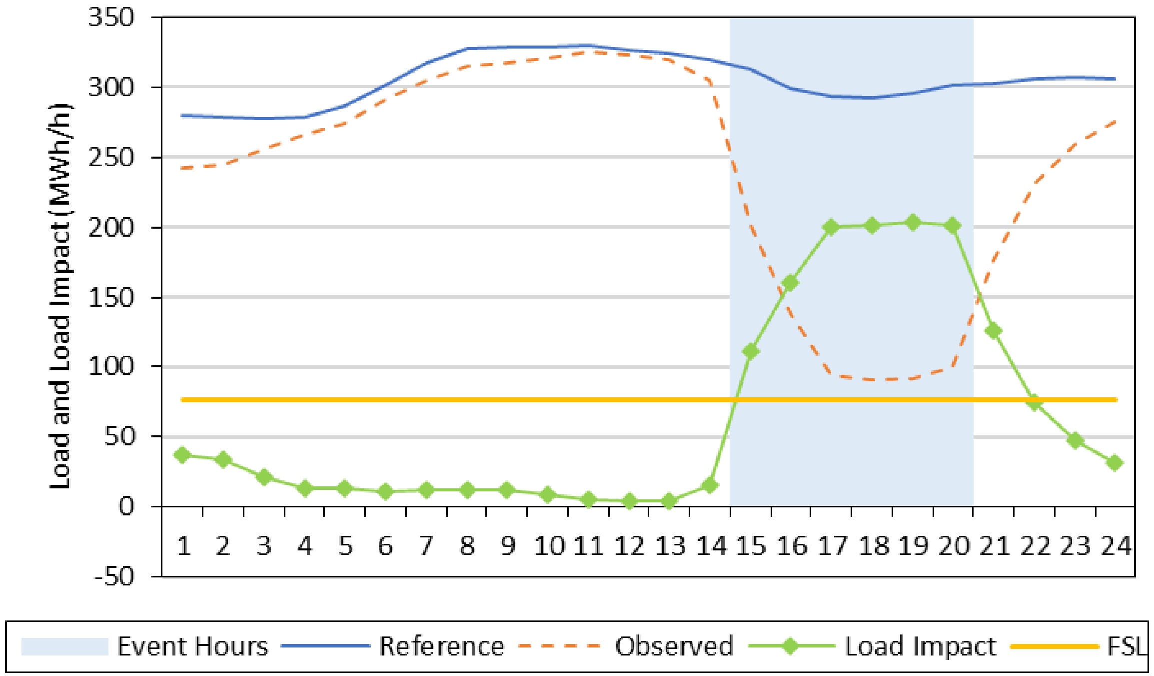
3. *Ex-post* Load Impacts:
PG&E Typical Event Day



- Event from 2:00 to 8:00 p.m.
  (Results over common event hours 4-7 p.m.)
- 482 called customers
- Ref. Load = 294 MW
- Load Impact = 202 MW
- % Load Impact = 69%
- FSL = 76 MW
- FSL Achievement = 93%
- Top 15 responders account for 50% of the total load impact

Note: PG&E Typical Event Day represented by August 17^{th} and 18^{th} event days.

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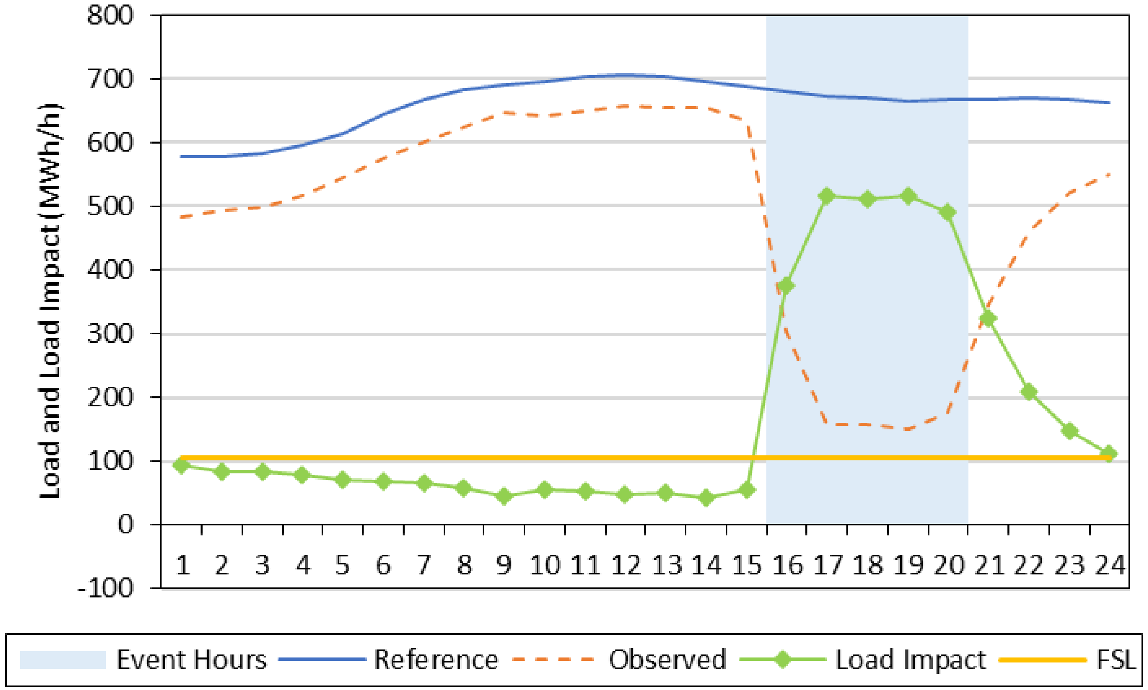
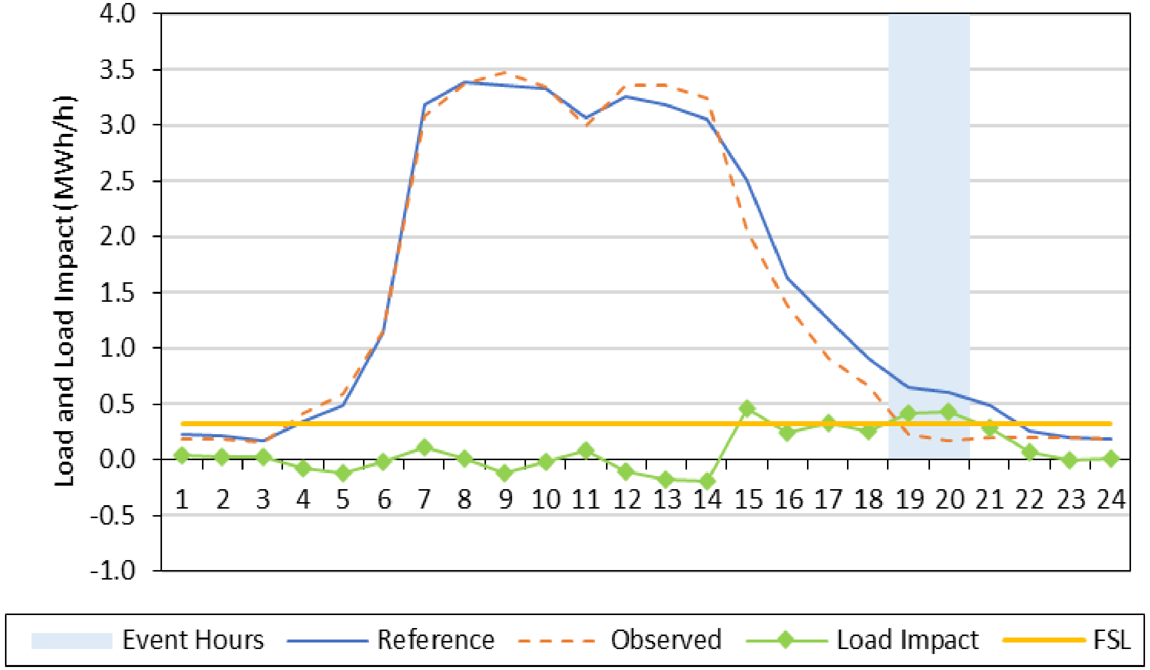
3. *Ex-post* Load Impacts:
SCE Typical Event Day



- Event from 3:10 to 7:40 p.m.
  (Results over full event hours 4-7 p.m.)
- 469 called customers
- Ref. Load = 670 MW
- Load Impact = 514 MW
- % Load Impact = 77%
- FSL = 105 MW
- FSL Achievement = 91%
- Top 20 responders account for 58% of the total load impact

Note: SCE Typical Event Day represented by August 17th.

3. *Ex-post* Load Impacts:
SDG&E Typical Event Day



- Event from 6:00 to 8:00 p.m.
- 4 enrolled customers
- Avg. Ref. Load = 0.6 MW
- Avg. Load Impact = 0.4 MW
- % Load Impact = 68%
- FSL = 0.3 MW
- FSL Achievement = 139%
- Reference load drops during event hours, so there's little need for customer response by the later event hours

Note: SDG&E Typical Event Day represented by August 14th, 19th, and 20th event days.

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4. *Ex-ante* Methodology

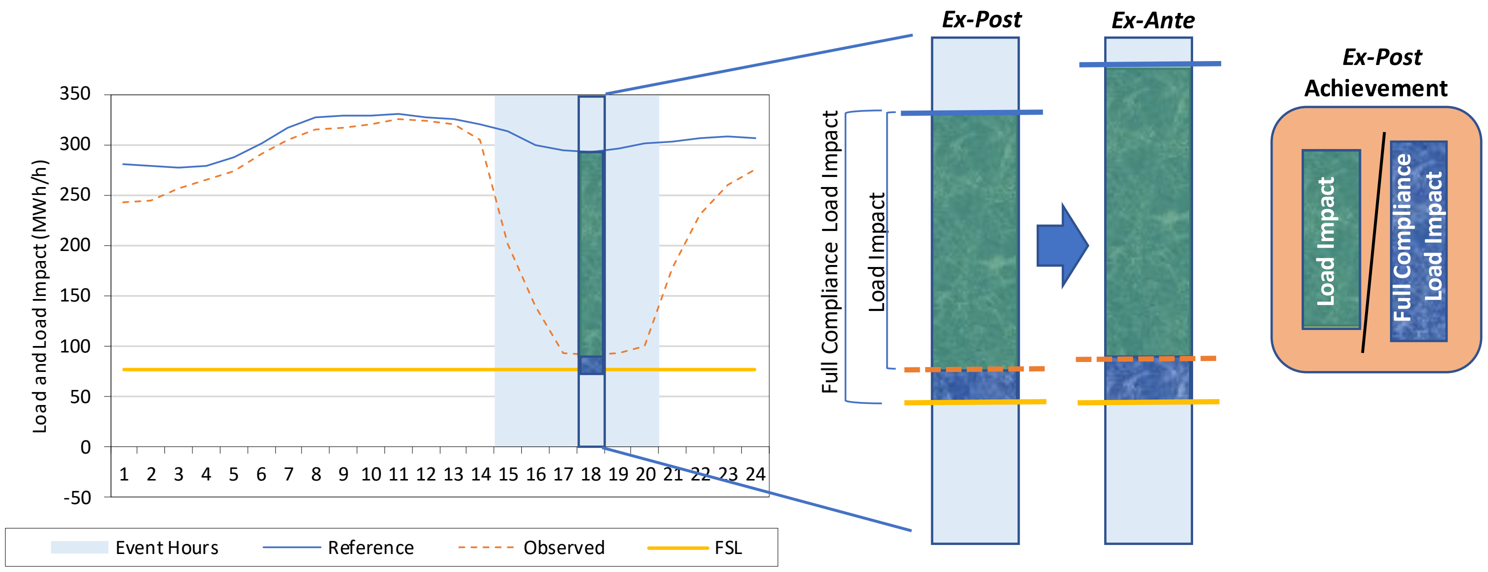
- Customers who have left BIP are not included

- Reference loads are simulated using the following:
  - Customer-specific regressions to obtain effect of weather and time-period indicators on usage
  - *Ex-ante* day types and weather conditions (*e.g.*, August peak month day in a utility-specific 1-in-2 weather year)
  - Biggest responders do not tend to have weather-sensitive loads

- *Ex-ante* load impacts are based on the most recent full or test / M&E event day for which customer's reference load was above their FSL, by customer

4. *Ex-ante* Methodology (2)

- Each customer's *ex-ante* load impact is set to its *ex-post* FSL achievement rate:
  - *ExPost* Achievement = *ExPost* Load Impact / (Ref. – FSL)
  - *ExAnte* Impact = *ExPost* Achievement x (Ref. – FSL)



- Load impact is zero if FSL is above the reference load
- Customers who have joined BIP are assigned the program-level FSL achievement rate (applied to their own reference loads and FSL, if available)
- Load impacts display little to no relationship with weather conditions

Note: Example is provided for aggregate load; actual methodology is done at the per-customer level.

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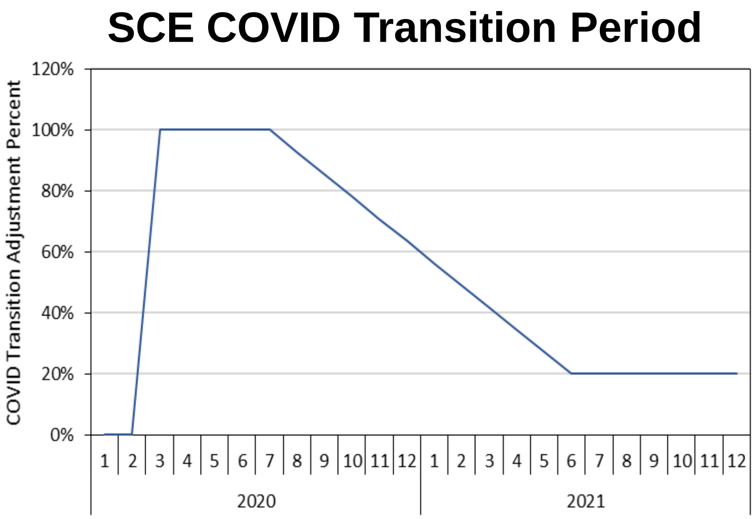
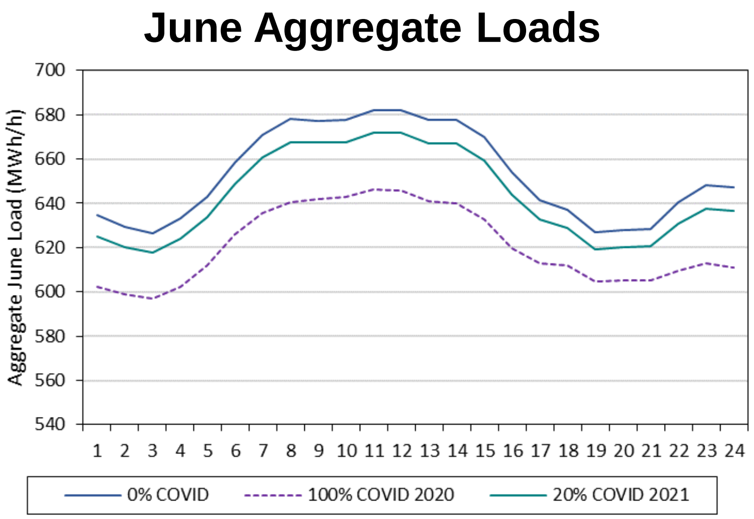
4. *Ex-ante* Methodology (3)

- Reference loads are adjusted for COVID
  1. Estimate hourly per-customer COVID effects via regressions
  2. Make assumption regarding COVID transition period
  3. Apply per-customer COVID effect to reference loads based on the transition period



Note: 2022-2031 COVID adjustment = 0%



Reduced Load due to COVID
SCE: 43 MW
PG&E: 12 MW
SDG&E: 0.3 MW

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5. Enrollment Forecast

- The table below shows August enrollment in each year of the forecast
  - PG&E forecasts flat enrollment
  - SCE forecasts a slight increase in enrollment
  - SDG&E forecasts a small increase in enrollment

Utility	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
PG&E	308	308	308	308	308	308	308	308	308	308	308
SCE 15-min	46	47	48	49	50	51	52	53	54	55	56
SCE 30-min	305	312	319	326	333	340	347	354	361	368	375
SDG&E	5	6	7	8	9	9	9	9	9	9	9

6. *Ex-ante* Load Impacts:

by Year and Weather Scenario

PG&E

Year	Weather	# SAIDs	Load Impact (MW)	Temp. (°F)	FSL (MW)
Aug. 2021	PG&E 1-in-2	308	183	93	56
	PG&E 1-in-10		184	96	
Aug. 2031	PG&E 1-in-2	308	193	93	56
	PG&E 1-in-10		194	96	

SCE

Year	Weather	# SAIDs	Load Impact (MW)	Temp. (°F)	FSL (MW)
Aug. 2021 (50% COVID)	SCE 1-in-2	351	490	88	109
	SCE 1-in-10		493	93	
Aug. 2031 (0% COVID)	SCE 1-in-2	431	628	88	134
	SCE 1-in-10		631	93	

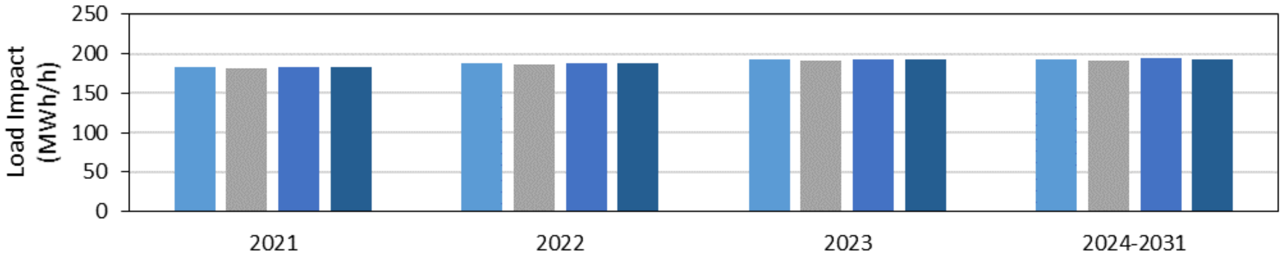
SDG&E

Year	Weather	# SAIDs	Load Impact (MW)	Temp. (°F)	FSL (MW)
Aug. 2021 (56% COVID)	SDG&E 1-in-2	5	0.8	87	0.4
	SDG&E 1-in-10		0.8	90	
Aug. 2031 (0% COVID)	SDG&E 1-in-2	9	1.5	87	0.7
	SDG&E 1-in-10		1.5	90	

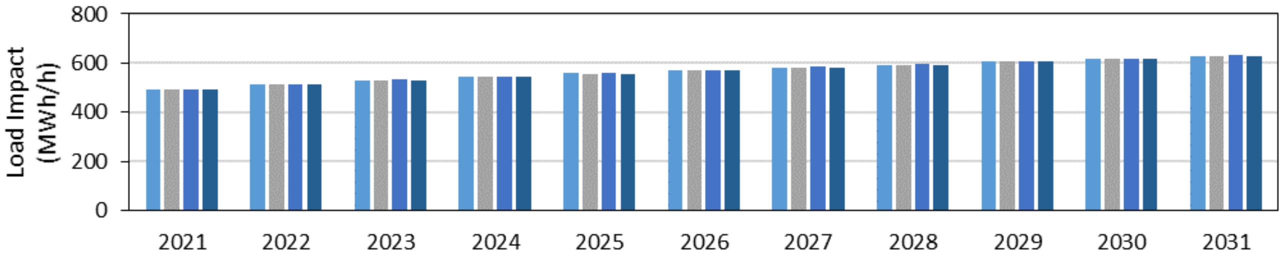
6. *Ex-ante* Load Impacts:

by Year and Weather Scenario (2)

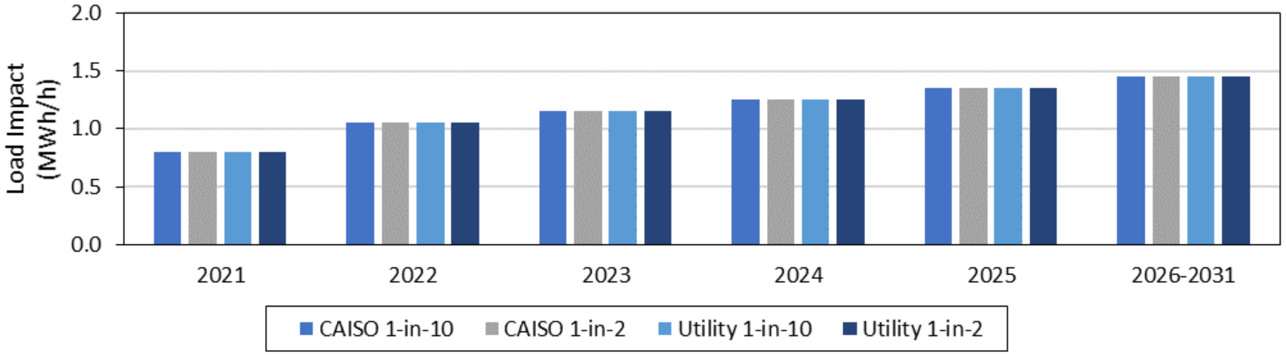
PG&E



SCE



SDG&E



Note: Aggregate load impacts above are for the month of August

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6. *Ex-ante* Load Impacts:

PG&E Ex-Post vs. Ex-Ante

Ex Post / Ex Ante	Date / Scenario	# SAIDs	Reference Load (MW)	Load Impact (MW)	Temp. (°F)	FSL (MW)	FSL Achievement
Ex-Post	Typical Event Day	482	294	202	98	76	93%
Ex-Ante	August 2021 Typical Event Day	308	234	183	93	56	102%

- Total load impact decreases as enrollment decreases
- Per-customer reference loads, load impacts, and FSL Achievement larger in *ex-ante* because of customers that remained on the program
- Per-customer references loads slightly higher in *ex-ante* as COVID adjustment assumption is reduced

Note: All *ex-ante* forecasts from this point forward reflect the utility-specific 1-in-2 peak day

6. *Ex-ante* Load Impacts:

SCE Ex Post vs. Ex Ante

Ex Post / Ex Ante	Date / Scenario	# SAIDs	Reference Load (MW)	Load Impact (MW)	Temp. (°F)	FSL (MW)	FSL Achievement
Ex-Post	Typical Event Day	469	670	514	94	105	91%
Ex-Ante	August 2021 Typical Event Day	351	629	490	88	109	94%

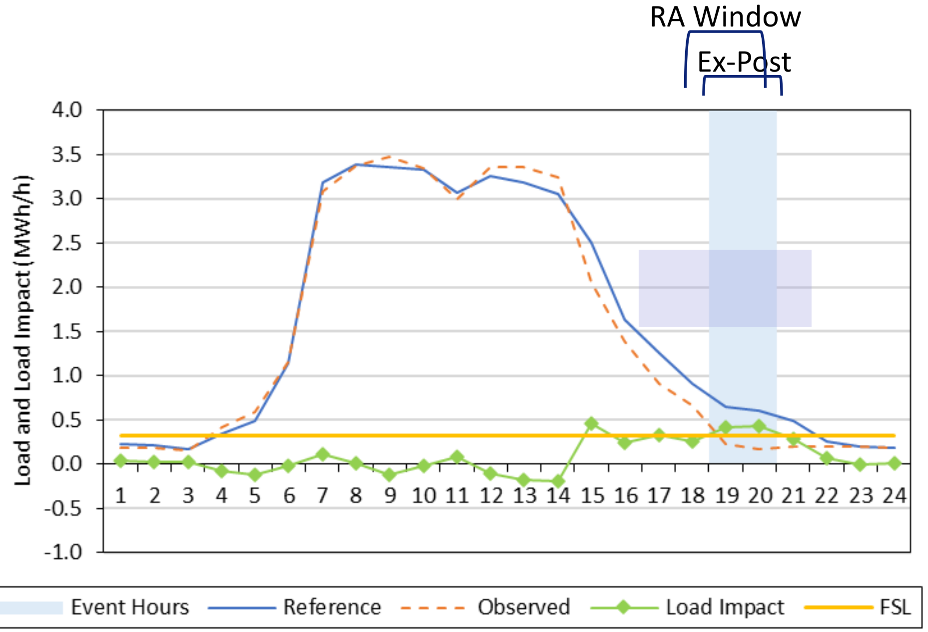
- Compositional Changes:
  - 128 customers left, with average 0.61 MW reference load, 0.15 MW load impact, and 30% FSL Achievement
  - 341 customers stayed, with average 1.7 MW reference load, 1.45 MW load impact, and 99% FSL Achievement
  - 2 new customers with remaining 8 from enrollment forecast
- Per-customer reference loads, load impacts, and FSL Achievement larger in *ex-ante* because of customers that remained on the program
- Per-customer references loads slightly higher as COVID adjustment assumption is reduced

6. *Ex-ante* Load Impacts:

SDG&E Ex Post vs. Ex Ante

Ex Post / Ex Ante	Date / Scenario	# SAIDs	Reference Load (MW)	Load Impact (MW)	Temp. (°F)	FSL (MW)	FSL Achievement
Ex-Post	Typical Event Day	4	0.6	0.4	83	0.3	139%
Ex-Ante	August 2021 Typical Event Day	5	1.2	0.8	87	0.4	97%

- Differences are primarily due to program reference load dropping off in later hours
    - *Ex-post* event hours:
      HE 19 to 20 (6 to 8 p.m.)
    - *Ex-ante* RA window
      HE 17 to 21 (4 to 7 p.m.)
- As a result, there's a lot less load to curtail during the ex-post event window



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6. *Ex-ante* Load Impacts:

PG&E, Previous vs. Current Typical Event Day 2021

When Created	# SAIDs	Aggregate			Per-customer	
		Reference Load (MW)	Load Impact (MW)	FSL (MW)	Reference Load (kW)	Load Impact (kW)
Following PY2019 (Previous)	512	334	236	82	652	461
Following PY2020 (Current)	308	234	183	56	761	593

- Reference load and load impact decreased by 99.5 MW and 53.5 MW, respectively
  Factors include (arrows indicate direction of load impact):
  - Enrollment forecast decreased by 204 customers
  - Reference loads adjusted for COVID of remaining customers (~12 MW reduction)
  - FSL decreased from 82 MW to 56 MW
  - FSL Achievement rate increased from 94% to 102%

- Per-customer reference load and load impacts higher
  - COVID adjustments leads to smaller reference loads; however,
  - customers that remained are larger, on average.

6. *Ex-ante* Load Impacts:

SCE, Previous vs. Current Typical Event Day 2021

When Created	# SAIDs	Aggregate			Per-customer	
		Reference Load (MW)	Load Impact (MW)	FSL (MW)	Reference Load (kW)	Load Impact (kW)
Following PY2019 (Previous)	452	690	541	95	1,526	1,197
Following PY2020 (Current)	351	627	488	109	1,786	1,391

- Reference load and load impact decreased by 63 MW and 53 MW, respectively
  Factors include (arrows indicate direction of load impact):
  - Enrollment forecast decreased by 101 customers
  - Reference loads adjusted for COVID of remaining customers (~22 MW reduction)
  - FSL increased from 95 MW to 109 MW
  - FSL Achievement rate increased from 91% to 94%

- Per-customer reference load and load impacts higher
  - COVID adjustments leads to smaller reference loads; however,
  - customers that remained are larger, on average.

6. *Ex-ante* Load Impacts:

SDG&E, Previous vs. Current Typical Event Day 2020

When Created	# SAIDs	Aggregate			Per-customer	
		Reference Load (MW)	Load Impact (MW)	FSL (MW)	Reference Load (kW)	Load Impact (kW)
Following PY2018 (Previous)	6	1.6	1.0	0.5	264	244
Following PY2019 (Current)	5	1.2	0.8	0.4	244	160

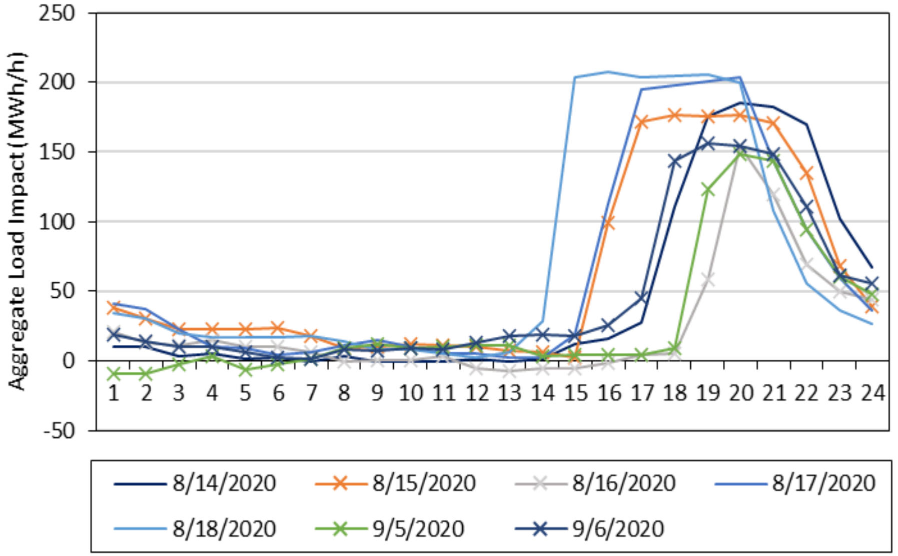
- One fewer enrolled service account assumed in the current forecast
- Lower per-customer loads and load impacts due to COVID adjustment to reference loads

Questions?

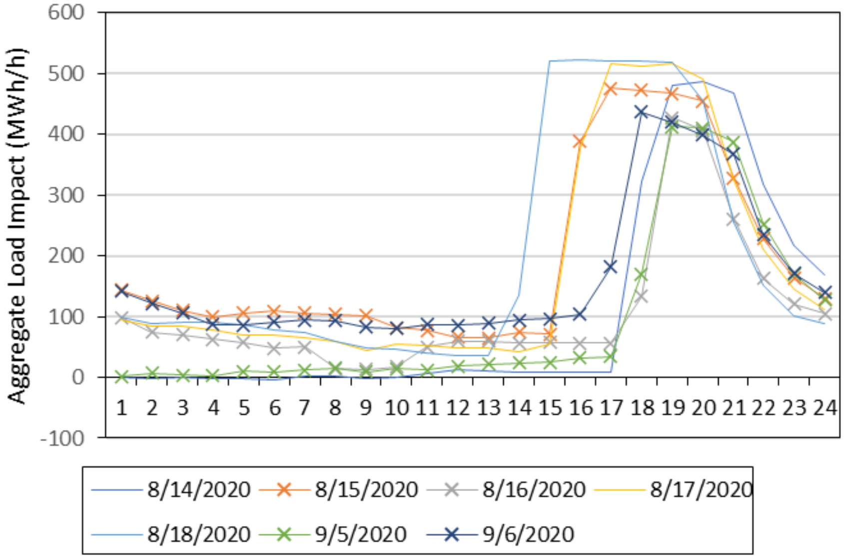
- Contact – Mike Clark,
  Christensen Associates Energy Consulting
  Madison, Wisconsin
  - mtclark@CAEnergy.com
  - (608)231-2266

Appendix:
2020 Load Impacts by Event Day

PG&E



SCE



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AEG
APPLIED ENERGY GROUP

LI Evaluation of California Capacity Bidding Programs

Date: April 29, 2021

Prepared for: 2021 DRMEC Load Impact Workshop

VISION DSM

Agenda

Program Descriptions

- Overall Description
- Descriptions by IOU
- Expected Changes

Ex-Post Load Impacts

- Event Summary
- Load Impacts by IOU

Ex-Ante Load Impacts

- Methodology
- Load Impacts by IOU

Key Findings

- PY2020 Takeaways

Program Descriptions

Program Description

Program Basics

- Statewide aggregator-managed DR program
- Offered by PG&E, SCE, and SDG&E
- Operates May-Oct (PG&E and SDG&E) or year-round (SCE)

Participant Eligibility

- Participants must meet eligibility requirements specific to each IOU program.
- Non-Residential customers (all IOUs)
- Residential customers (currently only through PG&E)
- Dual enrollment is allowed in energy-only program with a different notification type.

Capacity Payments

- Participants receive monthly capacity payments based on nominated load + energy payments based on kWh reductions during events.
- Capacity payments may be adjusted based on performance.
- Participants receive the full monthly capacity payment according to their nomination if no events called for that month.

Program Description by IOU

	PG&E	SCE	SDG&E
Products	Prescribed DA, Elect DA, Elect+ DA	Day Ahead, Day Of	Day Ahead, Day Of
Operating Hours	1 PM – 9 PM	3 PM – 9 PM	11 AM – 7 PM, 1 PM – 9 PM
Event Trigger	CAISO Market Awards	CAISO Market Awards	CAISO Market Awards
Eligible Days	May – October non-holiday weekdays	Year-round non-holiday weekdays	May – October non-holiday weekdays
Event duration	1-4 hours, 2-6 hours, or 1-24 hours	1-6 hours	2-4 hours
Event day limit	5 events per month	5 events per month	6 events per month
Event hour limit	30 hours per month	30 hours per month	24 hours per month

Program Changes

PG&E

- Effective March 8, 2021:
  - Implement a 5-in-10 baseline for residential customers.
  - Change the nomination deadline to the 15^{th} of the month prior to the operating month.
  - Change the bidding deadline for Elect and Elect+ to three days before trade day.
  - Remove the 100 kW per sub-LAP requirement for resource nomination.
- Pending approval:
  - Option for resources to participate on weekends
  - Increase event day limit to six days per month.

SCE

- No changes to Non-Residential.
- Proposing Residential CBP to be implemented as a full program with a 5-in-10 baseline.

SDG&E

- No changes to Non-Residential.
- Proposing to Residential CBP to be implemented as a pilot.

Note on Confidentiality

- A lot of the impacts for PG&E and SCE continue to be confidential.
- Redactions are compliant with the 15/15 Rule *(PUC § 583 D. 14-05-016).*
  - Fewer than 15 customers in a group or subgroup
  - One customer makes up more than 15% of the total load in a group or subgroup
- Information is also redacted if there is only one aggregator in the group or subgroup *(General Order 66-C, Section 2.2(b) D.06-06-066).*
- The purpose of the redactions is to protect customer and/or aggregator confidentiality.
- SDG&E shows all program level impacts.
  - This is a result of guidance from SDG&E attorneys concluding that program level impacts are not confidential.

Ex-Post Load Impacts

Summer Event Day Summary

Utility	Program	Event Days Dispatched	Event Days Available	Event Hours Dispatched	Event Hours Available
PG&E	Day Ahead	28	30	60	180
SCE*	Day Ahead	24	30	63	180
	Day Of	29	30	80	180
SDG&E	Day Ahead	27	26	93	144
	Day Of	24	26	85	144

*Counts shown for summer months only (May through October)

- More event days called in PY2020 with IOUs calling close to the maximum number of event days per month.
- PG&E and SCE called mostly events with 1-hour or 2-hour durations.
- SDG&E called longer events with mostly 2-hour or 4-hour durations.

Statewide Ex-Post Impacts

Non-Residential

Utility	Program	Nominated Accounts	Dispatched Accounts	Dispatched Capacity (MW)	Load Impact (MW)	% Delivered
PG&E	Day Ahead	913	531	15.6	10.0	64%
SCE*	Day Ahead	415	387	6.0	3.9	65%
	Day Of	383	312	[redacted]	[redacted]	[redacted]
SDG&E	Day Ahead	19	23	0.6	0.4	71%
	Day Of	159	158	2.9	2.2	74%

*Results shown for summer months only (May through October)

- PG&E DA is the largest contributor with 10.0 MW
- None of the programs met/exceeded their dispatched capacity, on average.

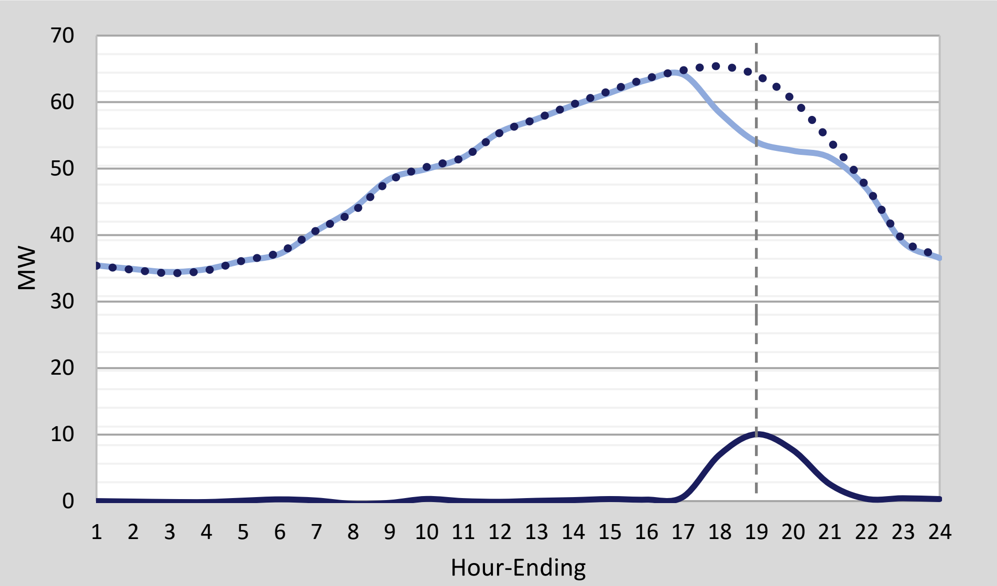
PG&E Ex-Post Impacts

Non-Residential

Day Ahead

Top Takeaways

- Average load impact of 10.0 MW (64% of dispatched)
- Highest in August (19.1 MW)
- Highest % delivered in June (103%)



Month	Nominated Accounts	Dispatched Accounts	Dispatched Capacity (MW)	Load Impact (MW)	% Delivered
May	817	-	-	-	-
June*	846	20	0.5	0.5	103%
July*	998	326	13.8	11.3	81%
August	1,029	833	24.6	19.1	78%
September	979	445	17.1	11.3	66%
October	807	512	9.4	7.9	83%
Average	**913**	**531**	**15.6**	**10.0**	**64%**

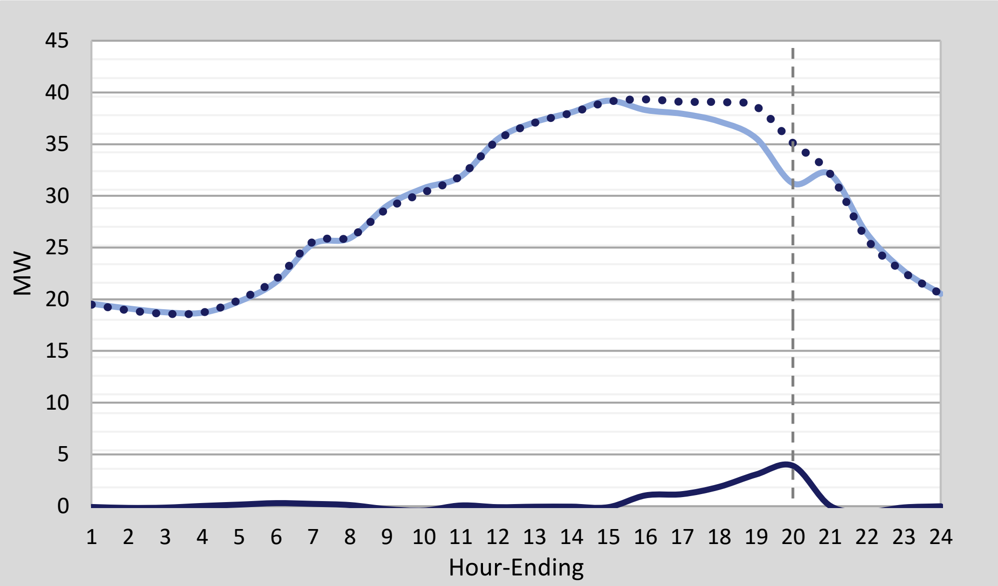
*Results for HE20 instead of HE19.

SCE Ex-Post Impacts

Day Ahead

Top Takeaways

- Average load impact of 3.9 MW (65% of dispatched)
- Dispatched mostly system-level events.
- Highest in Sept (7.0 MW)
- Highest % delivered in Sept (109%)



Month	Nominated Accounts	Dispatched Accounts	Dispatched Capacity (MW)	Load Impact (MW)	% Delivered
May	527	295	2.9	1.2	42%
June	351	336	5.4	5.2	97%
July	403	403	6.2	5.5	88%
August	382	382	6.4	5.1	80%
September*	413	413	6.5	7.0	109%
October*	412	412	5.9	3.7	64%
Average	**415**	**387**	**6.0**	**3.9**	**65%**

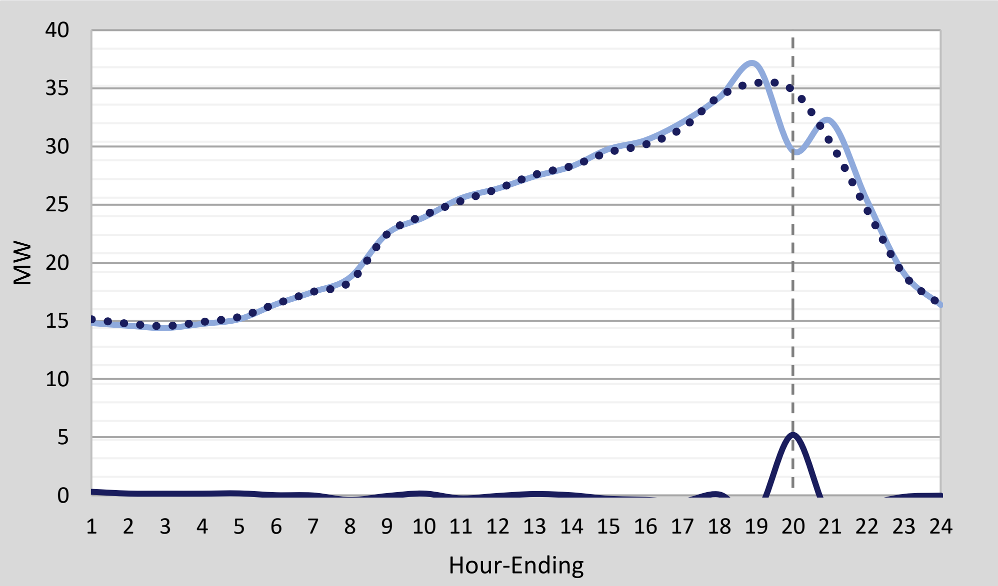
*Results for HE19 instead of HE20.

SCE Ex-Post Impacts

Day Of

Top Takeaways

- Mostly redacted due to 15% load rule (one large customer)
- Graph shown if for Aug. 3, 2021
  - Top performing August event day with 5.2 MW (93% delivered)



Month	Nominated Accounts	Dispatched Accounts	Dispatched Capacity (MW)	Load Impact (MW)	% Delivered
May	357	326	4.6	1.9	42%
June	467	440	[redacted]	[redacted]	[redacted]
July	428	218	[redacted]	[redacted]	[redacted]
August	444	370	4.9	3.3	66%
September*	307	307	[redacted]	[redacted]	[redacted]
October*	294	294	[redacted]	[redacted]	[redacted]
Average	**383**	**312**	[redacted]	[redacted]	[redacted]

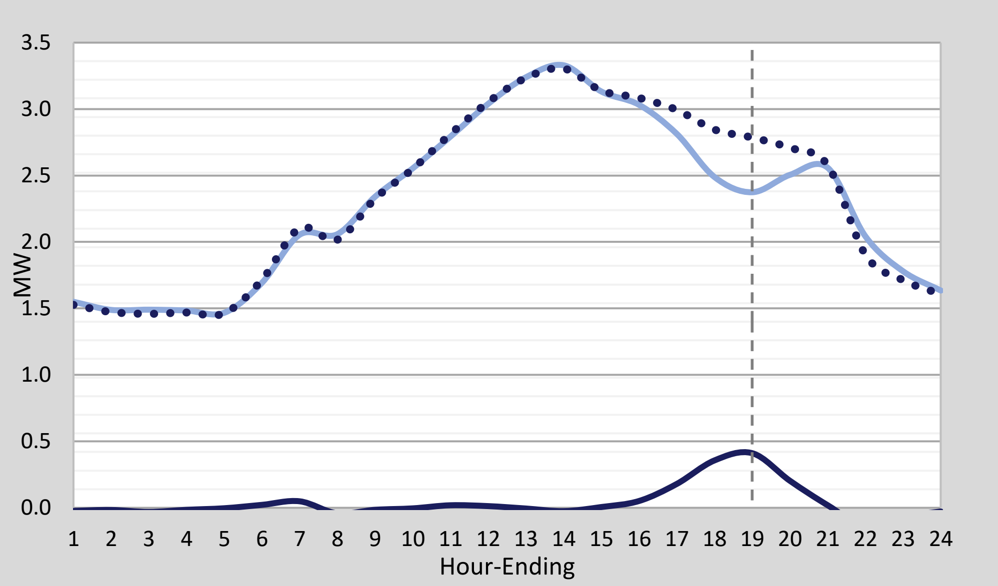
*Results for HE19 instead of HE20.

SDG&E Ex-Post Impacts

Day Ahead

Top Takeaways

- Average load impact of 0.41 MW (71% of dispatched)
- Dispatched mostly system-level events.
- Highest in August (0.6 MW)
- Highest % delivered in June (111%)



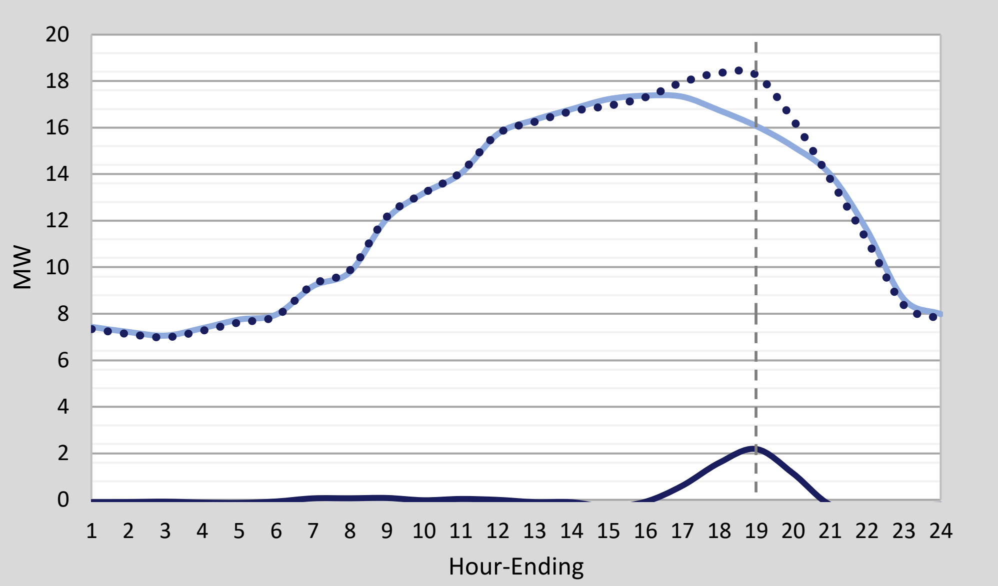
Month	Nominated Accounts	Dispatched Accounts	Dispatched Capacity (MW)	Load Impact (MW)	% Delivered
May	9	-	-	-	-
June	11	11	0.49	0.55	111%
July	24	24	0.62	0.39	62%
August	24	24	0.64	0.60	93%
September	24	24	0.69	0.32	46%
October	20	20	0.36	0.31	86%
Average	**19**	**23**	**0.58**	**0.41**	**71%**

SDG&E Ex-Post Impacts

Day Of

Top Takeaways

- Average load impact of 2.2 MW (74% of dispatched)
- Dispatched mostly system-level events.
- Highest in July (2.8 MW)
- Highest % delivered in June (115%)



Month	Nominated Accounts	Dispatched Accounts	Dispatched Capacity (MW)	Load Impact (MW)	% Delivered
May	178	-	-	-	-
June	142	101	2.4	2.7	115%
July	175	175	3.2	2.8	87%
August	175	175	3.2	2.3	71%
September	152	152	3.2	2.2	69%
October	129	129	2.2	1.5	65%
Average	**159**	**158**	**2.9**	**2.2**	**74%**

Statewide System Peak Hour

Aug 18, 2020

(HE16)

Utility	Program	Dispatched Accounts	Dispatched Capacity (MW)	Load Impact (MW)	Event Temp (°F)
PG&E	Day Ahead	-	-	-	-
SCE	Day Ahead	-	-	-	-
	Day Of	36	0.5	0.7	88
SDG&E	Day Ahead	4	0.2	<0.1	100
	Day Of	66	0.9	0.5	86

- PG&E DA and SCE DA did not call events during the statewide system peak hour.
- All other programs contributed approx. 1.2 MW during the statewide system peak hour.

Ex-Ante
Load Impacts

Ex-Ante Analysis Approach

Weather-adjust customer-specific load impacts → Generate average per-customer load impacts by subgroup → Create 11-year annual load forecast → Assess uncertainty and produce confidence intervals

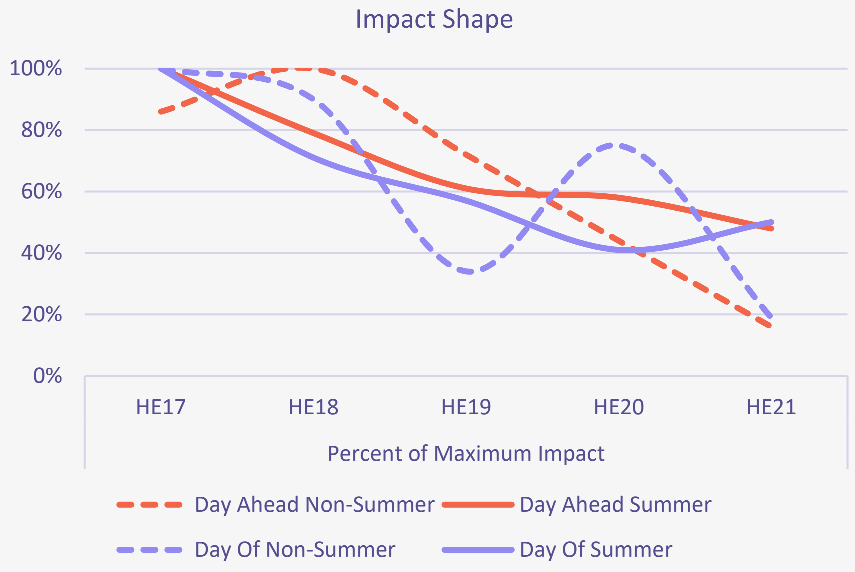
Key Assumptions in PY2020

- No COVID adjustments were made as the populations change significantly over time.
- Estimated load impacts for a 5-hour event during the RA window.
  - Started with the highest hourly impact from the ex-post analysis.
  - Incorporated a degradation shape using historical performance (PY2019 and PY2020), looking at average % impacts for different event durations.

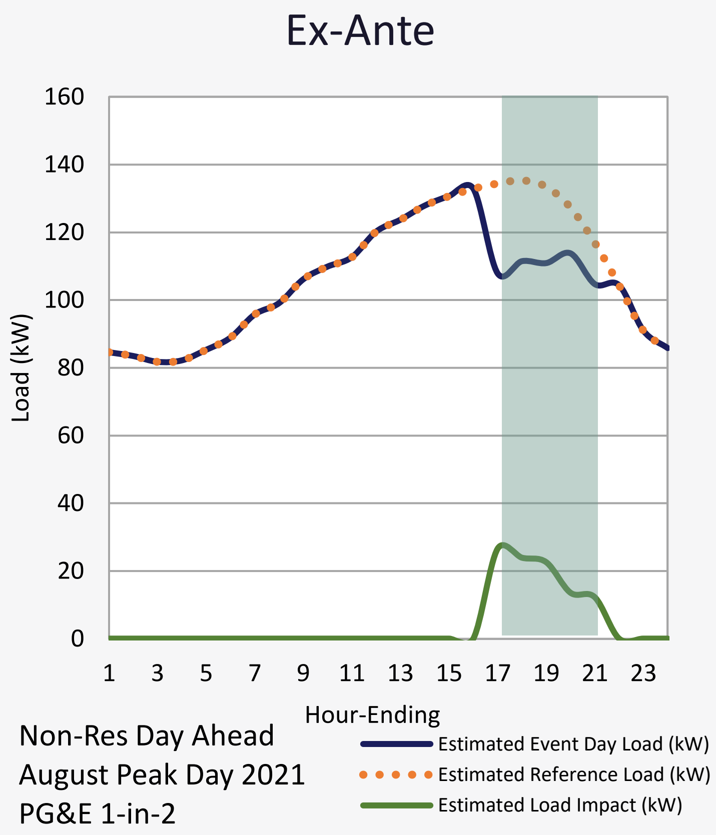
Impact Degradation Example (SCE)

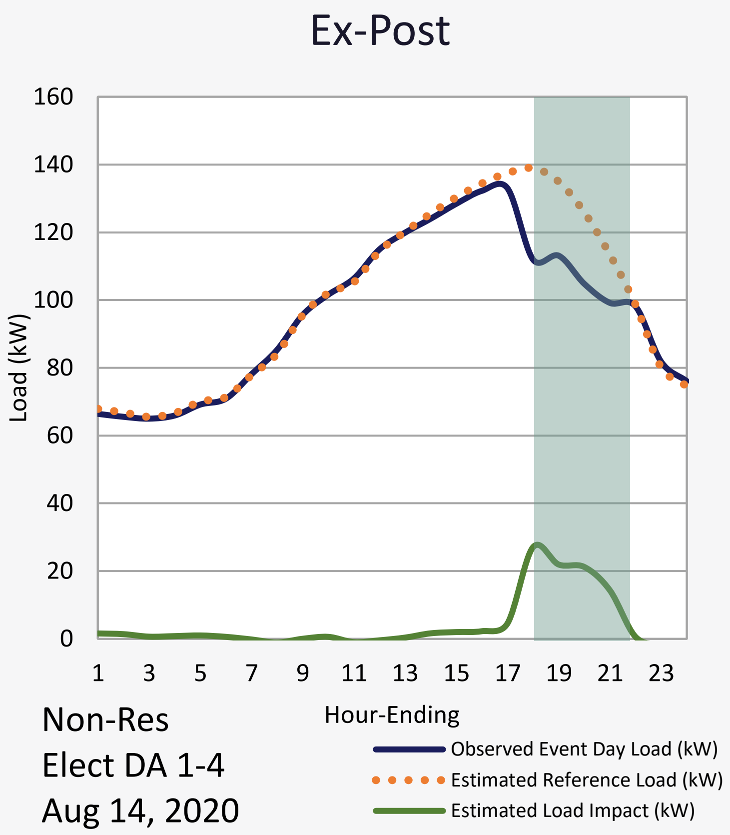
Program	Season	Percent of Maximum Impact				
		HE17	HE18	HE19	HE20	HE21
Day Ahead	Non-Summer	86%	100%	72%	44%	16%
	Summer	100%	79%	61%	58%	48%
Day Of	Non-Summer	100%	90%	34%	75%	19%
	Summer	100%	71%	57%	41%	50%

- Derived using % impacts from PY2019 and PY2020 events.
- Summer events had sufficient historical data from events ranging from 1-hour to 6-hour events.
- Non-summer events had only two long events (5-hour or 6-hour). Degradation in the 5th hour is from degradation of previous hours.

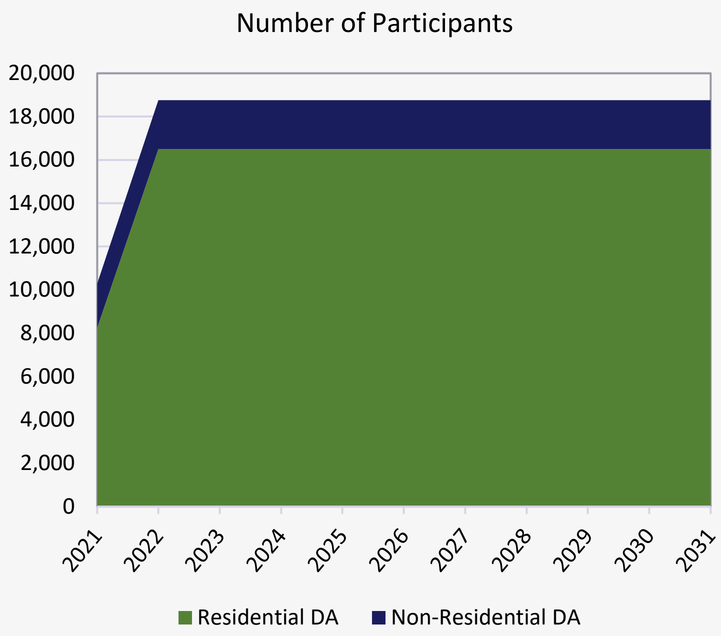


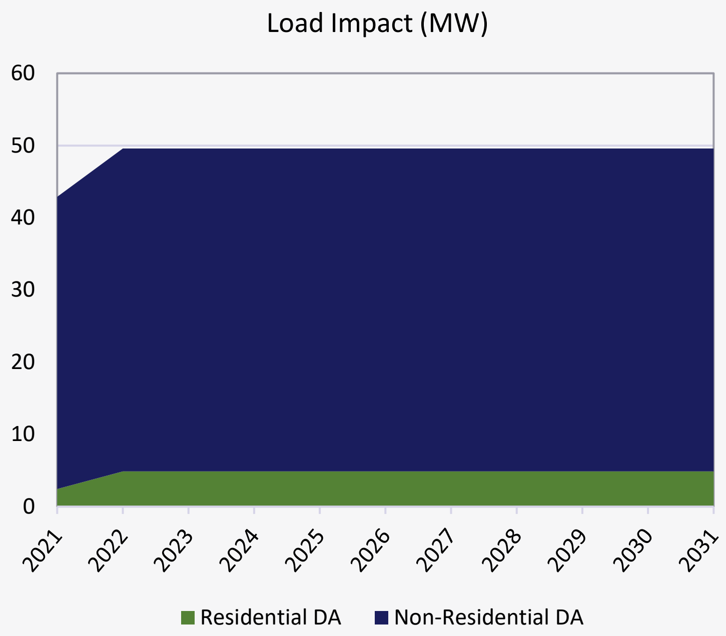
Impact Degradation Example (PG&E)





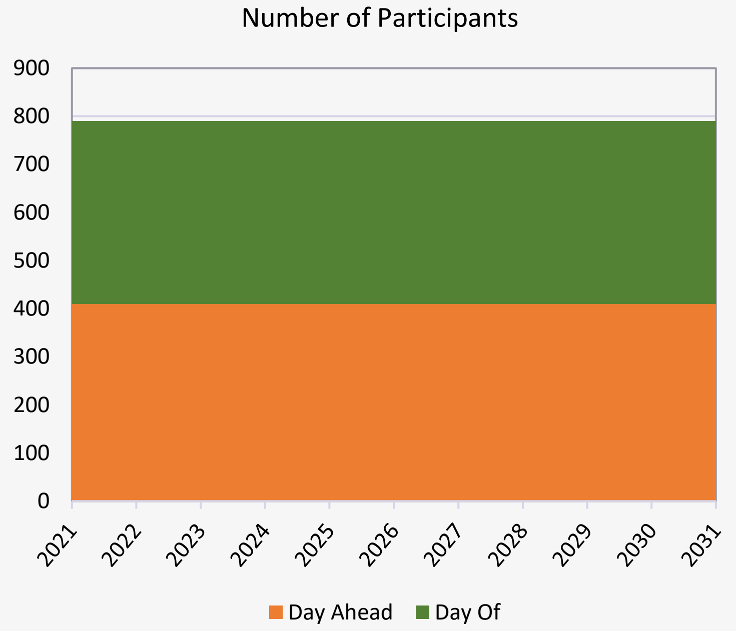
PG&E Ex-Ante Forecast





	Program	Nominated Accounts	Per-customer Load Impact (kW)	Aggregate Load Impact (MW)
PY2019 Forecast (2021 August Peak Day, 1-in-2 IOU)	Res DA	25,000	0.4	10.0
	Non-Res DA	1,586	24.0	38.0
	Total	**26,586**	**1.8**	**48.0**
PY2020 Forecast (2021 August Peak Day, 1-in-2 IOU)	Res DA	8,247	0.3	2.4
	Non-Res DA	2,049	19.8	40.5
	Total	**10,296**	**4.2**	**42.9**

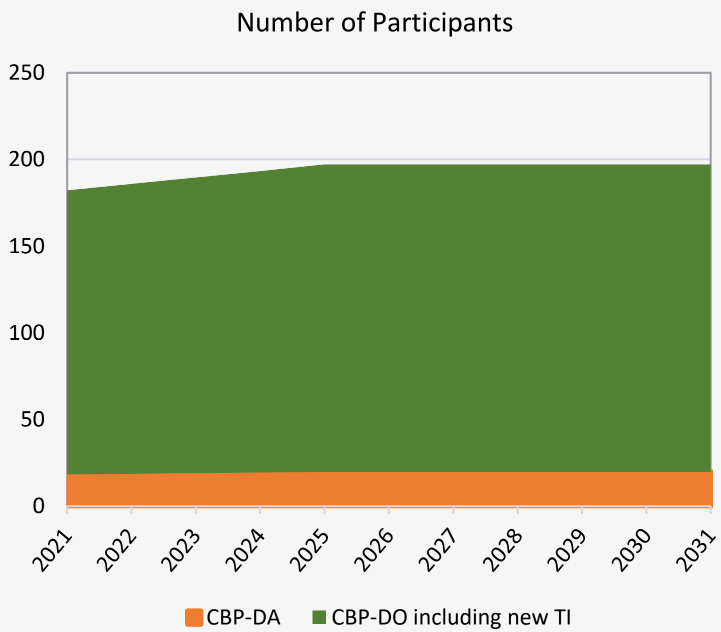
SCE Ex-Ante Forecast

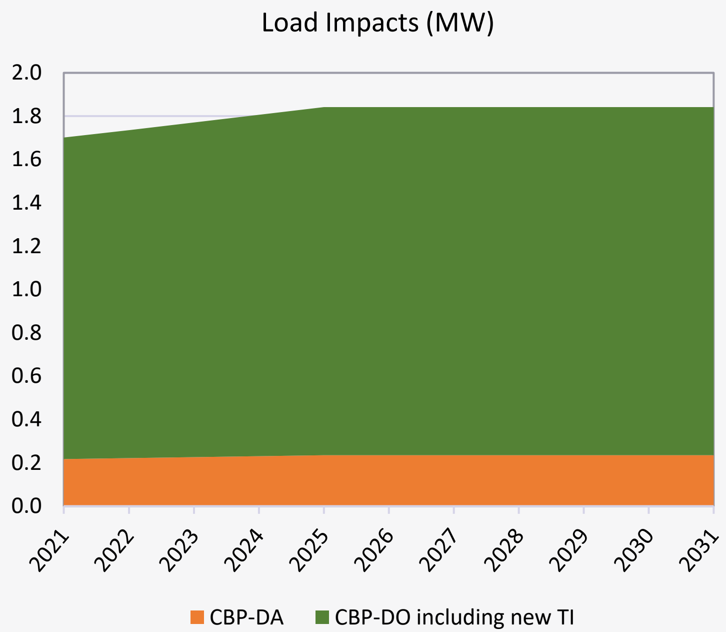


Confidential

	Program	Nominated Accounts	Per-customer Load Impact (kW)	Aggregate Load Impact (MW)
PY2019 Forecast (2021 August Peak Day, 1-in-2 IOU)	Day Ahead	384	[redacted]	[redacted]
	Day Of	233	[redacted]	[redacted]
	Total	**617**	[redacted]	[redacted]
PY2020 Forecast (2021 August Peak Day, 1-in-2 IOU)	Day Ahead	410	6.2	2.6
	Day Of	380	[redacted]	[redacted]
	Total	**790**	[redacted]	[redacted]

SDG&E Ex-Ante Forecast





	Program	Nominated Accounts	Per-customer Load Impact (kW)	Aggregate Load Impact (MW)
PY2019 Forecast (2021 August Peak Day, 1-in-2 IOU)	Day Ahead	11	18.7	0.2
	Day Of	193	17.0	3.3
	Total	**204**	**17.2**	**3.5**
PY2020 Forecast (2021 August Peak Day, 1-in-2 IOU)	Day Ahead	18	11.8	0.2
	Day Of	164	9.1	1.5
	Total	**182**	**9.3**	**1.7**

Statewide Ex-Ante Impacts

Utility	Program	PY 2021 Nominated Accounts	PY 2021 Nominated Capacity (MW)	PY 2031 Nominated Accounts	PY 2031 Nominated Capacity (MW)
PG&E	Day Ahead	10,296	42.9	18,752	49.6
SCE*	Day Ahead	410	2.6	410	2.6
	Day Of	380	[redacted]	380	[redacted]
SDG&E	Day Ahead	18	0.2	20	0.2
	Day Of	164	1.5	177	1.6

*Counts shown for summer months only (May through October)

Key Findings

Key Findings

Program Success

- None of the programs met/exceeded capacity nominations, on average.
- All programs showed success on certain months or events (90+% delivery).
- SDG&E's 1-9 PM dispatch window was successful with 110% (DA) and 99% (DO) deliveries.

Participant Recruitment

- Recruitment/participation adjusts to fill aggregator nominations.
- Some/all of participant population changes from year-to-year.
  - COVID adjustment was not necessary.

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Thank You.

AEG
APPLIED ENERGY GROUP

SOUTHERN CALIFORNIA EDISON SMART ENERGY PROGRAM: 2020 LOAD IMPACT EVALUATION

APRIL 29, 2021

Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

SEP PROGRAM DESCRIPTION

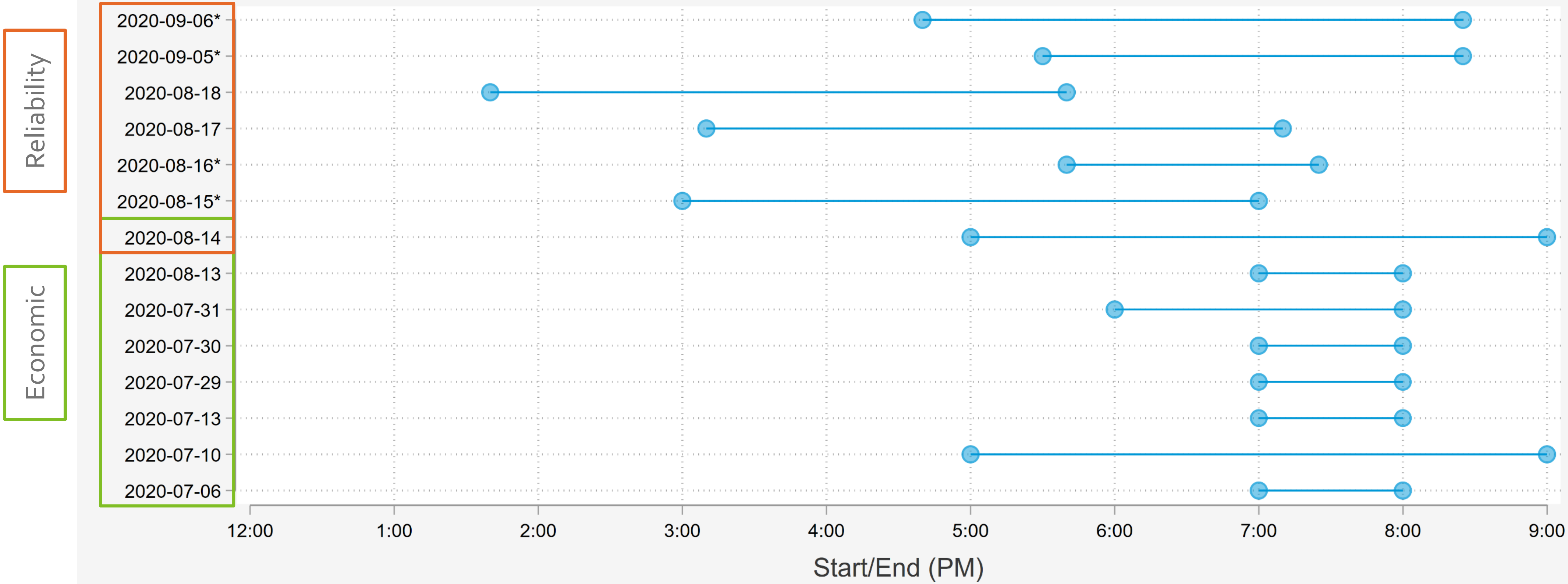
Overview

- SEP operates through temporary thermostat adjustments which reduce AC usage and lowers electric demand.
- Events can be called year-round, though customers only receive bill credits for June through September participation.
- One-time $75 bill credit for enrolling and a daily bill credit of $0.3275 per day June to September.
- No more than 180 hours of SEP events can be called in a calendar year.
- SEP includes multiple vendors and smart thermostat manufacturers (OEMs)

Participant Make-Up

Segmentation Variable	Segment Description	Participants
All	All Customers	50,809
LCA	Big Creek/Ventura	6,040
	LA Basin	43,403
	Outside	1,366
Low Income	CARE	7,337
	Non-CARE	43,472
NEM	NEM Customer	11,217
	Non-NEM Customer	39,592
Size	Above Mean kW	25,218
	Below Mean kW	25,591
Sublap	SCEC	20,538
	SCEN	5,137
	SCEW	22,867
	SCHD	1,318
	SCLD	48
	SCNW	901
Tariff	Dynamic	14,080
	Flat	36,729
Zone	Remainder of System	21,789
	South Orange County	10,615
	South of Lugo	18,405

2020 EVENTS VARIED IN TIMING AND DURATION; SEVERAL EVENTS STARTED/ENDED MID-HOUR



* Weekend event. Size of bubbles represents number of participants dispatched.

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SEP EX POST METHODOLOGY

Proxy Day Selection

- Three proxy days were selected for each event day based on SCE system load

Matched Controls

- A single control customer was chosen for each participant based on individual load during all proxy days
- Hard matched within NEM status, climate zone, and CDD bin groups
- Propensity score matching model with replacement

Regression Analysis

- Difference-in-differences panel regression
- Hourly event impacts estimated by subcategory and across all customers
- Separate regression for each event day hour using event day and it's 3 proxy days

2020 outages and COVID create special challenges for the evaluation. However, ex post is largely unaffected.

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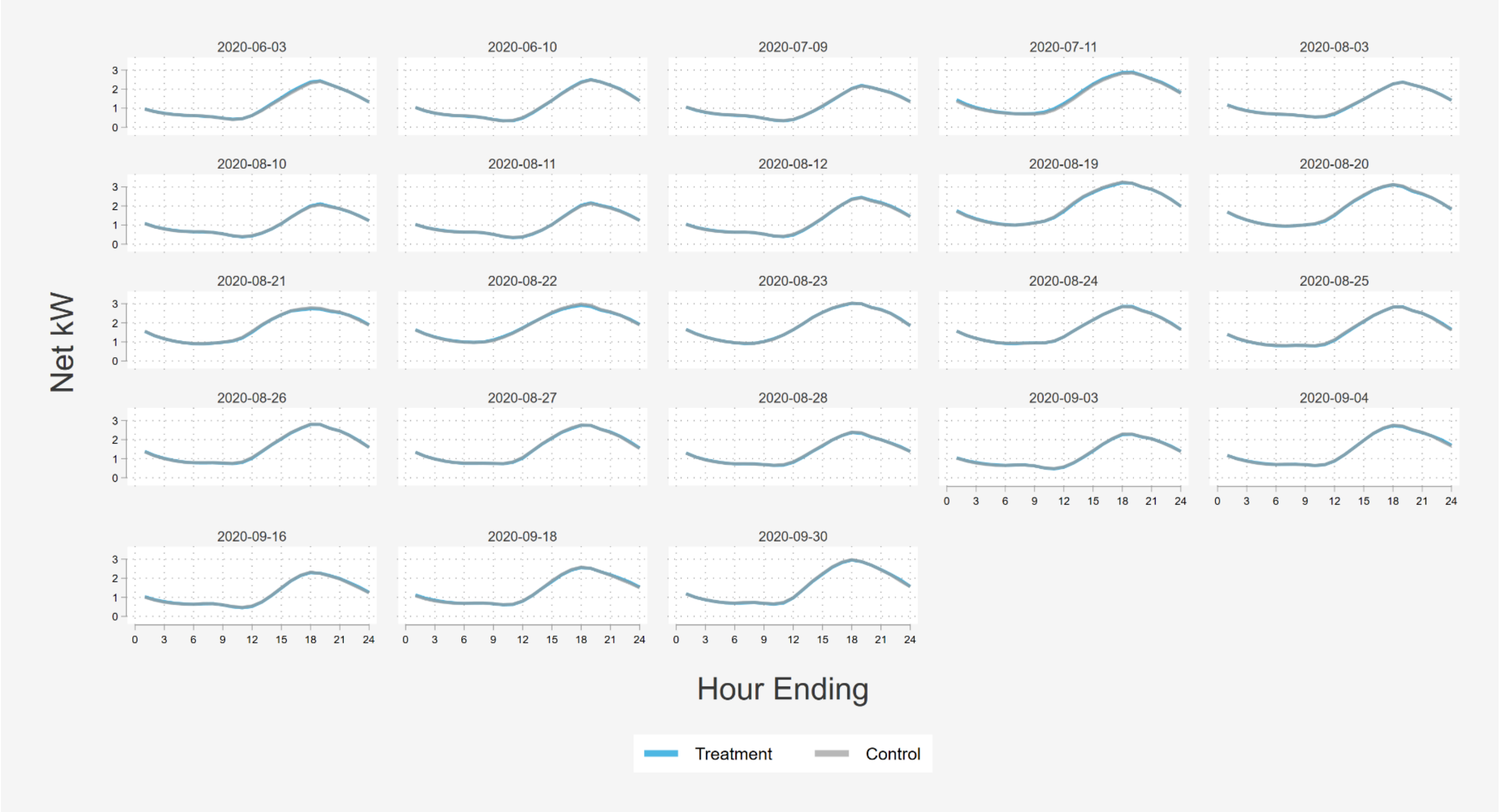
TREATMENT AND MATCHED CONTROL GROUP

- Control matches were assigned characteristics (including sub-LAPs and vendor) from their treated counterpart
- Weekend events get weekend proxies
  - 9/5 and 9/6 were unusually hot weekend events with no comparable weekend days
  - Regression analysis is used to close the gap between imperfectly matched proxy days

Average Hourly kW on Proxy Days



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SYSTEM PEAK DAY – 8/18/2020

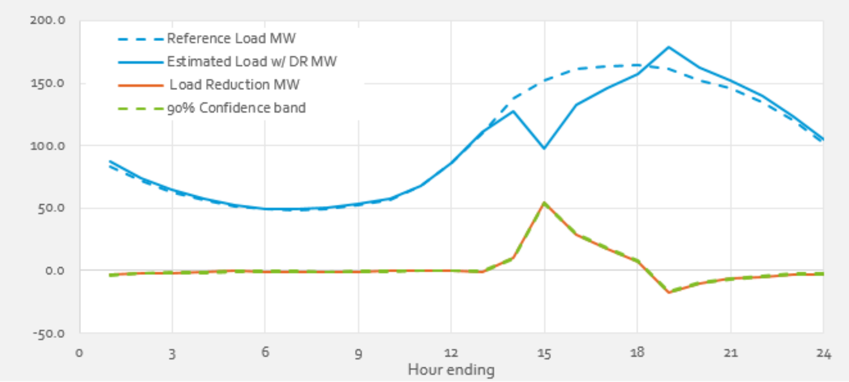
- Four-hour event
  - Two partial event hours
  - Three full event hours
- Maximum temp of 101.6°F

Table 1: Menu options

Program	SEP
Type of Result	Aggregate
Category	All
Subcategory	All Customers
Date	8/18/2020 (1:40pm-5:40pm)

Table 2: Event day information

Event Hours	1:40pm-5:40pm
Total sites	50,977
Daily maximum temperature	101.6
Full event hours load reduction (MW)	33.52
Full event hours % load reduction	21.5%
All event hours load reduction (MW)	23.54
All event hours % load reduction	21.5%



Hour Ending	Reference Load MW	Estimated Load w/ DR MW	Load Reduction MW	% Load Reduction	Avg Temp, site weighted F
1	83.52	86.84	-3.32	-4%	78.5
2	71.43	73.71	-2.27	-3%	77.7
3	62.70	64.54	-1.84	-3%	76.9
4	55.94	57.48	-1.54	-3%	76.1
5	51.71	52.24	-0.53	-1%	75.5
6	48.93	49.65	-0.72	-1%	75.2
7	48.61	49.43	-0.82	-2%	75.1
8	49.61	50.64	-1.03	-2%	75.1
9	52.66	53.35	-0.69	-1%	76.9
10	56.90	57.50	-0.59	-1%	81.2
11	67.73	67.67	0.06	0%	86.5
12	86.44	86.50	-0.06	0%	91.0
13	110.44	111.46	-1.03	-1%	94.9
14	137.55	127.71	9.83	7%	99.1
15	151.74	97.73	54.01	36%	100.5
16	161.55	132.53	29.02	18%	101.6
17	163.17	145.63	17.54	11%	98.0
18	164.53	157.24	7.29	4%	94.2
19	161.62	179.14	-17.52	-11%	91.5
20	152.30	162.32	-10.03	-7%	88.7
21	145.86	152.48	-6.63	-5%	85.6
22	135.04	140.21	-5.17	-4%	83.4
23	119.84	122.99	-3.15	-3%	81.8
24	101.72	104.78	-3.06	-3%	80.6
Daily	**Reference Load MWh**	**Estimated Load w/ DR MWh**	**Energy Savings MWh Δ**	**% Change**	**Avg Temp, site weighted F**
	2,441.52	2,383.78	57.75	2%	85.2

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DATA DRIVEN RESEARCH AND INSIGHTS

EX POST RESULTS

- On 7/13, 7/29, 8/15, and 8/16, only a subset of sub-LAPs were called
- Events marked with an asterisk (*) include partial event hours which are not shown here

Event Date	Dispatch Region	Start Time	End Time	Participants	Average Event Temp	Daily Max Temp	Per Home kW Reduction				Average Full Hour Impact (kW Reduction)	Average Aggregate Full Hour Impact (MW Reduction)
							Hour 1	Hour 2	Hour 3	Hour 4		
7/6/2020 (7pm-8pm)	Territory Wide	7:00 PM	8:00 PM	51,842	86.0	89.9	0.76				0.76	39.1
7/10/2020 (5pm-9pm)	Territory Wide	5:00 PM	9:00 PM	51,776	88.4	92.6	0.82	0.40	0.27	0.18	0.42	21.8
7/13/2020 (7pm-8pm)	SCEC, SCHD, SCLD, SCNW, SCEW	7:00 PM	8:00 PM	46,529	81.5	87.2	0.67				0.67	31.4
7/29/2020 (7pm-8pm)	SCEC, SCHD, SCLD, SCNW, SCEW	7:00 PM	8:00 PM	46,178	82.2	86.9	0.55				0.55	25.6
7/30/2020 (7pm-8pm)	Territory Wide	7:00 PM	8:00 PM	51,383	89.7	92.0	0.72				0.72	36.9
7/31/2020 (6pm-8pm)	Territory Wide	6:00 PM	8:00 PM	51,371	92.2	95.6	0.84	0.45			0.64	33.1
8/13/2020 (7pm-8pm)	Territory Wide	7:00 PM	8:00 PM	51,079	90.2	94.4	0.78				0.78	39.7
8/14/2020 (5pm-9pm)	Territory Wide	5:00 PM	9:00 PM	51,071	94.6	98.6	0.99	0.47	0.30	0.23	0.50	25.4
8/15/2020 (3pm-7pm)	SCEC, SCEN, SCEW, SCHD, SCNW	3:00 PM	7:00 PM	50,939	96.8	97.9	0.91	0.63	0.33	0.26	0.53	27.2
*8/16/2020 (5:40pm-7:25pm)	SCEC, SCEN, SCEW, SCHD, SCNW	5:40 PM	7:25 PM	50,939	88.2	95.6	0.80				0.80	40.7
*8/17/2020 (3:10pm-7:10pm)	Territory Wide	3:10 PM	7:10 PM	51,002	94.7	95.7	0.76	0.40	0.27		0.48	24.3
*8/18/2020 (1:40pm-5:40pm)	Territory Wide	1:40 PM	5:40 PM	50,977	100.0	101.6	1.06	0.57	0.34		0.66	33.5
*9/5/2020 (5:30pm-8:25pm)	Territory Wide	5:30 PM	8:25 PM	50,809	104.7	107.8	1.00	0.55			0.77	39.3
*9/6/2020 (4:40pm-8:25pm)	Territory Wide	4:40 PM	8:25 PM	50,809	102.9	108.6	1.07	0.60	0.42		0.70	35.5
Average Event Day (7pm-8pm)	Territory Wide	7:00 PM	8:00 PM	51,437	88.6	92.0	0.75				0.75	38.6
Average Event Day (5pm-9pm)	Territory Wide	5:00 PM	9:00 PM	51,426	91.5	95.6	0.91	0.44	0.29	0.21	0.46	23.6

Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

SYSTEM OUTAGE DAYS – 8/14 & 8/15

Table 1: Menu options

Program	SEP
Type of Result	Aggregate
Category	All
Subcategory	All Customers
Date	8/14/2020 (5pm-9pm)

Table 2: Event day information

Event Hours	5pm-9pm
Total sites	51,071
Daily maximum temperature	98.6
Full event hours load reduction (MW)	25.40
Full event hours % load reduction	16.3%
All event hours load reduction (MW)	25.40
All event hours % load reduction	16.3%

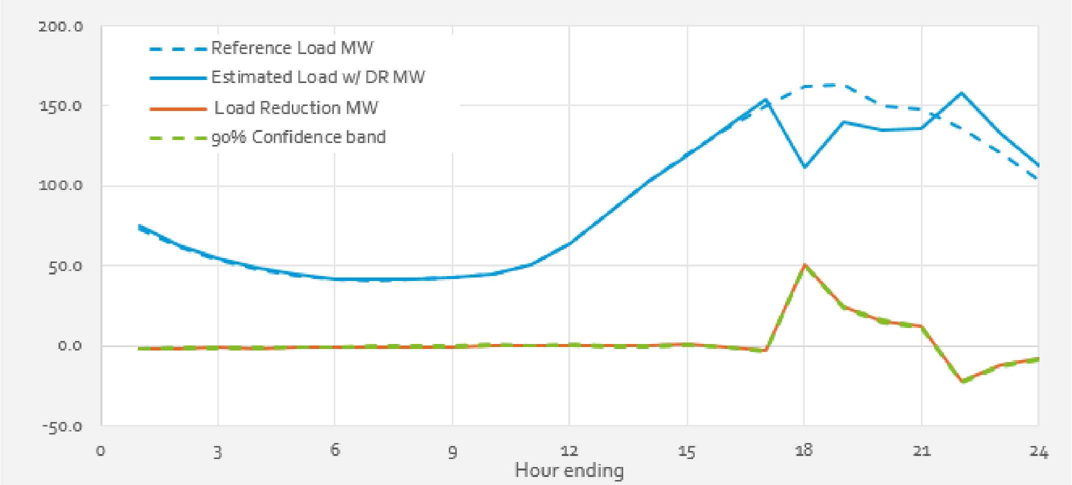
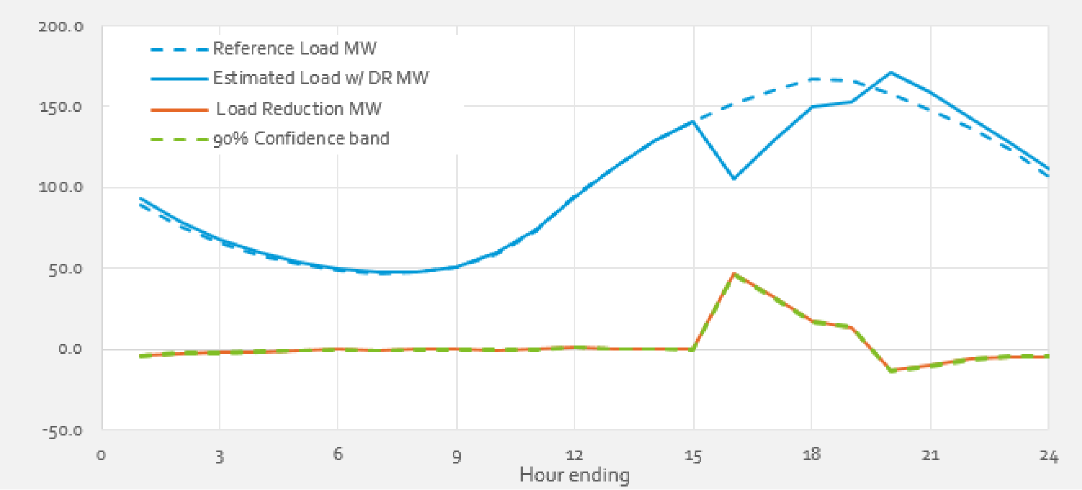


Table 1: Menu options

Program	SEP
Type of Result	Aggregate
Category	All
Subcategory	All Customers
Date	8/15/2020 (3pm-7pm)

Table 2: Event day information

Event Hours	3pm-7pm
Total sites	50,939
Daily maximum temperature	97.9
Full event hours load reduction (MW)	27.23
Full event hours % load reduction	16.9%
All event hours load reduction (MW)	27.23
All event hours % load reduction	16.9%



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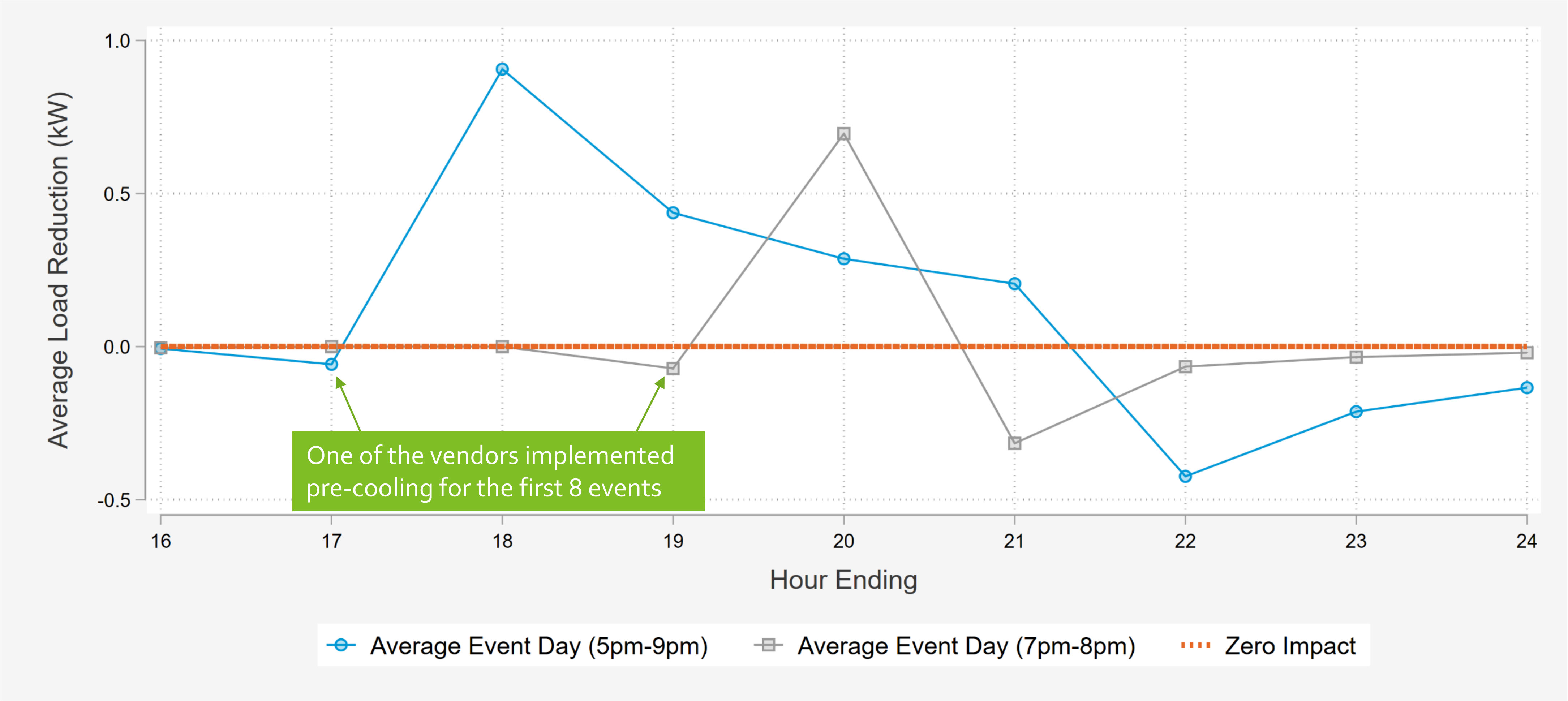
DATA DRIVEN RESEARCH AND INSIGHTS

EVENT IMPACTS ARE LARGEST DURING THE FIRST HOUR OF DISPATCH AND FADE IN SUBSEQUENT HOURS



EX POST COMPARISON TO PRIOR YEARS – AVERAGE EVENT DAYS

Measure	2017 (2-6PM)	2018 (2-6PM)	2019 (5-9PM)	2020 (5-9PM)
Avg. Reference Load (kW)	2.31	1.50	2.50	2.74
Avg. Load Impact (kW)	0.64	0.42	0.53	0.46
% Load Impact	27.8%	27.9%	21.1%	16.7%
Avg. Event Temperature	89.8	75.7	84.9	91.5
Heat Buildup (Avg. °F, Midnight to 5 PM)	81.4	75.4	80.6	79.9
Participants	34,120	51,089	52,239	51,426

- 2019 shift to later event window raises the reference load & reduces percent impacts
  - Significant CCA attrition between 2018 & 2019
- Enrolled vs available for dispatch

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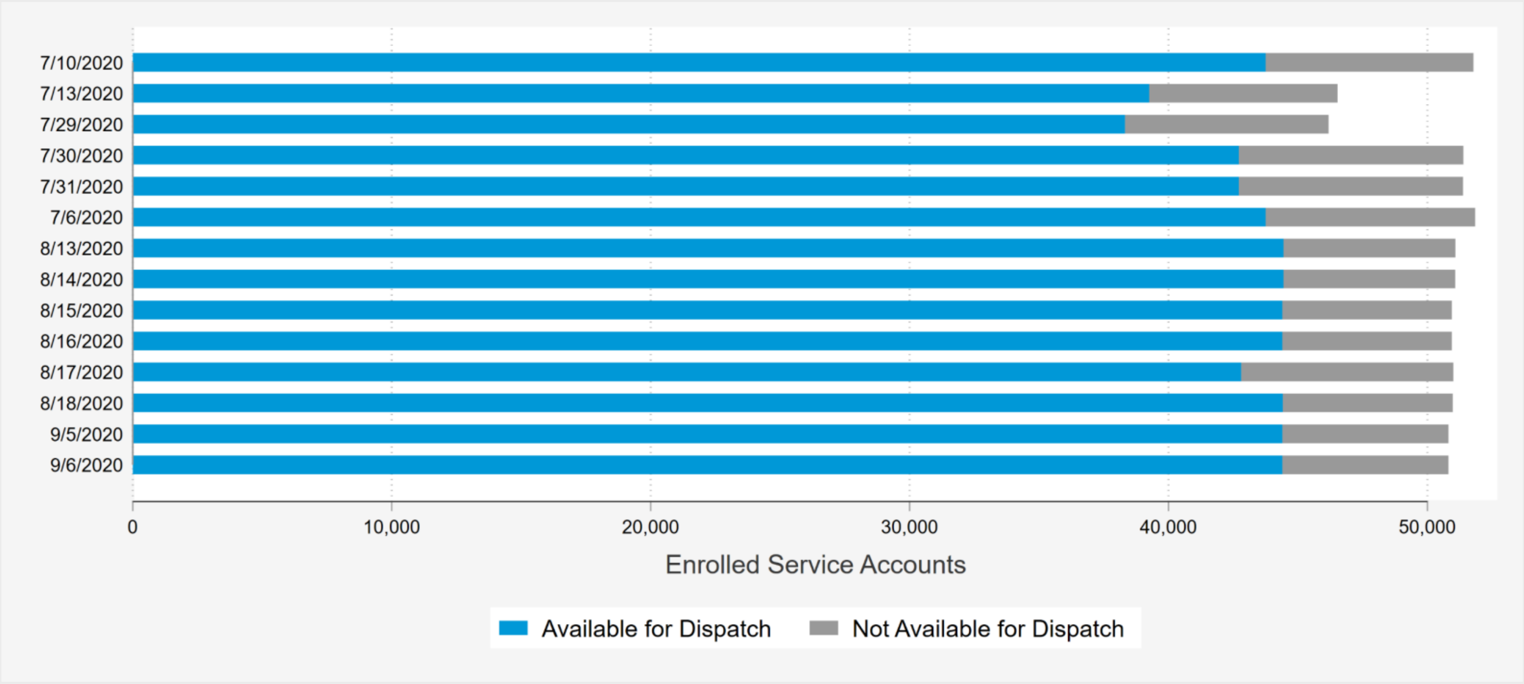
DATA DRIVEN RESEARCH AND INSIGHTS

AVAILABLE FOR DISPATCH



- Contractual issues in 2020 resulted in some enrolled thermostats not available to vendor for dispatch
- SCE & DSA don't have visibility into which accounts were available
  - Ex post impacts reflect all enrolled accounts
  - For ex ante impacts, we use an ITT adjustment to estimate an average "per-available" impact

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DATA DRIVEN RESEARCH AND INSIGHTS

AVERAGE 5-9PM EVENT DAY COMPARISON 2019 VS 2020

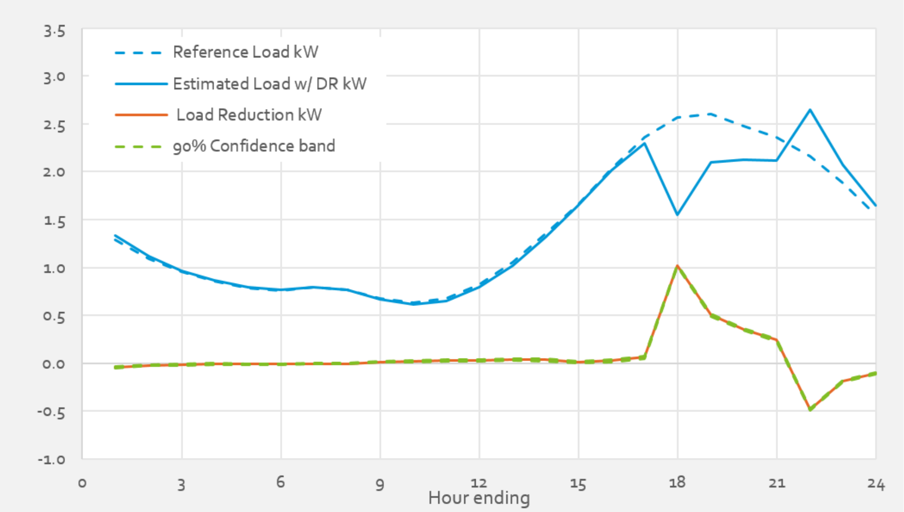
2019

Table 1: Menu options

Program	SEP
Type of Result	Average Customer
Category	All
Subcategory	All Customers
Date	Average Event Day (5pm-9pm)

Table 2: Event day information

Event Hours	5pm-9pm
Sites Dispatched	52,239
Daily Max Temp	93.4
Average Impact - kW	0.53
Average Impact - %	21.1%



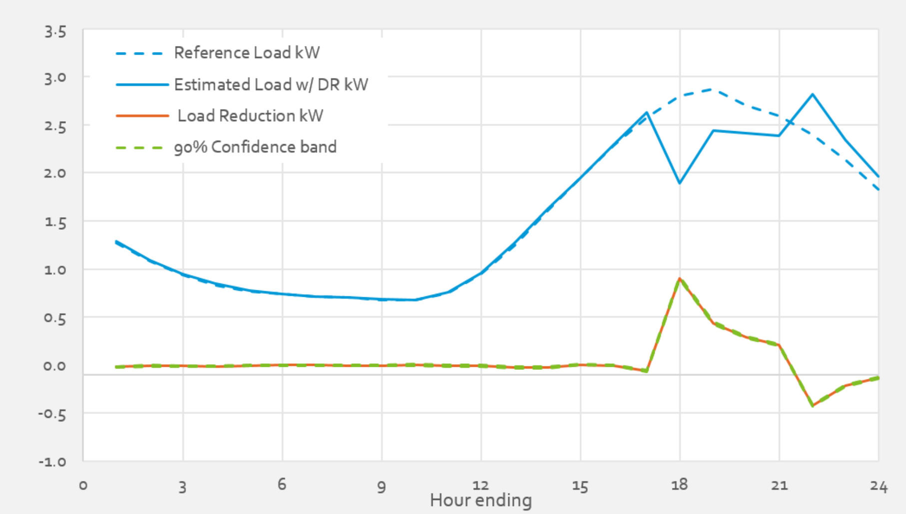
2020

Table 1: Menu options

Program	SEP
Type of Result	Average Customer
Category	All
Subcategory	All Customers
Date	Average Event Day (5pm-9pm)

Table 2: Event day information

Event Hours	5pm-9pm
Sites Dispatched	51,426
Daily Max Temp	95.6
Average Impact - kW	0.46
Average Impact - %	16.7%



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DATA DRIVEN RESEARCH AND INSIGHTS

2020 EX-POST VS 2019 EX-ANTE, HOW DID WE DO?

7/10/2020 (5-9 PM)			Per-Customer Impact (kW)			
Results	Daily Max Temp (F)	Customers	Hour 1	Hour 2	Hour 3	Hour 4
SCE 1-in-2 July Peak Day (2019 Ex-Ante Predictions for 2020)	93.0	59,649	0.85	0.53	0.38	0.28
Ex-Post	92.6	51,776	0.83	0.40	0.27	0.18
Ex-Post Available for Dispatch Adjustment	92.6	43,754	0.98	0.48	0.32	0.21

8/14/2020 (5-9 PM)			Per-Customer Impact (kW)			
Results	Daily Max Temp (F)	Customers	Hour 1	Hour 2	Hour 3	Hour 4
SCE 1-in-10 August Peak Day (2019 Ex-Ante Predictions for 2020)	97.2	60,249	0.93	0.56	0.40	0.30
Ex-Post	98.6	51,071	0.99	0.47	0.30	0.23
Ex-Post Available for Dispatch Adjustment	98.6	44,444	1.14	0.54	0.34	0.27

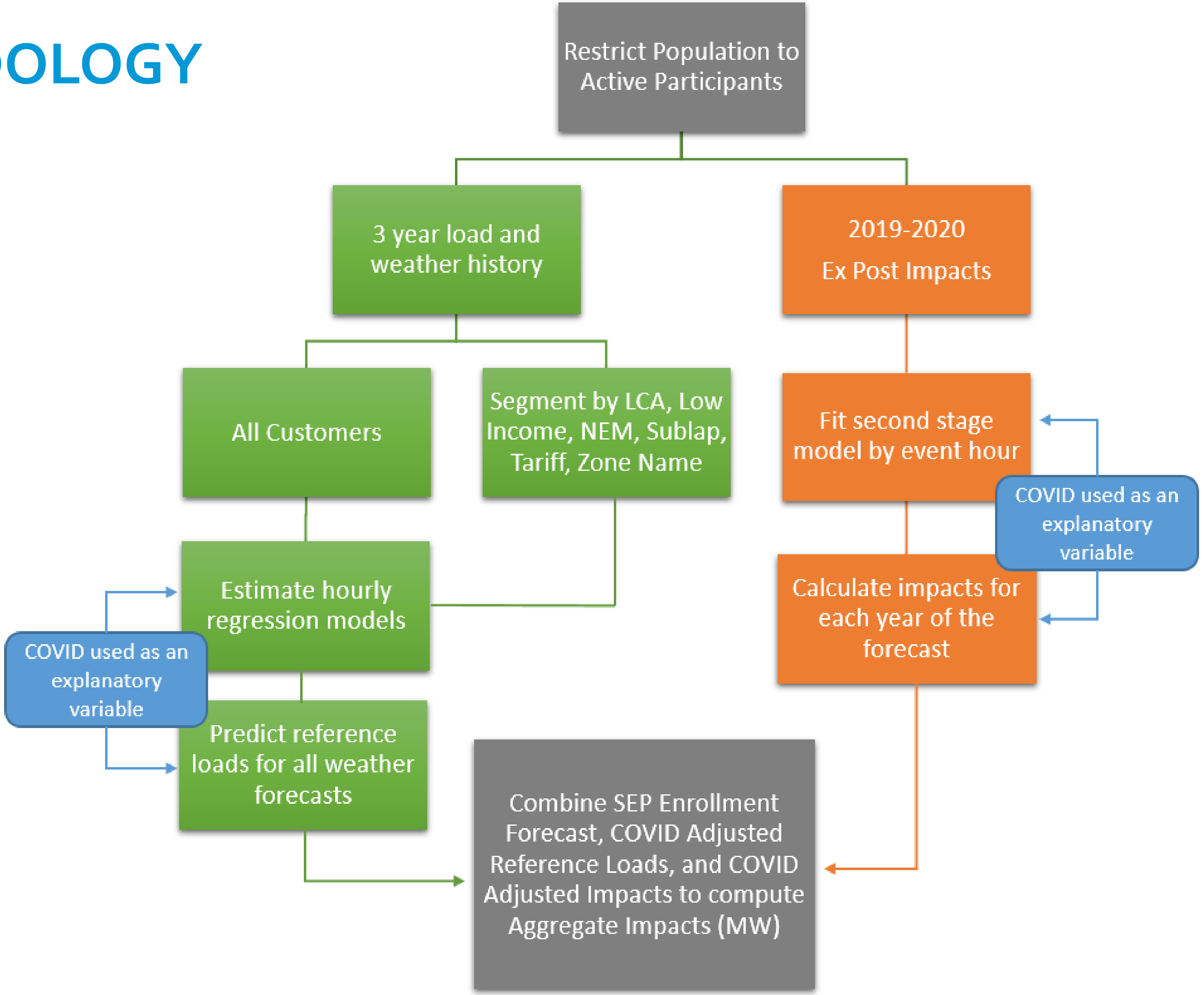
9/6/2020 (4:40-8:25 PM)			Per-Customer Impact (kW)			
Results	Daily Max Temp (F)	Customers	*Hour 1	*Hour 2	*Hour 3	*Hour 4
SCE 1-in-10 September Peak Day (2019 Ex-Ante Predictions for 2020)	99.7	61,726	0.86	0.54	0.40	0.30
Ex-Post	108.6	50,809	1.07	0.6	0.42	
Ex-Post Available for Dispatch Adjustment	108.6	44,400	1.22	0.69	0.48	

- These comparisons use the first four hours of the 2019 ex ante predictions
- July 10 was comparable to an SCE 1-in-2 day
- August 14 was an outage day
- September 6 was a weekend and ex post tables miss the first 20 minutes of DR impact (when impacts are largest)

Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

SEP EX ANTE METHODOLOGY

- Re-estimate ex post
  - Removed accounts with outages
  - Applied available for dispatch adjustment
  - Limited to customers still enrolled at end summer
- During 2020, COVID altered
  - Consumption trends (reference loads)
  - Enrollment strategies (enrollment forecasts)
  - Program effectiveness (ex post impacts)
- We incorporate COVID in the methodology, but the use of a control group is crucial to handle this type of disruption



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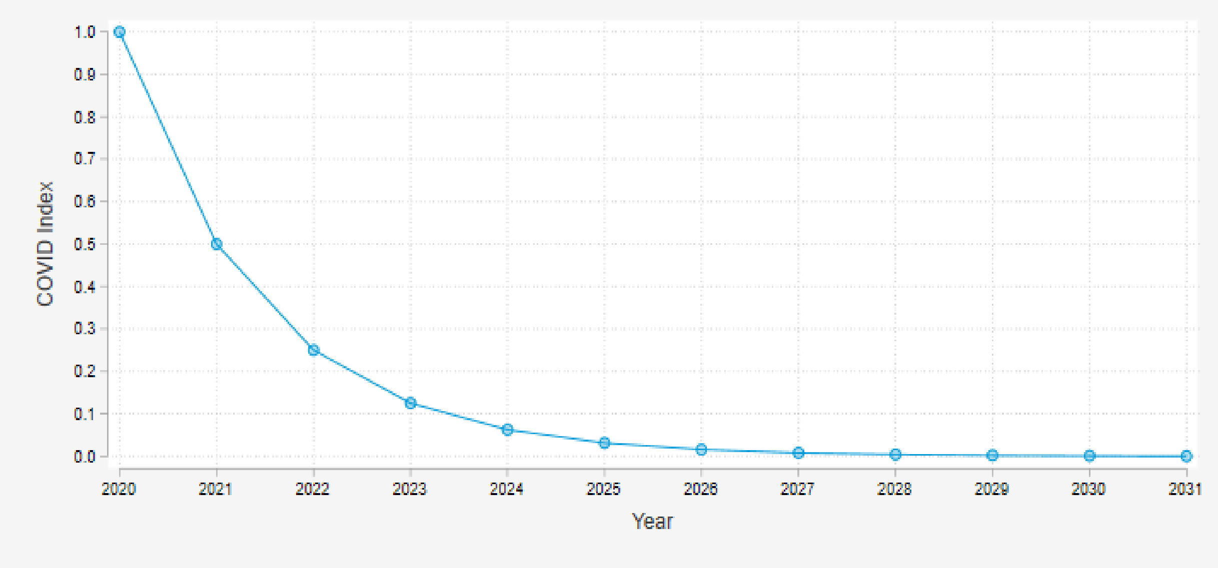
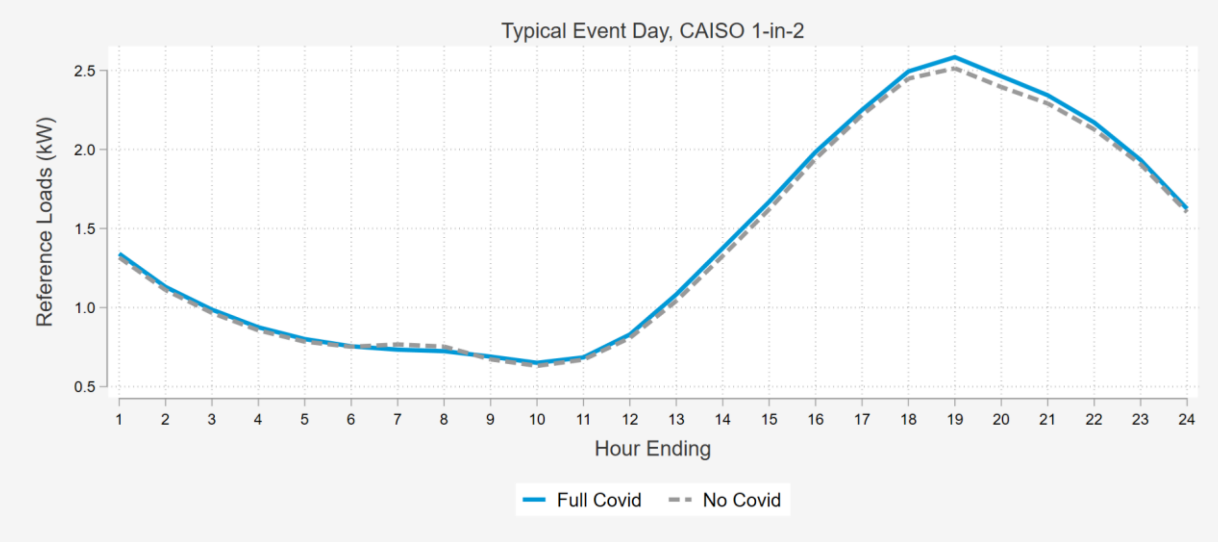
DATA DRIVEN RESEARCH AND INSIGHTS

COVID GLIDE PATH AND REFERENCE LOADS

- Typically, per-customer reference loads are consistent for all forecasted years.
- The Glide Path shows the assumed lingering impact of COVID effects in the forecast years
- COVID modifies the shape of the reference load and makes reference loads slightly higher during peak hours
- Reference loads are estimated using the same customers and weather conditions
- The COVID index weights the COVID and No-COVID reference loads for 2021-2031





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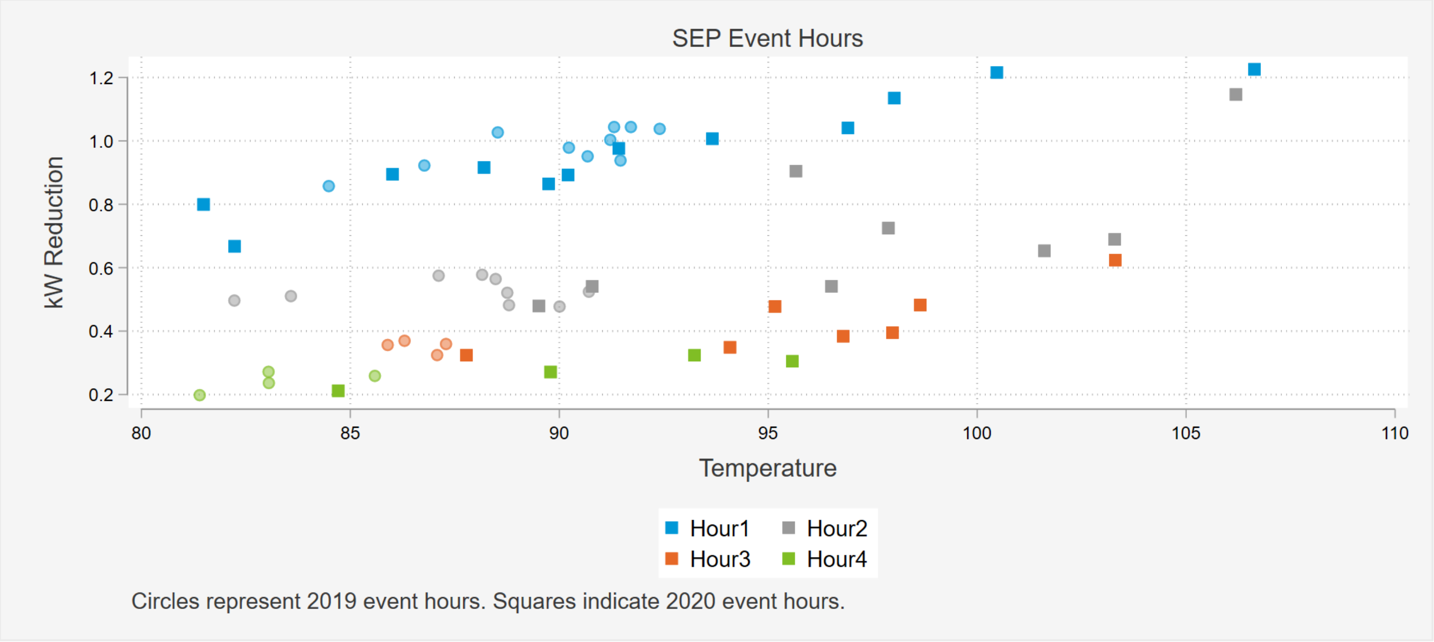
DATA DRIVEN RESEARCH AND INSIGHTS

RELATIONSHIP BETWEEN LOAD IMPACTS, TEMPERATURE, AND EVENT HOUR



- As in 2019:
  - Models are run separately for each event hour and snapback hour
- New in 2020:
  - 2019 and 2020 impacts are used
  - Models are run separately for each customer category
  - Second stage model regresses kw impact on temperature (°F) and COVID indicator
    - Temperature increases magnitude of impact
    - COVID decreases magnitude of impact

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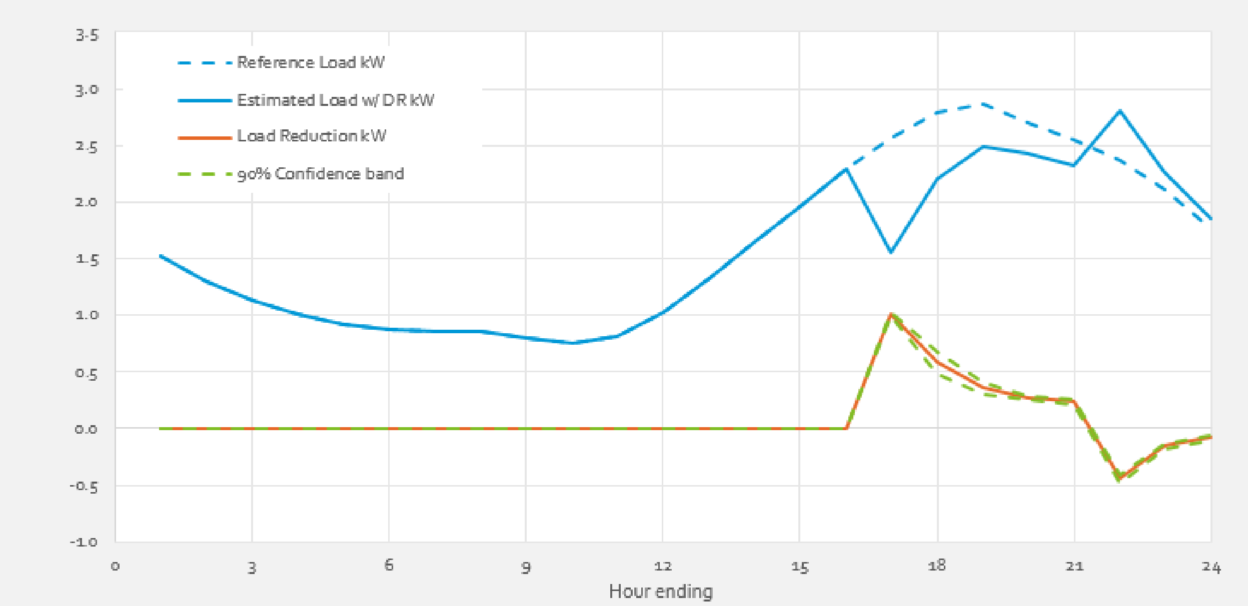
2021 AVERAGE CUSTOMER SCE 1-IN-2 CONDITIONS

Table 1: Menu options

Program	SEP
Type of Result	Average Customer
Category	All
Subcategory	All Customers
Weather Year	SCE 1-in-2
Day Type	Monthly System Peak Day
Month	August
Forecast Year	2021

Table 2: Event day information

Event Hours	4pm-9pm (RA Hours 4pm-9pm)
Sites Dispatched	59,498
Daily Max Temp (F)	93.3
Average Impact (kW)	0.49
% Load Reduction (Event window)	18.4%
Covid Index	0.50



Hour Ending	Reference Load kW	Estimated Load w/ DR kW	Load Reduction kW	% Load Reduction	Avg Temp, site weighted F
1	1.53	1.53	0.00	0.0%	78.1
2	1.29	1.29	0.00	0.0%	77.0
3	1.14	1.14	0.00	0.0%	76.2
4	1.01	1.01	0.00	0.0%	75.3
5	0.92	0.92	0.00	0.0%	74.6
6	0.88	0.88	0.00	0.0%	74.1
7	0.86	0.86	0.00	0.0%	73.5
8	0.86	0.86	0.00	0.0%	73.5
9	0.79	0.79	0.00	0.0%	75.6
10	0.75	0.75	0.00	0.0%	79.6
11	0.81	0.81	0.00	0.0%	83.7
12	1.02	1.02	0.00	0.0%	87.3
13	1.32	1.32	0.00	0.0%	89.7
14	1.65	1.65	0.00	0.0%	91.8
15	1.96	1.96	0.00	0.0%	93.3
16	2.29	2.29	0.00	0.0%	93.3
17	2.56	1.55	1.01	39.6%	92.8
18	2.80	2.21	0.59	21.1%	91.3
19	2.86	2.49	0.37	12.8%	89.8
20	2.69	2.42	0.27	10.0%	88.1
21	2.55	2.32	0.24	9.2%	84.7
22	2.37	2.81	(0.44)	-18.5%	81.5
23	2.12	2.27	(0.15)	-7.2%	79.4
24	1.77	1.85	(0.08)	-4.7%	77.9
Daily	Reference Load kWh	Estimated Load w/ DR kWh	Energy Savings kWh Δ	% Change	Avg. Daily Weighted Temp F
	38.78	36.98	1.80	4.6%	82.6

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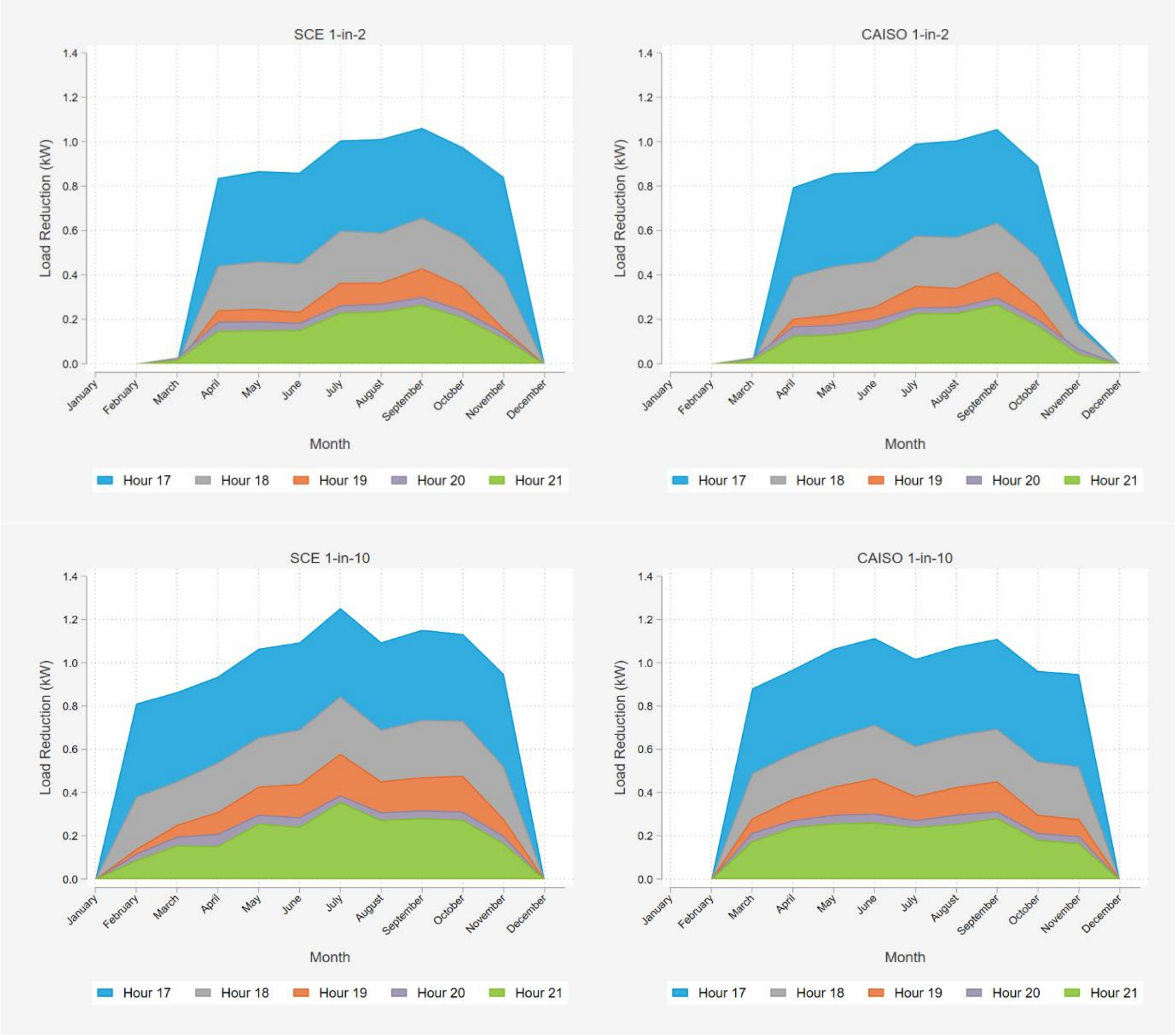
EX ANTE IMPACTS

Aggregate Impacts – Typical Event Day

By 2031 SEP is expected to be a ~ 170 MW resource during the first hour of dispatch. ~ 80 MW average over RA window

Event impacts peak in warmer months but decline with each event hour in all months

Per Customer Impacts by Month



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Discussion

- Contract issues have been solved, mitigating the available for dispatch issues from 2020
- The extreme weather conditions of summer 2020 highlighted the value of weather-sensitive programs like SEP as a grid resource.
- SEP does not hold a consistent load shed under the current event profile.
  - Variable impact profile across an event creates considerations for dispatch and valuation.
  - During summer 2020, several vendors tested strategies to produce a more consistent load impact across dispatch hours.

Recommendations

- We estimated slightly **higher** reference loads under COVID and slightly **lower** load impacts holding other conditions constant.
  - In the ex ante projections, the COVID effect is gradually withdrawn from 2021 to 2031. The COVID index will need to be continually updated to reflect behaviors and trends as vaccinations and other COVID factors progress.
- Rollout of default TOU pricing for residential customers is underway in SCE territory. Nearly 28% of SEP participants faced time-varying pricing during PY2020.
  - Continue to monitor the effect of TOU on SEP participant reference loads and load impacts.
- Continue exploring opportunities for increased coordination with energy efficiency and the ability to enroll CCA customers

QUESTIONS?

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SOUTHERN CALIFORNIA EDISON SUMMER DISCOUNT PLAN: 2020 LOAD IMPACT EVALUATION

APRIL 29, 2021

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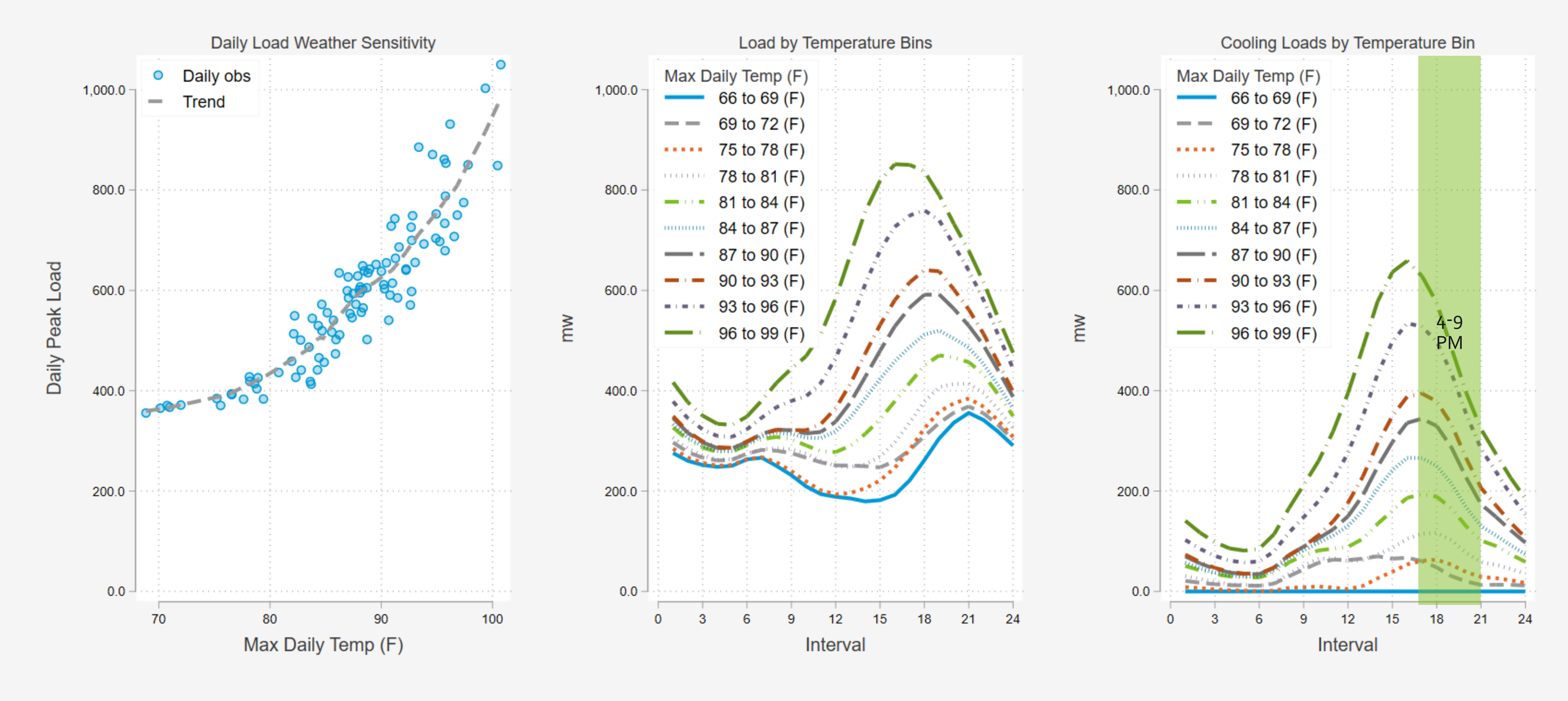
SDP PARTICIPANT CHARACTERISTICS AND LOADS

THE SDP PROGRAM IS AN AC CYCLING PROGRAM. EVENTS ARE DISPATCHED BY GEOGRAPHICALLY DEFINED REGIONAL SUBGROUPS

- ~80% of participants, tonnage, and devices are in 100% cycling
- ~50% of resources are in the SCE-Central SubLAP
- ~12% of participants have solar
- ~27% of SDP-R participants are low income (CARE or FERA)
- Schools and religious organizations account for 80% of SDP-C tonnage

Sector	Cycling Strategy	Number of Accounts	Share of Accounts	Number of Devices	Share of Devices	Total Tonnage	Share of Tonnage
Residential	50%	30,207		33,698		120,887	
	100%	175,499		206,257		751,206	
Commercial	30%	640		3,469		18,591	
	50%	2,253		24,648		120,304	
	100%	5,400		45,262		230,679	
Total		**213,999**		**313,334**		**1,241,667**	

SDP PARTICIPANTS HAVE OVER 600 MW OF COOLING LOAD WHEN TEMPERATURES ARE HOT



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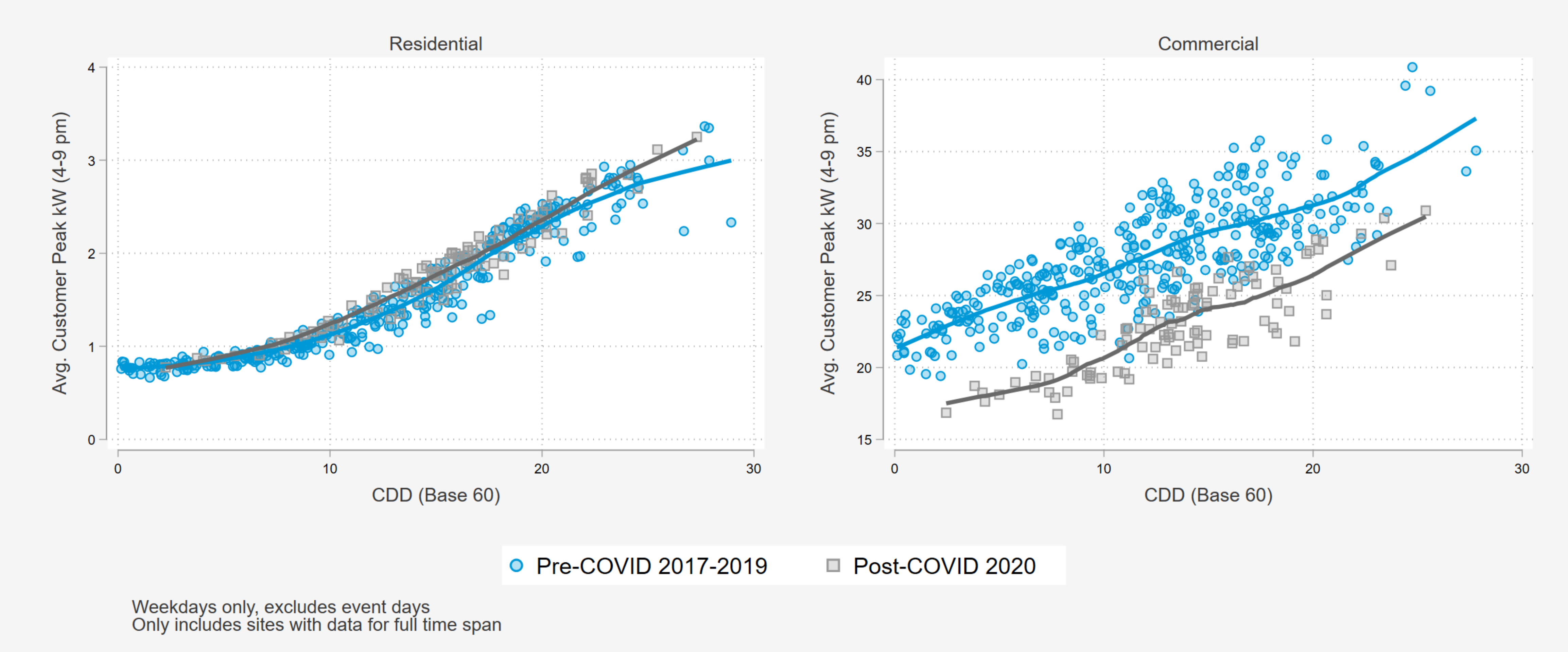
RESIDENTIAL LOADS WERE 9% HIGHER AND COMMERCIAL LOADS WERE 25% LOWER THAN THEY WERE PRIOR TO COVID



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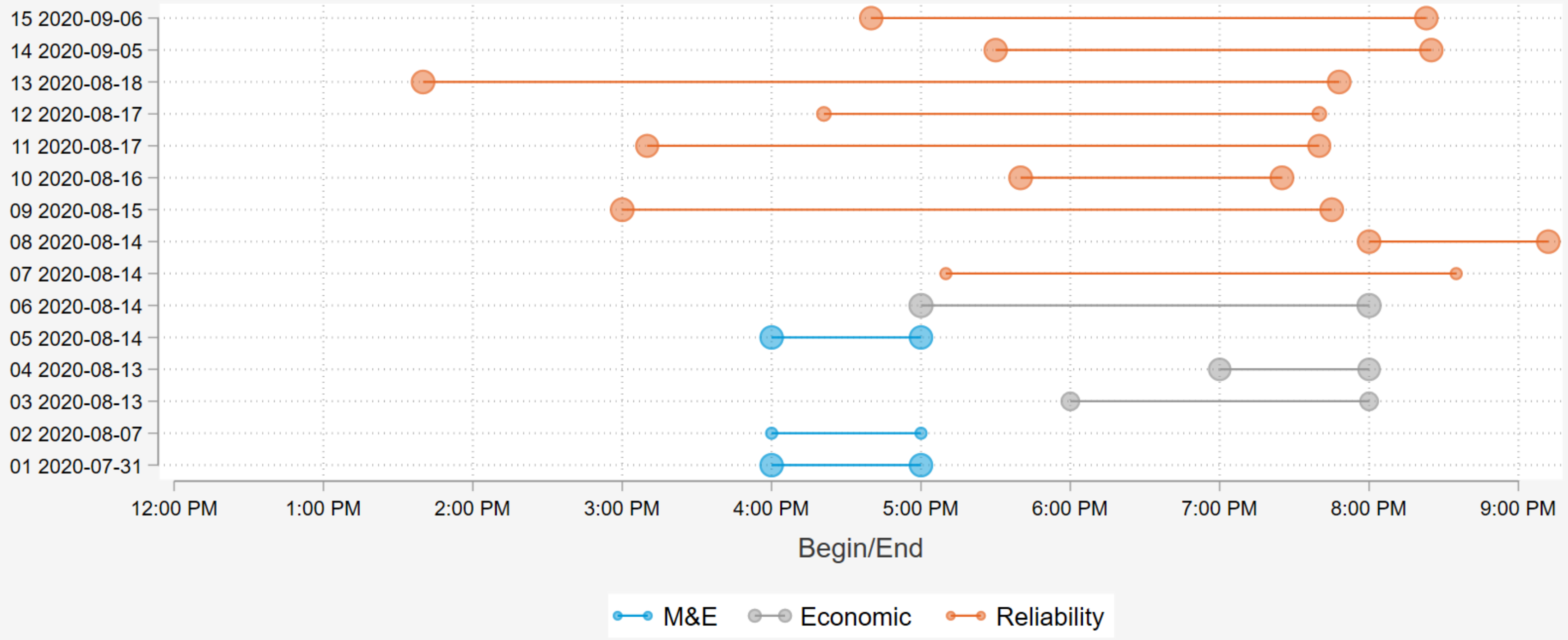
2020 EVALUATION RESULTS

2020 EVENTS VARIED IN TIMING AND TARGETED DISPATCH BY SUBLAP



Size of bubbles is proportional to the number of participants dispatched.

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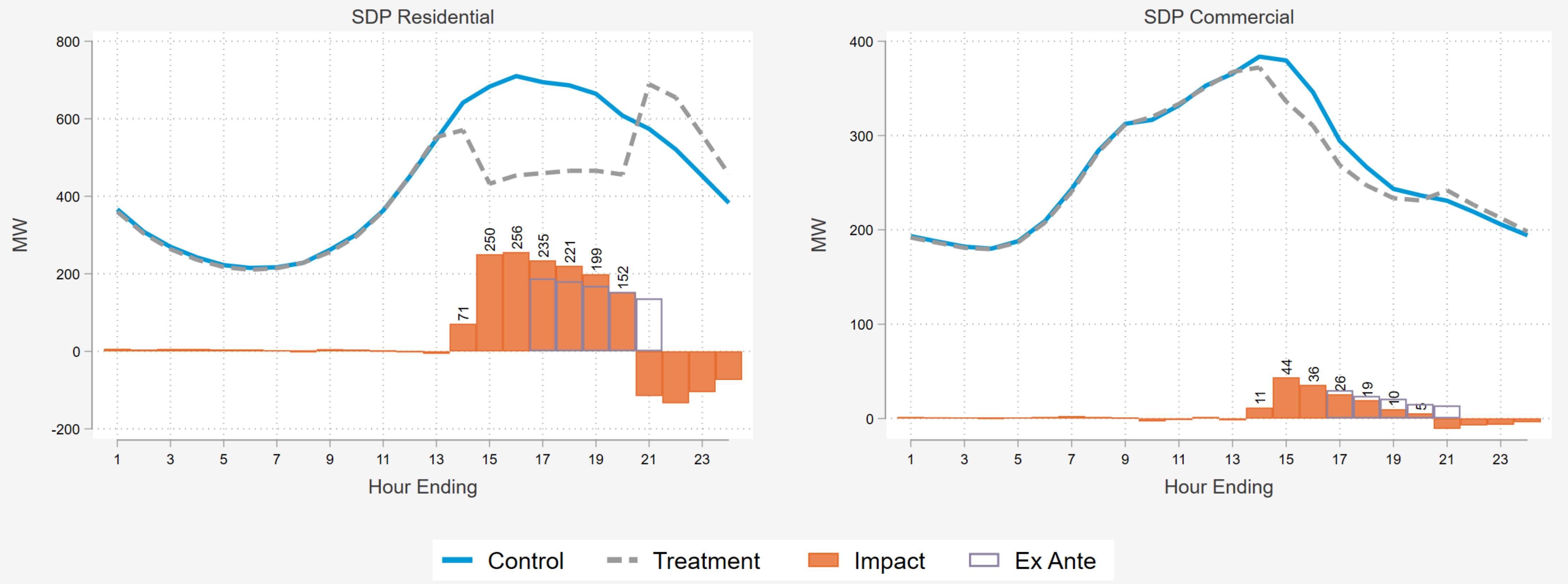
LOAD IMPACTS ON THE PEAK DAY (AUGUST 18TH)



Event hours: 13:40 - 19:48
The ex ante reference bars represent 1-in-2 weather conditions for the August monthly peak day (vintage year 2019, forecast year 2020)

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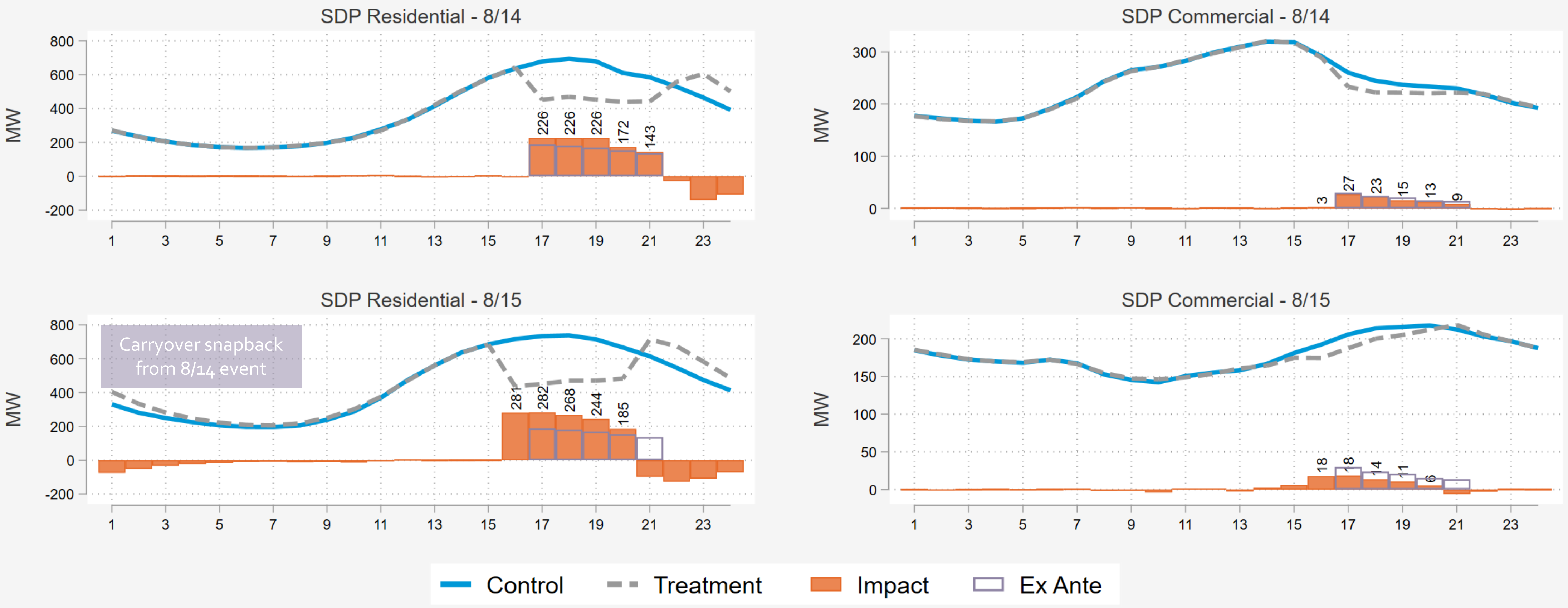
CAISO STAGE 3 EMERGENCY DAYS (AUGUST 14TH AND 15TH)



The ex ante reference bars represent 1-in-2 weather conditions for the August monthly peak day (vintage year 2019, forecast year 2020)

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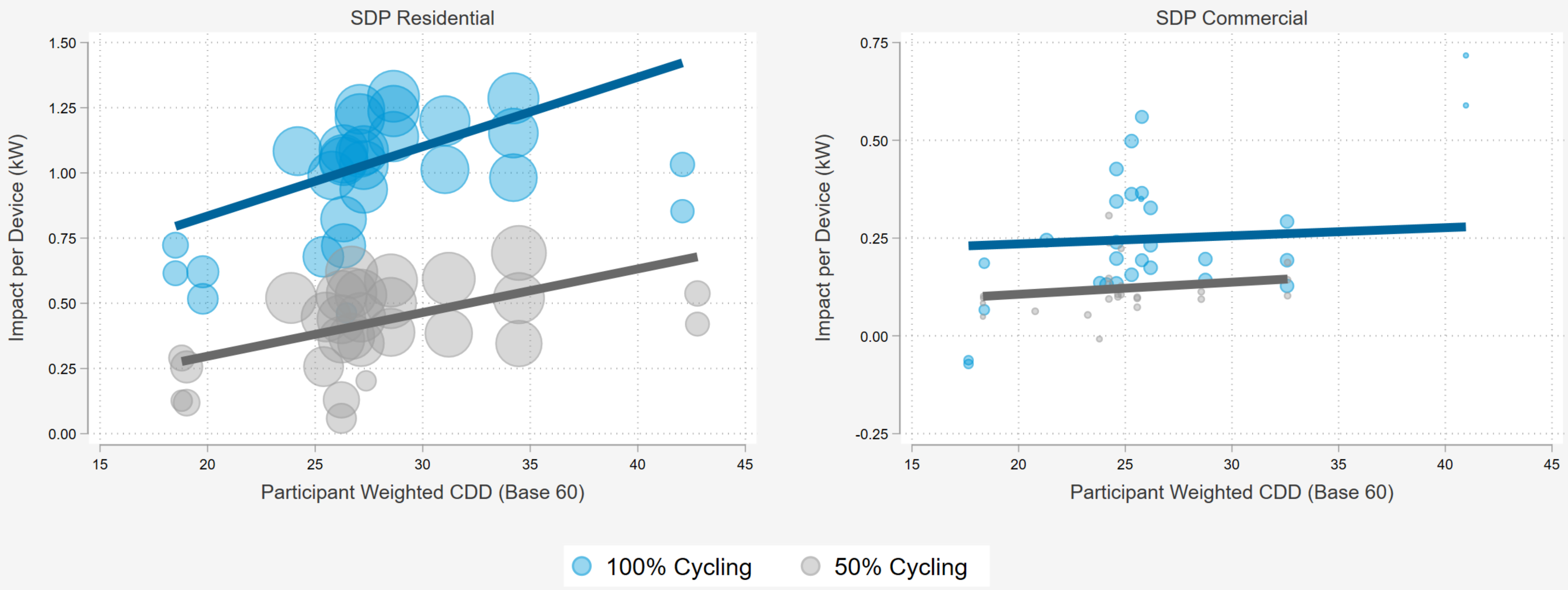
IMPACTS FOR KEY SEGMENTS – CYCLING STRATEGY



Partial event hours are not included, and only event hours during peak period (4-9pm) are shown.
Bubble size is scaled to aggregate MW reduction.

EX-ANTE IMPACTS – FORECAST YEAR 2021 LOAD IMPACTS ON THE 1-IN-2 AUGUST PEAK DAY

Table 1: Menu options

Program	SDP-R
Type of result	Aggregate
Category	ALL
Subcategory	All
Weather Data	SCE Weather
Weather Year	1-in-2
Day Type	MONTHLY SYSTEM PEAK DAY
Month	8
Forecast Year	2021

Table 2: Event day information

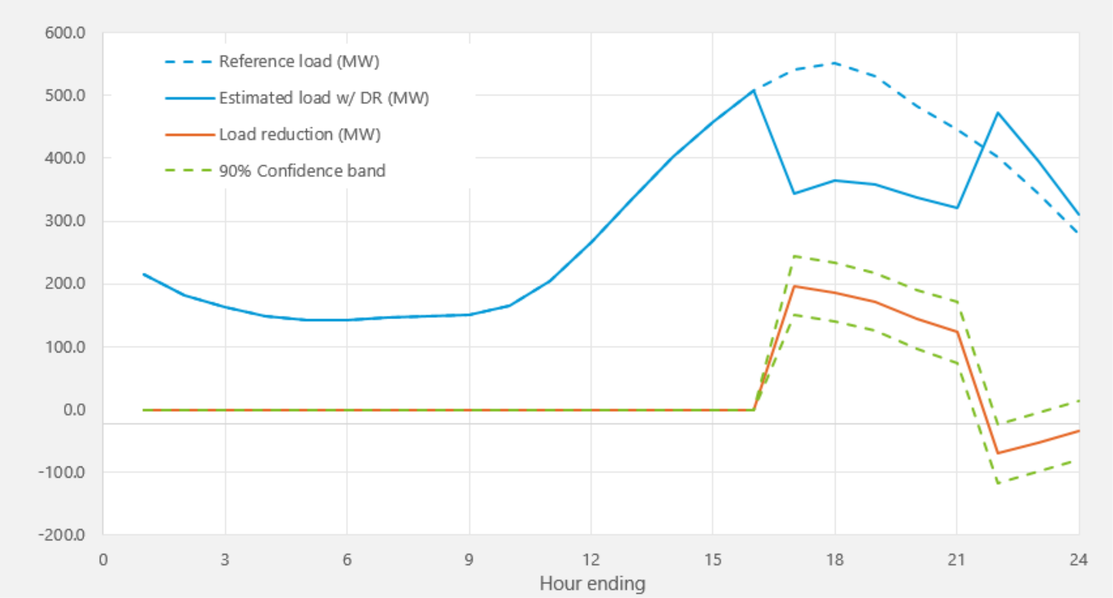
Event start	4:00 PM
Event end	9:00 PM
Total sites	189,795
Total devices	221,618
Total AC tonnage	808,299
Event window temperature (F)	91.3
Event window load reduction (MW)	164.59
% Load reduction (Event window)	32.3%
COVID Index	0.50

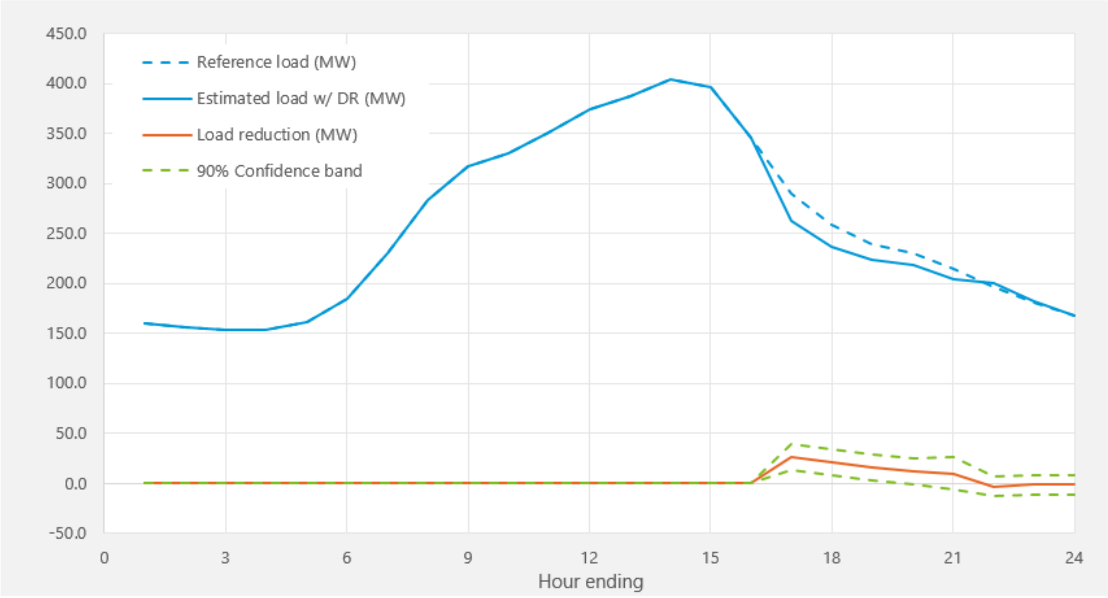
Table 1: Menu options

Program	SDP-C
Type of result	Aggregate
Category	ALL
Subcategory	All
Weather Data	SCE Weather
Weather Year	1-in-2
Day Type	MONTHLY SYSTEM PEAK DAY
Month	8
Forecast Year	2021

Table 2: Event day information

Event start	4:00 PM
Event end	9:00 PM
Total sites	7,457
Total devices	64,890
Total AC tonnage	327,395
Event window temperature (F)	88.9
Event window load reduction (MW)	17.11
% Load reduction (Event window)	6.9%
COVID Index	0.50





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RA WINDOW EX-ANTE AGGREGATE LOAD REDUCTIONS

SDP Residential

Forecast Year	Enrollment Forecast	SCE Weather		CAISO Weather	
		1-in-2	1-in-10	1-in-2	1-in-10
2021	189,795	165	189	164	178
2022	191,614	167	192	166	181
2023	183,372	160	184	159	173
2024	173,446	151	174	150	164

SDP Commercial

Forecast Year	Enrollment Forecast	Total Devices	SCE Weather		CAISO Weather	
			1-in-2	1-in-10	1-in-2	1-in-10
2021	7,457	64,890	17.1	20.1	16.8	19.8
2022	6,776	58,694	17.1	20.6	16.9	19.6
2023	6,163	53,630	16.3	19.5	16.1	18.6
2024	5,611	48,826	15.2	18.1	15.0	17.3

SDP-R EX-ANTE COMPARISON TO EX-POST

Unit	Date	Accounts	Devices	Max Daily Temp (F)	Avg. Daily Temp (F)	4:00-5:00 PM	5:00-6:00 PM	6:00-7:00 PM	7:00-8:00 PM	8:00-9:00 PM
Aggregate Impact MW	2020-08-18	199,557	232,734	102.6	87.2	234.6	220.5	198.6	---	---
	2020-09-05	191,475	223,465	109.3	91.1	---	---	248.5	206.0	---
	2020-09-06	191,475	223,465	109.9	94.3	---	268.3	237.2	198.9	---
	SCE Ex ante 1-in-10 August Peak Day	189,795	221,618	99.4	86.8	222.1	213.3	198.0	167.8	145.8
	SCE Ex ante 1-in-2 August Peak Day	189,795	221,618	95.4	84.2	197.4	186.7	171.3	144.2	123.5
Impact per Device	2020-08-18	199,557	232,734	102.6	87.2	1.01	0.95	0.85	---	---
	2020-09-05	191,475	223,465	109.3	91.1	---	---	1.11	0.92	---
	2020-09-06	191,475	223,465	109.9	94.3	---	1.20	1.06	0.89	---
	SCE Ex ante 1-in-10 August Peak Day	189,795	221,618	99.4	86.8	1.00	0.96	0.89	0.76	0.66
	SCE Ex ante 1-in-2 August Peak Day	189,795	221,618	95.4	84.2	0.89	0.84	0.77	0.65	0.56

- 8/18 was the system peak day; 9/5 and 9/6 ranked third and fourth and were both weekend days
- Ex post impacts on 9/5 and 9/6 exceed the ex ante impacts but the temperatures also exceed ex ante temperatures

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SDP-C EX-ANTE COMPARISON TO EX-POST

Unit	Date	Accounts	Devices	Max Daily Temp (F)	Avg. Daily Temp (F)	4:00-5:00 PM	5:00-6:00 PM	6:00-7:00 PM	7:00-8:00 PM	8:00-9:00 PM
Aggregate Impact MW	2020-08-14	8,255	73,296	98.2	84.8	27.7	22.5	15.5	13.0	---
	2020-08-17	8,150	72,252	95.2	83.6	---	15.5	9.0	---	---
	2020-08-18	8,160	72,372	100.7	85.1	25.6	19.4	9.8	---	---
	SCE Ex ante 1-in-10 August Peak Day	7,457	64,890	96.1	84.2	30.3	24.9	19.8	15.9	13.5
	SCE Ex ante 1-in-2 August Peak Day	7,457	64,890	92.7	82.1	26.3	21.1	16.1	12.2	9.9
Impact per Device	2020-08-14	8,255	73,296	98.2	84.8	0.37	0.31	0.21	0.18	---
	2020-08-17	8,150	72,252	95.2	83.6	---	0.21	0.12	---	---
	2020-08-18	8,160	72,372	100.7	85.1	0.36	0.27	0.14	---	---
	SCE Ex ante 1-in-10 August Peak Day	7,457	64,890	96.1	84.2	0.47	0.38	0.31	0.24	0.21
	SCE Ex ante 1-in-2 August Peak Day	7,457	64,890	92.7	82.1	0.41	0.32	0.25	0.19	0.15

- PY 2018 had 3 events at temperatures in the range of the ex-ante conditions
- Comparing per account and per device impacts shows that not much extrapolation was needed

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EX-ANTE COMPARISON TO PRIOR YEARS – PER CUSTOMER IMPACTS

Month	SDP-Residential				SDP-Commercial			
	PY2019		PY2020		PY2019		PY2020	
	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10
June	1.90	2.99	1.91	2.52	0.37	0.94	0.53	0.97
July	2.56	3.56	2.44	3.52	0.71	1.14	0.81	1.13
August	2.58	2.95	2.29	2.80	0.80	0.95	0.87	1.00
September	2.76	3.12	2.65	2.96	0.82	0.99	0.88	1.02

MAIN DIFFERENCES

- Different historical years
  - PY 2020 relied on data from 2018-2020
  - PY 2019 relied on data from 2018-2019
- Different participants – SCE removes low performing sites annually
- Different models
  - PY 2019 used both daily heat build up (as defined above) and short term build up. It also included different slopes by LCG/cycling group
  - PY 2020 included temperature splines and a number of interacted variables

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DATA DRIVEN RESEARCH AND INSIGHTS

QUESTIONS?

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APPLIED ENERGY GROUP

LI Evaluation of Non-Residential Critical Peak Pricing and Peak Day Pricing

Date: April 30, 2021

Prepared for: 2021 DRMEC Load Impact Workshop

Agenda

Program Descriptions

- Descriptions and Expected Changes
- Participant Population

Ex-Post Load Impacts

- Event Summary
- Load Impacts by IOU

Ex-Ante Load Impacts

- COVID-19 Effect and Adjustment
- Load Impacts by IOU

Key Findings

- Statewide Load Impacts
- PY2020 Takeaways

Program Descriptions

Program Description

Program Basics

- Non-Residential customers only
- Statewide price responsive DR program
- Customers experience an increase in price (above existing on-peak price) during events.
- Operates year-round

Events

- Event hours are 2-6 PM (PG&E and SDG&E) and 4-9 PM (SCE)
- Number of events per year varies
  - PG&E 9 to 15
  - SCE 12
  - SDG&E maximum of 18
- Customers are notified on a day ahead basis

Expected Program Changes

PG&E

- Defaulted a group of new participants in March 2021.
- Event window changed to 5-8 PM effective March 1, 2021.
- Pending CPUC decision, the event window is expected to change to 4-9 PM at a later point.

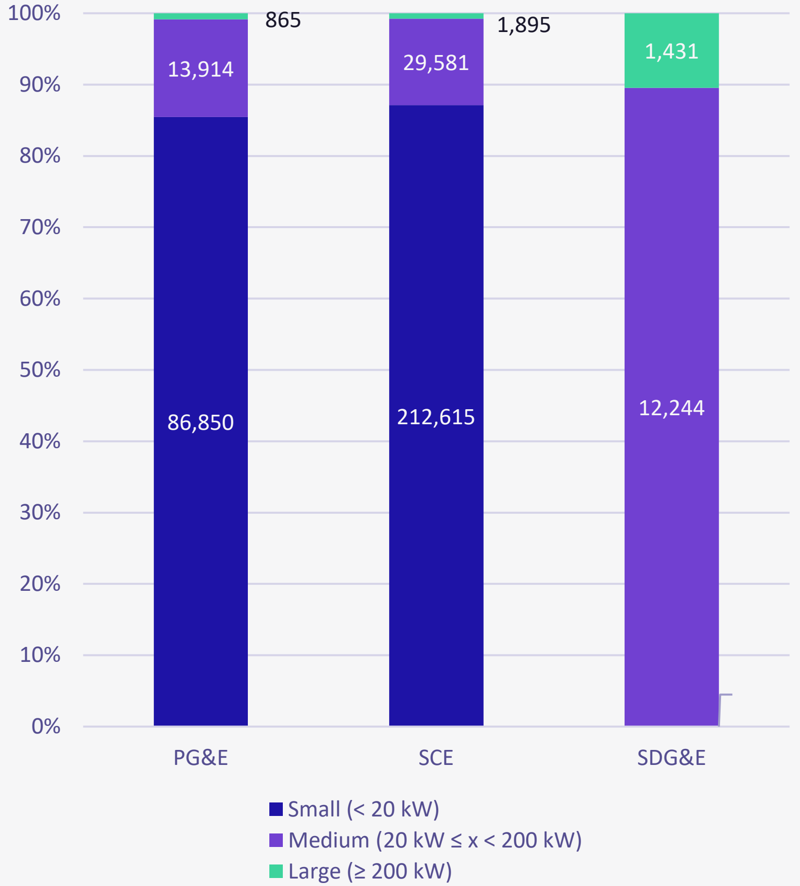
SCE

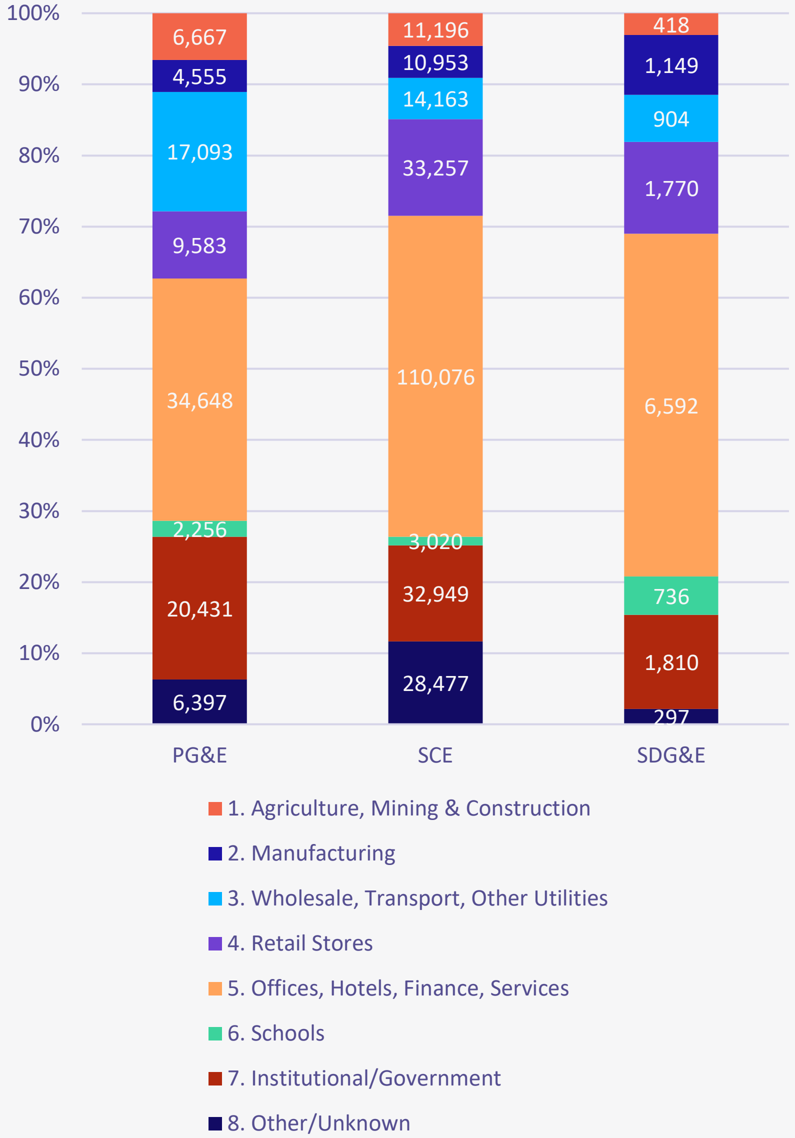
- Defaulted a group of new participants in October 2020.

SDG&E

- Anticipates a substantial decrease in participants due to migration of bundled customers to DA/CCA service.
- Event window is changing to 4-9 PM in PY2022 or PY2023, pending a new billing system.

PY2020 Participation





Ex-Post
Load Impacts

Ex-Post Analysis Approach

Subgroup-level Approach

- All IOUs and size groups are in different stages of defaulting customers.
- The design was selected based on eligible non-participants favoring the development of a control group when feasible.
- For all subgroups, regardless of design, we developed hourly fixed-effect regression models.
  - Model subgroups are by IOU, size, and industry.
  - Each model was optimized and validated using our optimization approach.

Utility	Size Group	Analysis Method
PG&E	Large	Matched Control; Customer-specific for top 10%
	Medium	Within Subjects
	Small	Within Subjects
SCE	Large	Matched Control; Customer-specific for top 5%
	Medium	Within Subjects
	Small	Within Subjects
SDG&E	Large	Within Subjects
	Medium	Within Subjects

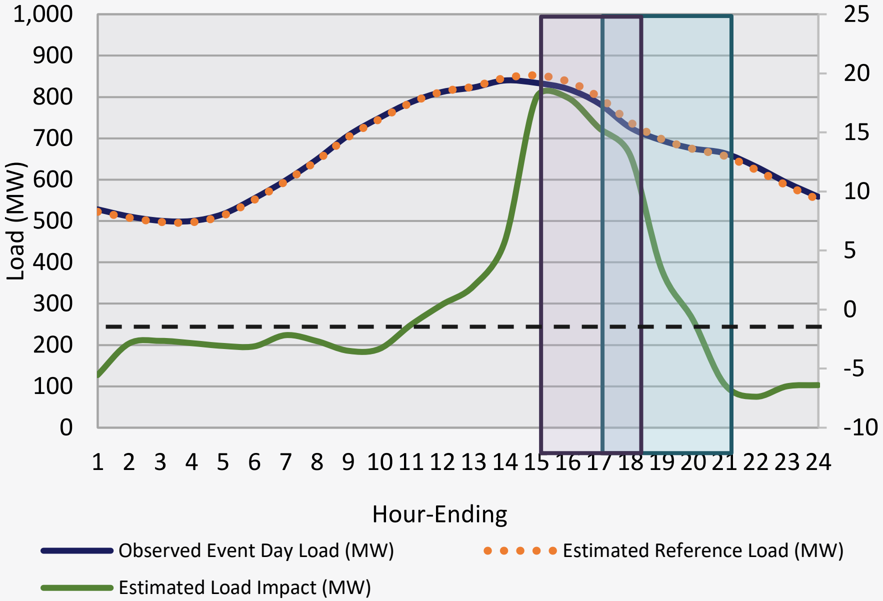
PY2020 Event Summary

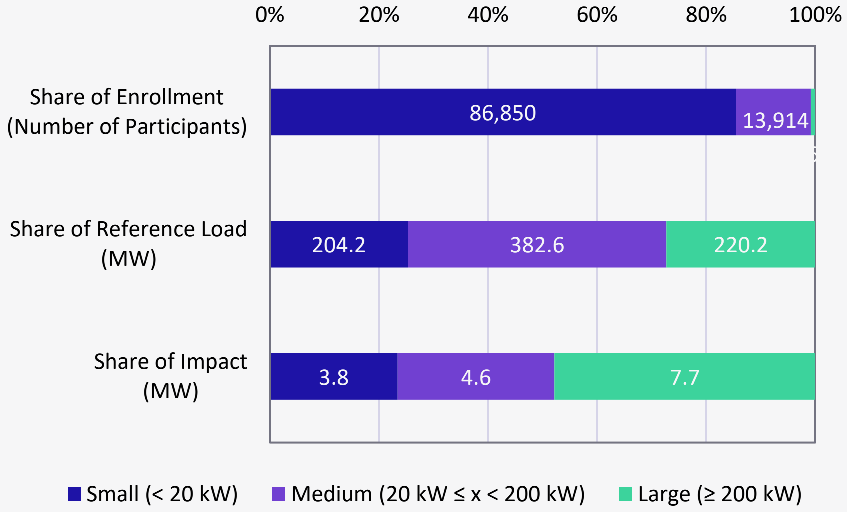
Date	Day of Week	PG&E	SCE	SDG&E
May 27	Wednesday	X		
June 24	Wednesday	X		
June 25	Thursday	X		
July 8	Wednesday		X	
July 10	Friday		X	
July 13	Monday		X	
July 15	Wednesday		X	
July 20	Monday		X	
July 27	Monday	X		
July 28	Tuesday	X		
July 30	Thursday	X		
August 3	Monday		X	
August 4	Tuesday		X	
August 10	Monday	X		
August 12	Wednesday		X	
August 13	Thursday	X	X	
August 14	Friday	X		
August 17	Monday	X	X	X
August 18	Tuesday	X	X	X
August 19	Wednesday	X	X	X
August 20	Thursday			X
September 5	Saturday			X
September 6	Sunday	X		X
September 7	Monday (Holiday)			X
September 30	Wednesday			X
October 1	Thursday			X
Total		**13**	**12**	**9**

PG&E Ex-Post Load Impacts

Top Takeaways

- Total load impact of 16.1 MW
- Medium and small had significant contributions this year



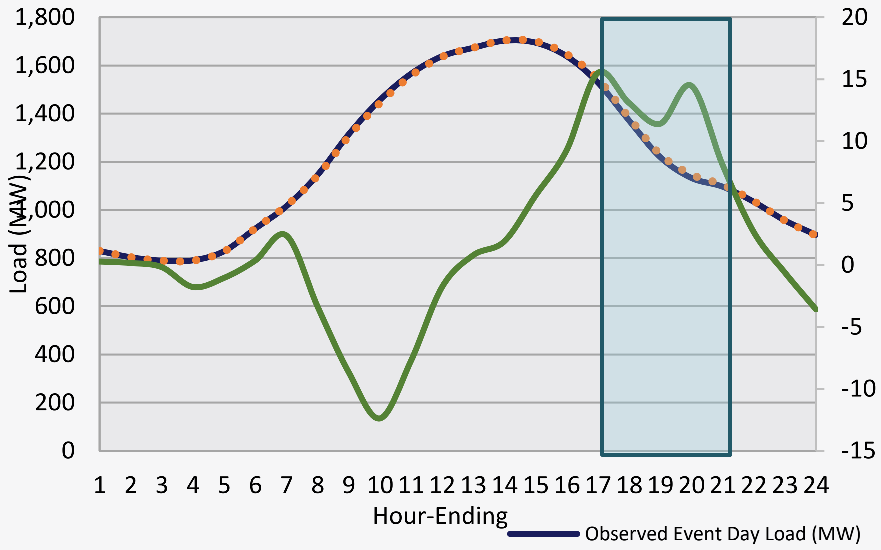


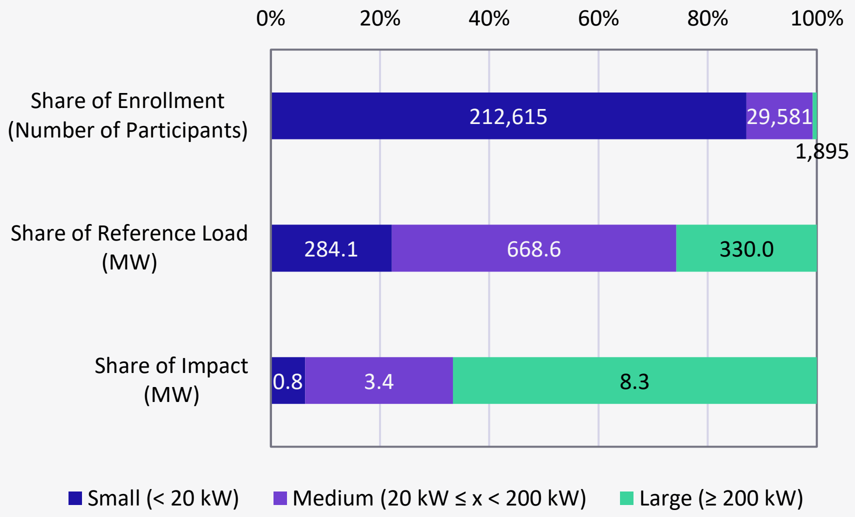
Size Group	# Enrolled	Aggregate (MW) Ref. Load	Aggregate (MW) Load Impact	% Load Impact	Avg. Event Temp.
Large	865	220.2	7.7	3.49%	96.4
Medium	13,914	382.6	4.6	1.21%	95.9
Small	86,850	204.2	3.8	1.85%	92.5
Total	**101,629**	**807.0**	**16.1**	**1.99%**	**94.8**

SCE Ex-Post Load Impacts

Top Takeaways

- Total load impact of 12.5 MW
- Medium and small had significant contributions this year
- Large %impact is back up to 2.5% in the second year of new CPP event window.



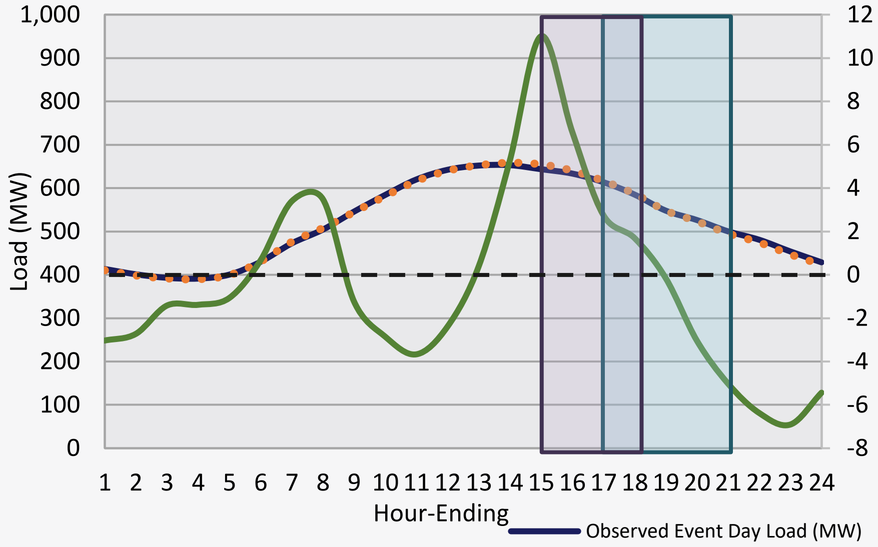


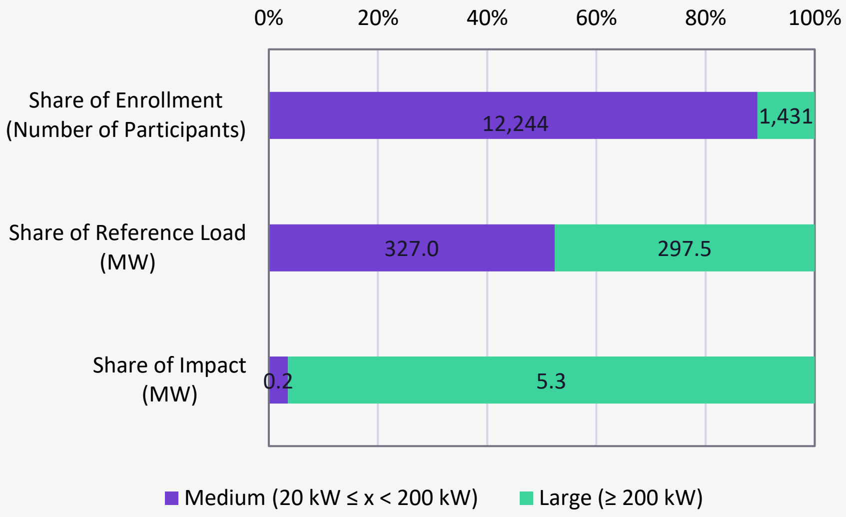
Size Group	# Enrolled	Aggregate (MW)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact		
Large	1,895	330.0	8.3	2.53%	87.2
Medium	29,581	668.6	3.4	0.51%	84.4
Small	212,615	284.1	0.8	0.28%	81.2
Total	**244,091**	**1,282.6**	**12.5**	**0.98%**	**84.6**

SDG&E Ex-Post Load Impacts

Top Takeaways

- Total load impact of 5.5 MW





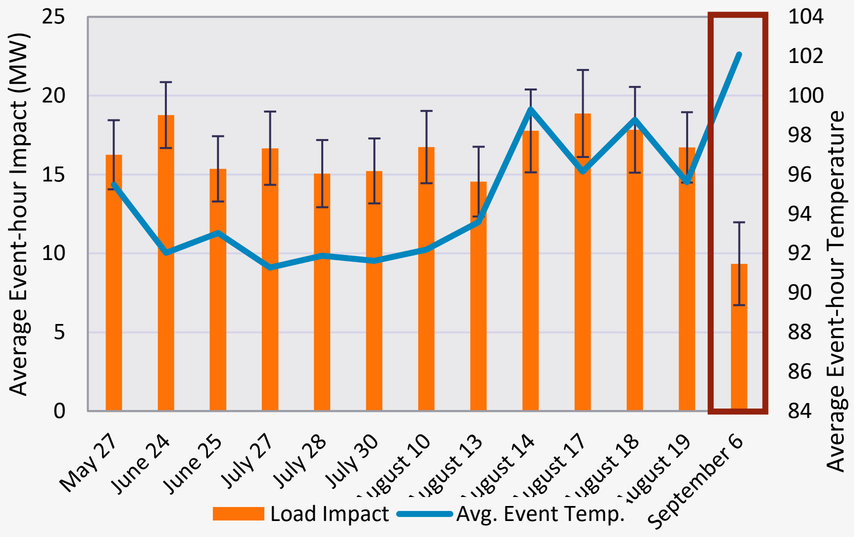
Size Group	# Enrolled	Aggregate (MW)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact		
Large	1,431	297.5	5.3	1.79%	89.4
Medium	12,244	327.0	0.2	0.06%	89.1
Total	**13,675**	**624.5**	**5.5**	**0.88%**	**89.2**

Weekend Events

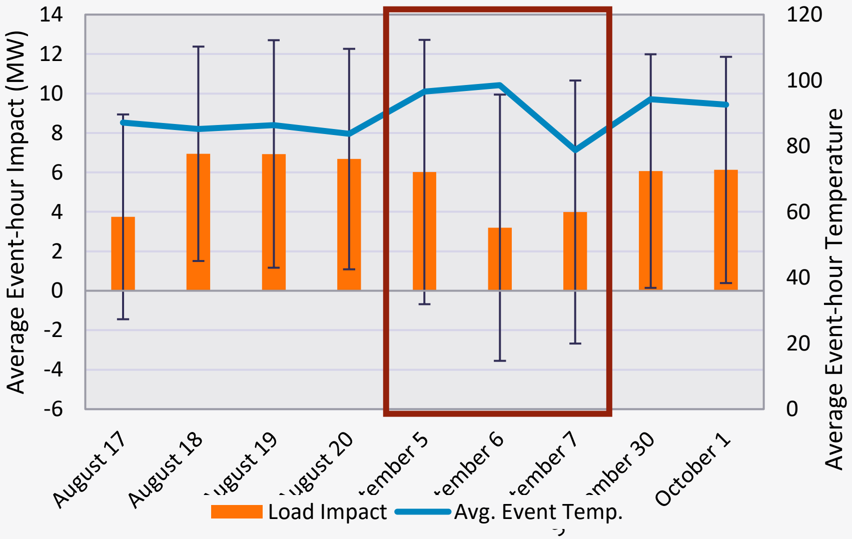
Weekend Events:

- Have less available load to curtail.
- Are more challenging to model/estimate.
- (PG&E) Delivered lower aggregate impacts compared to weekday events.
- (SDG&E) Gave insignificant load impacts (i.e., higher variances or wider confidence intervals).

PG&E PY2020 Events



SDG&E PY2020 Events

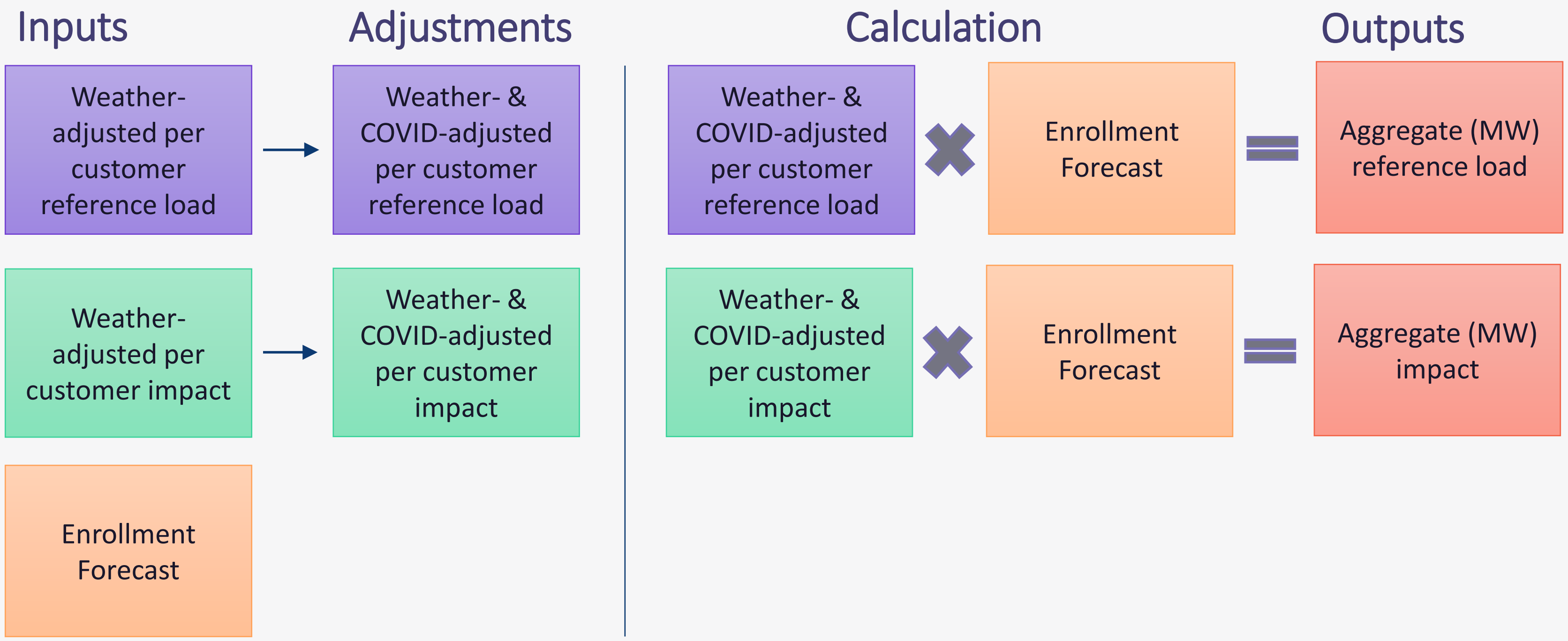


Ex-Ante
Load Impacts

Ex-Ante Analysis Approach

Goal: Develop a forecast of MW impacts and participant reference loads over the next 11 years across 4 Weather Years

- Per-customer reference loads
- Per-customer load impacts
- Enrollment forecast



Ex-Ante Approach & Assumptions

Create Annual Weather-Adjusted Reference Load

- Used ex-post regression models and inputs from weather scenarios.
- (SCE only) Non-summer months are based on June data.

Apply the COVID adjustment to Reference Load

- Estimated the COVID effect for each group using a simple regression approach.
- Added back the COVID effect to the weather-adjusted reference loads to create a “no-COVID” case.
- Applied the IOU-specific factors to remove the COVID effect over time.

Calculate the Per-customer Load Impacts

- Estimated the weather-adjusted per-customer impacts using ex-post regression models and inputs from weather scenarios.
- Incorporated the COVID adjustment by calculating the new load impacts as a percent of the COVID-adjusted reference loads.

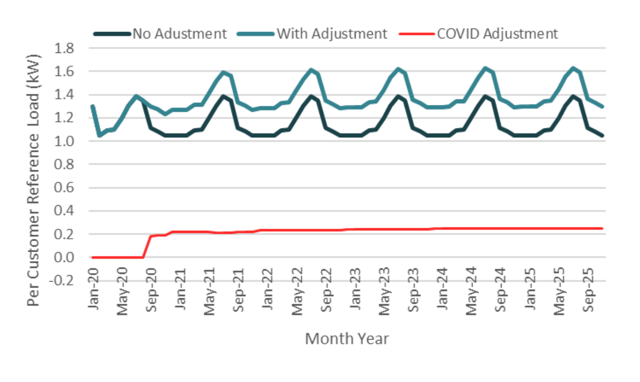
Apply the enrollment forecast

- Assumed zero impacts for 1st year defaulted customers.
- Multiplied per-customer load impacts by enrollment forecast to arrive at the aggregate forecast.

COVID Adjustment Example

(SCE)

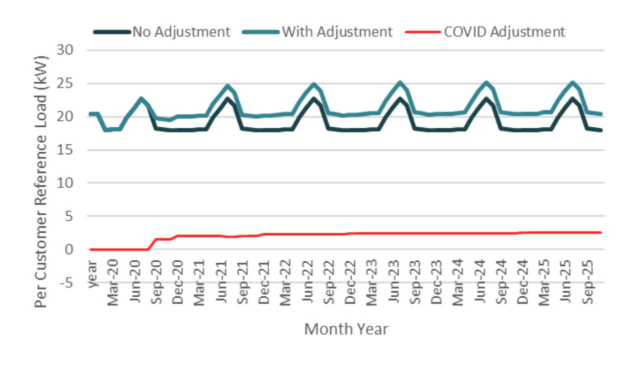
SMALL



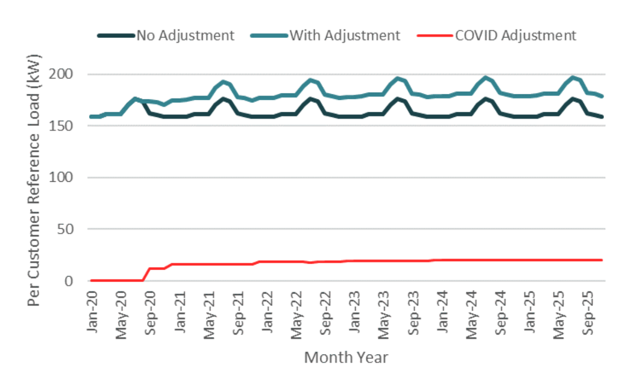
Year / Month	Enroll. Forecast	No Adj	With Adj	Diff
Aug-20	212,604	1.38	1.38	0.00
Aug-21	225,092	1.38	1.59	0.21
Aug-22	227,294	1.38	1.61	0.23
Aug-23	235,661	1.38	1.62	0.24
Aug-24	244,028	1.38	1.63	0.25
Aug-25	252,396	1.38	1.63	0.25

MEDIUM

Year / Month	Enroll. Forecast	No Adj	With Adj	Diff
Aug-20	29,571	22.70	22.70	0.00
Aug-21	28,560	22.70	24.64	1.93
Aug-22	28,841	22.70	24.94	2.24
Aug-23	29,901	22.70	25.09	2.39
Aug-24	30,964	22.70	25.17	2.46
Aug-25	32,027	22.70	25.20	2.50

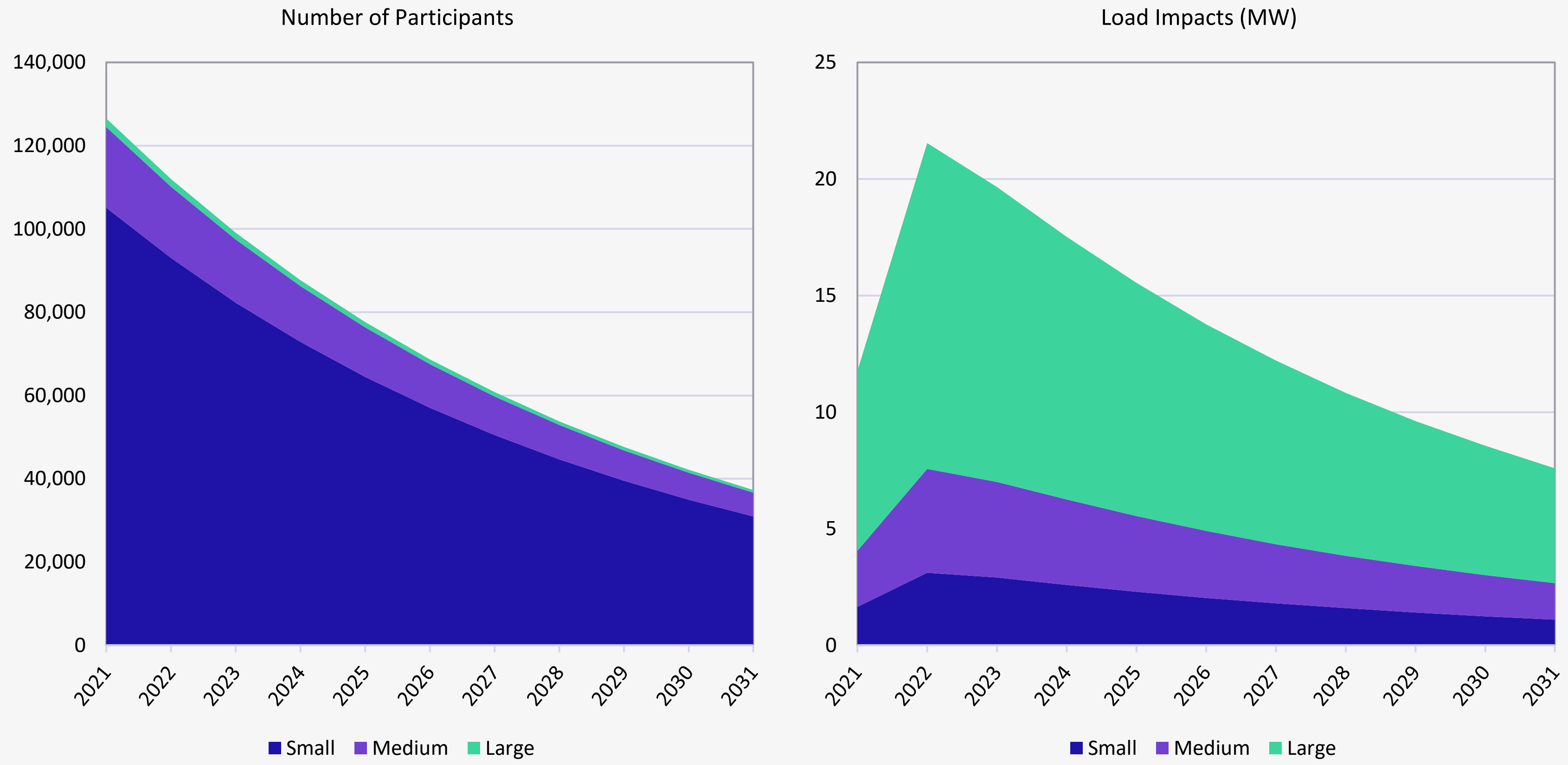


LARGE



Year / Month	Enroll. Forecast	No Adj	With Adj	Diff
Aug-20	1,891	176.66	176.66	0.00
Aug-21	1,905	176.62	192.40	15.78
Aug-22	1,922	176.63	194.78	18.14
Aug-23	1,994	176.63	195.96	19.33
Aug-24	2,065	176.63	196.55	19.92
Aug-25	2,136	176.62	196.84	20.21

PG&E Ex-Ante Forecast

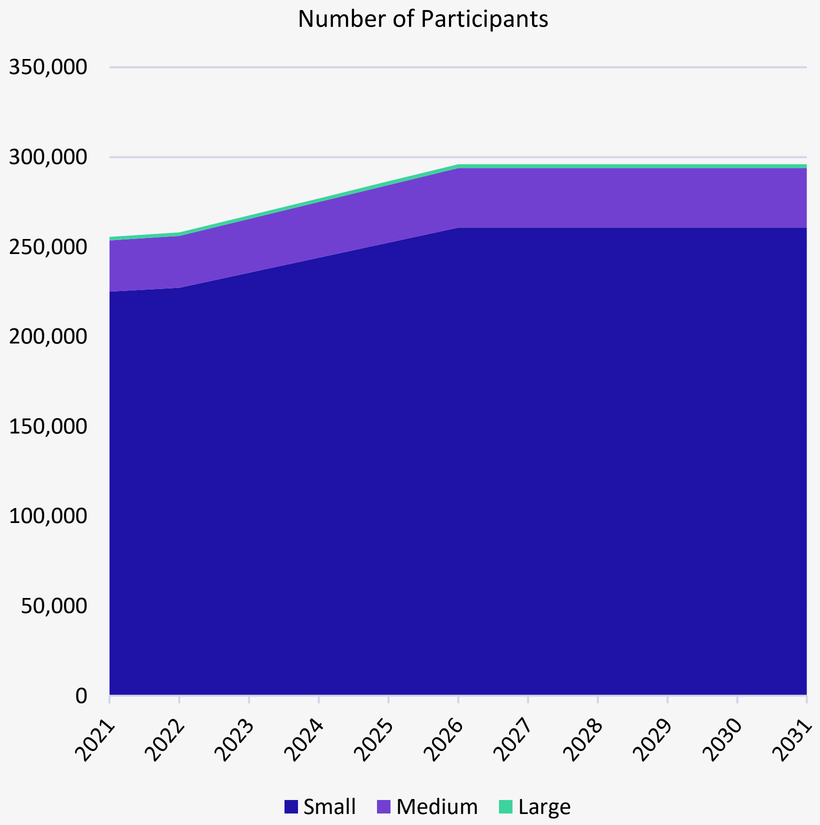


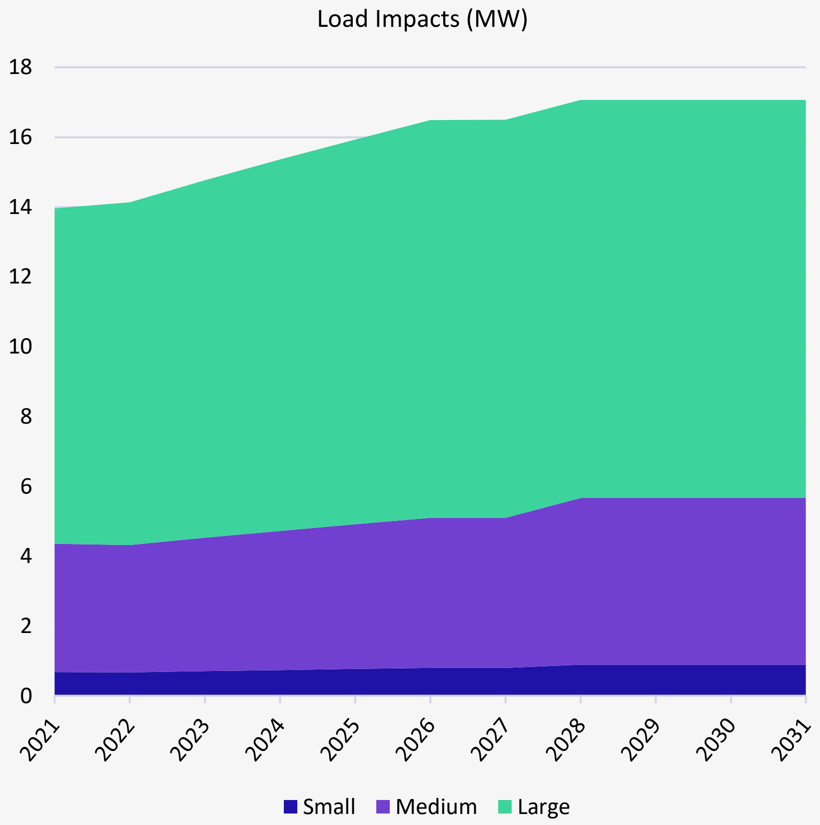
PG&E Ex-Ante

PY2019 v. PY2020

	Size	# Enrolled	Aggregate (MW) Ref. Load	Aggregate (MW) Load Impact	Per-Customer (kW) Ref. Load	Per-Customer (kW) Load Impact	% Load Impact	Avg. Event Temp.
PY2019 Ex-Ante	Large	2,570	789.6	10.7	307.3	4.2	1.36%	94
PG&E 1-in-2	Medium	33,456	677.1	-1.6	20.2	0.0	-0.24%	94
Typical Event Day 2021	Small	127,703	193.8	-0.8	1.5	0.0	-0.40%	93
	All	**163,729**	**1,660.5**	**8.3**	**10.1**	**0.1**	**0.50%**	**93**
PY2020 Ex-Ante	Large	2,106	590.9	7.7	280.6	3.7	1.31%	96
PG&E 1-in-2	Medium	19,352	479.7	2.4	24.8	0.1	0.50%	96
Typical Event Day 2021	Small	105,124	214.2	1.6	2.0	0.0	0.77%	94
	All	**126,582**	**1,284.8**	**11.8**	**10.1**	**0.1**	**0.92%**	**94**
PY2020 Ex-Ante	Small	1,465	431.1	11.3	294.2	7.7	2.61%	96
PG&E 1-in-2	Medium	13,416	365.0	3.7	27.2	0.3	1.00%	96
Typical Event Day 2024	Large	72,840	168.3	2.6	2.3	0.0	1.54%	94
	All	**87,721**	**964.4**	**17.5**	**11.0**	**0.2**	**1.82%**	**94**

SCE Ex-Ante Forecast



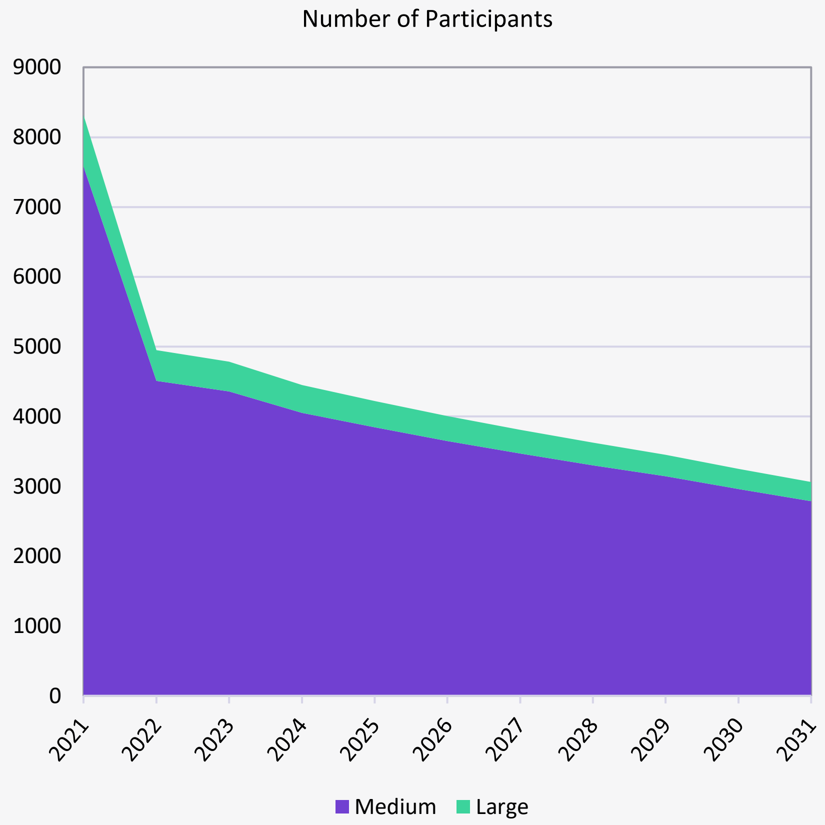


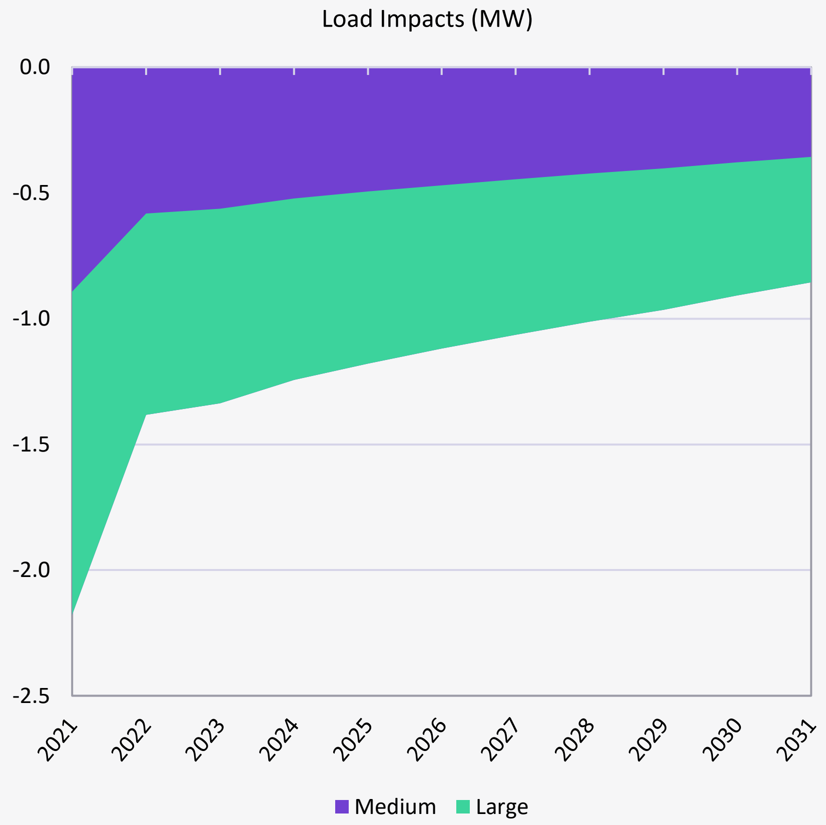
SCE Ex-Ante

PY2019 v. PY2020

	Size	# Enrolled	Aggregate (MW) Ref. Load	Aggregate (MW) Load Impact	Per-Customer (kW) Ref. Load	Per-Customer (kW) Load Impact	% Load Impact	Avg. Event Temp.
PY2019 Ex-Ante	Large	2,525	498.2	8.0	197.3	3.2	1.60%	88
SCE 1-in-2	Medium	30,298	750.1	0.0	24.8	0.0	0.00%	88
Typical Event Day 2020	Small	219,658	328.9	0.0	1.5	0.0	0.00%	87
	All	**252,481**	**1,577.2**	**8.0**	**6.2**	**0.0**	**0.51%**	**87**
PY2020 Ex-Ante	Large	1,892	334.2	8.8	176.6	4.6	2.62%	88
SCE 1-in-2	Medium	29,571	670.1	3.8	22.7	0.1	0.57%	87
Typical Event Day 2020	Small	212,604	292.9	0.6	1.4	0.0	0.21%	87
	All	**244,067**	**1,297.2**	**13.2**	**5.3**	**0.1**	**1.02%**	**87**
PY2020 Ex-Ante	Small	2,136	420.4	11.0	196.8	5.2	2.62%	88
SCE 1-in-2	Medium	32,027	805.8	4.1	25.2	0.1	0.51%	87
Typical Event Day 2025	Large	252,396	410.2	0.8	1.6	0.0	0.19%	87
	All	**286,559**	**1,636.5**	**15.9**	**5.7**	**0.1**	**0.97%**	**87**

SDG&E Ex-Ante Forecast





SDG&E Ex-Ante

PY2019 v. PY2020

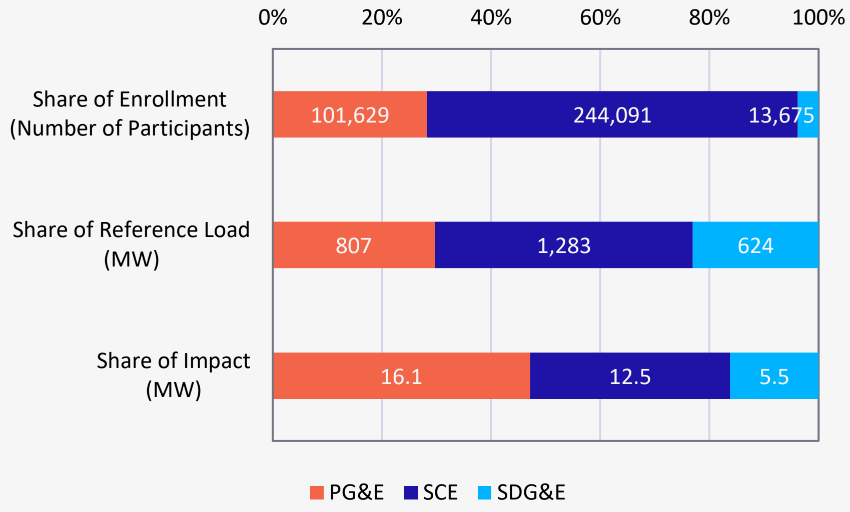
	Size	# Enrolled	Aggregate (MW) Ref. Load	Aggregate (MW) Load Impact	Per-Customer (kW) Ref. Load	Per-Customer (kW) Load Impact	% Load Impact	Avg. Event Temp.
PY2019 Ex-Ante	Large	1,289	230.9	3.3	179.1	2.5	1.42%	80.9
SDG&E 1-in-2	Medium	12,840	285.4	-1.2	22.2	-0.1	-0.41%	80.7
Typical Event Day 2020	**All**	**14,129**	**516.3**	**2.1**	**36.5**	**0.1**	**0.41%**	**80.7**
PY2020 Ex-Ante	Large	1,427	277.9	2.3	194.7	1.6	0.84%	80.9
SDG&E 1-in-2	Medium	12,179	289.7	-3.2	23.8	-0.3	-1.09%	80.7
Typical Event Day 2020	**All**	**13,606**	**567.6**	**-0.8**	**41.7**	**-0.1**	**-0.15%**	**80.8**
PY2020 Ex-Ante	Small	440	96.1	0.8	218.3	1.8	0.83%	80.9
SDG&E 1-in-2	Medium	4,510	125.1	-1.4	27.7	-0.3	-1.10%	80.7
Typical Event Day 2022	**All**	**4,950**	**221.2**	**-0.6**	**44.7**	**-0.1**	**-0.26%**	**80.8**

Key Findings

Statewide Ex-Post Load Impacts

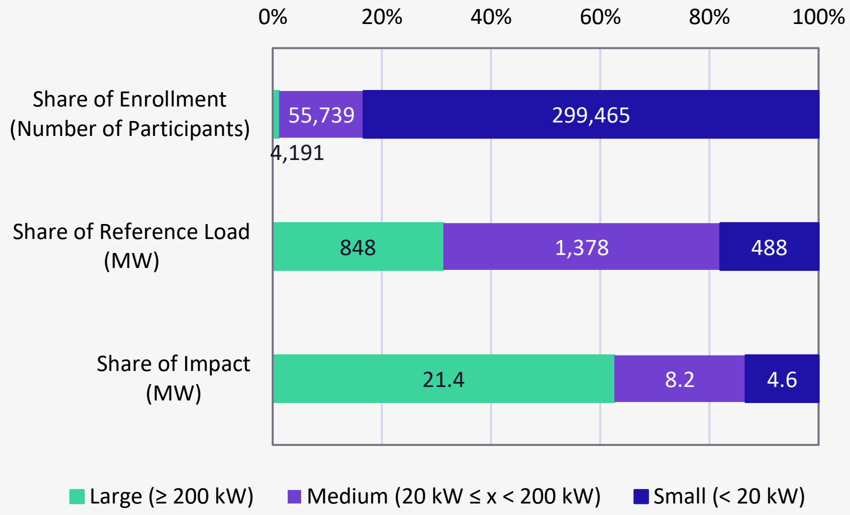
Impacts by Utility

IOU	# Enrolled	Aggregate (MW)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact		
PG&E	101,629	807	16.1	1.99%	95
SCE	244,091	1,283	12.5	0.98%	85
SDG&E	13,675	624	5.5	0.88%	89
Total	**359,395**	**2,714**	**34.1**	**1.26%**	**88**



Impacts by Size

Size Group	# Enrolled	Aggregate (MW)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact		
Large	4,191	848	21.4	2.52%	90
Medium	55,739	1,378	8.2	0.60%	88
Small	299,465	488	4.6	0.93%	84
Total	**359,395**	**2,714**	**34.1**	**1.26%**	**85**



Statewide System Peak Hour

August 18, 2021 – HE16

Utility	# Enrolled	Ref. Load (MW)	Load Impact (MW)	% Load Impact	Event Temp
PG&E - PDP	101,647	933.3	20.4	2.19%	99
SCE - CPP	-	-	-	-	-
SDG&E - CPP	13,605	668.9	7.7	1.15%	86
Statewide	**115,252**	**1,602.2**	**28.1**	**1.75%**	**97**

Statewide Ex-Ante Load Impacts

Impacts by Utility

IOU	# Enrolled	Aggregate (MW) Ref. Load	Aggregate (MW) Load Impact	% Load Impact	Avg. Event Temp.
PG&E	101,629	807	16.1	1.99%	95
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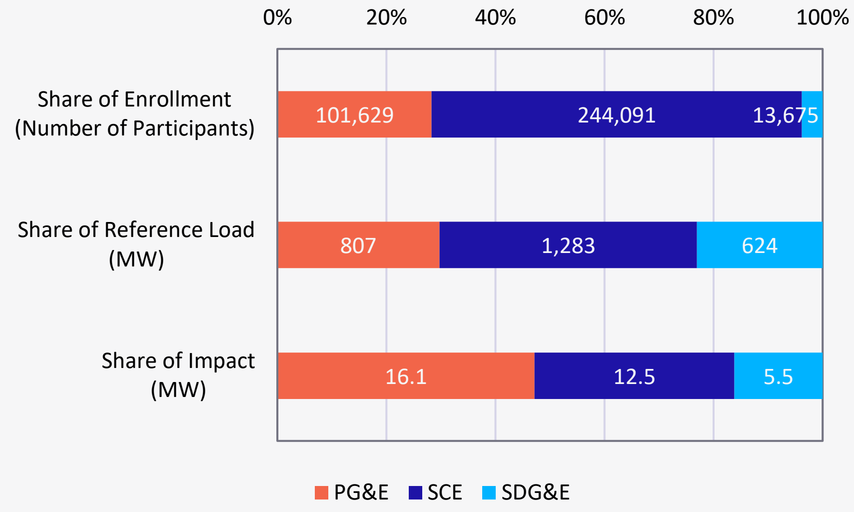

Impacts by Size

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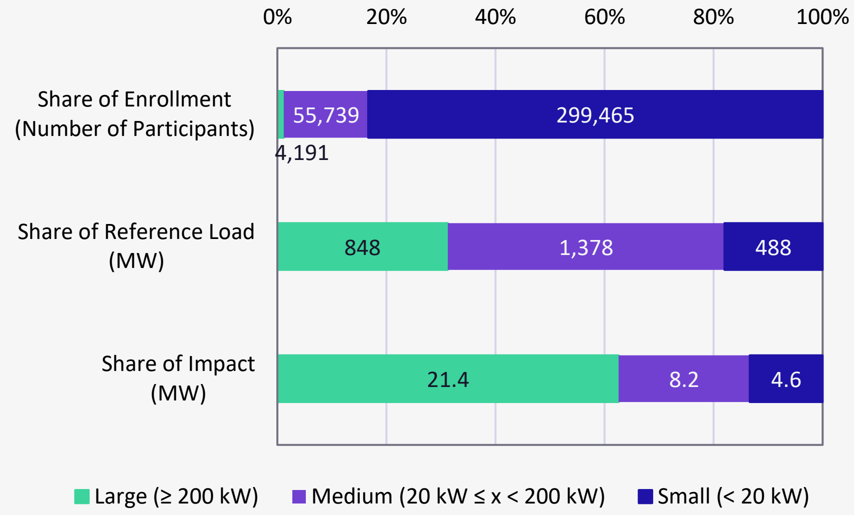

Key Findings

Top Takeaways

- COVID impact on C&I – lower average reference loads
  - Forecast reference loads to slowly increase as restrictions are lifted.
- Weekend events
  - More challenging to model/estimate.
  - Can deliver impacts, but less than weekdays.
  - Not specifically addressed in LI Protocols.
- SCE’s second year of event window switch delivered better results overall
  - Assumptions used in PG&E’s forecast that reflects event window switch in 2021.

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Thank You.

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SCE Residential Default TOU 2020 Load Impact Evaluation

DRMEC Workshop on the Utilities' 2021 Annual Load Impact Protocol Reports

Prepared by:
Eric Bell
Aimee Savage
Dan Lesperance

April 29 & 30, 2021

Nexant
Reimagine tomorrow.

Agenda

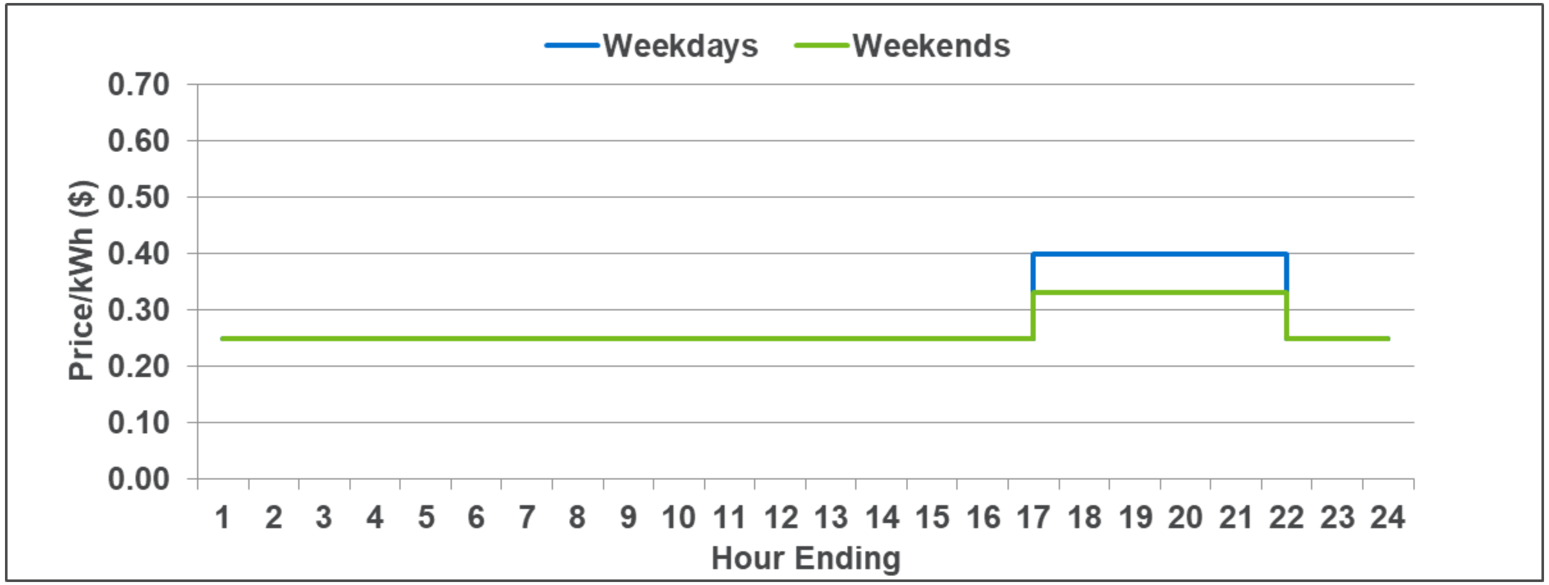
- Background
- Ex Post Methodological Overview
- Program Year 2020 Ex Post Load Impacts
- Ex Ante Methodological Overview
- Ex Ante Load Impacts

Pilot Introduction

- Southern California Edison Company's residential default time-of-use pricing pilot launched in Spring 2018
- The pilot tested two TOU rate options
  - 200,000 customers assigned to Rate 4
  - 200,000 customers assigned to Rate 5
  - 200,000 customers retained as a control
- The ex post findings in this presentation cover the winter period from October 2019 through May 2020 and the summer period from June through September 2020 for the pilot population

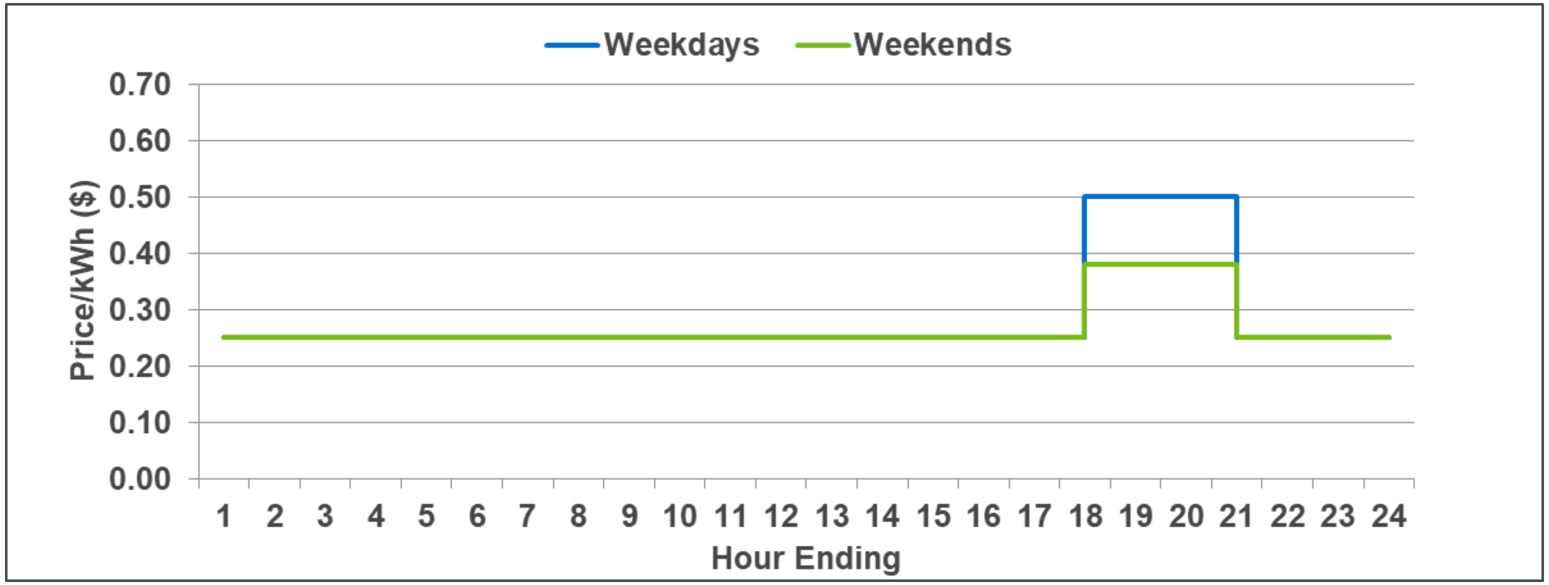
Rate 4 Description (June – September)

- Peak period is weekdays from 4-9 PM and the peak price is 40¢/kWh
- The mid-peak price on summer weekends from 4-9 PM is 33¢/kWh
  - All other hours are 25¢/kWh
- Customers receive a baseline credit of 7¢/kWh up to their monthly baseline allocation



Rate 5 Description (June – September)

- Peak period is weekdays from 5-8 PM and the peak price is 50¢/kWh
- The mid-peak price on summer weekends from 5-8 PM is 38¢/kWh
  - All other hours are 25¢/kWh.
- Customers receive a baseline credit of 7¢/kWh up to their monthly baseline allocation

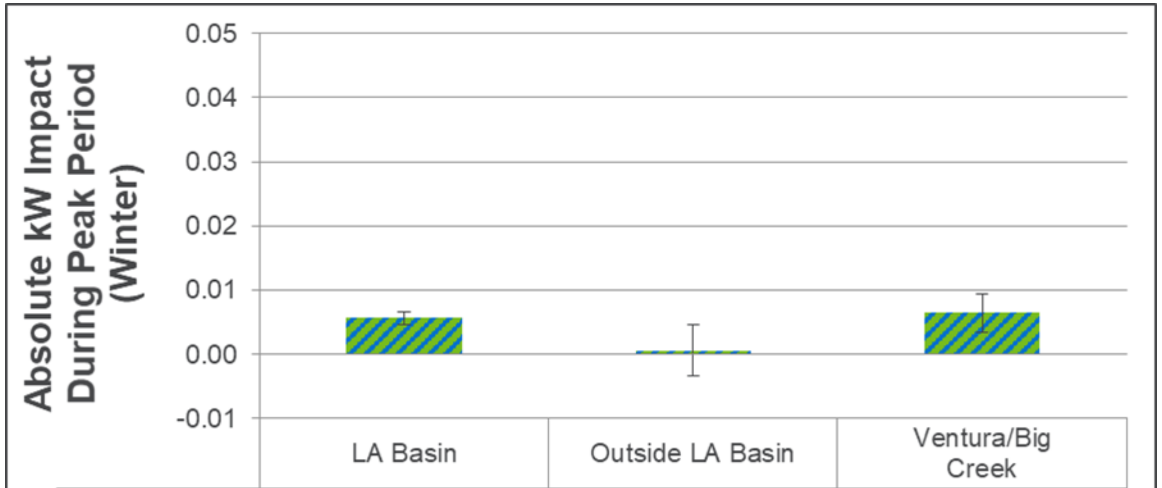


Randomized Encouragement Design

- Fixed effects, difference-in-differences (DiD) model analyzed as a randomized encouragement design (RED)
  - RED allows for differing opt-out rates in the treatment versus control group (as the control group was unaware of the pilot and could not opt out)
- Data for customers who dropped out of the pilot is maintained in the evaluation to estimate the “intention-to-treat” impact, which is then divided by 1 minus the opt-out rate (e.g., if the opt-out rate is 2%, the ITT is scaled up by dividing it by 0.98) to determine the impact for those who stay on the rate
  - Customers who dropped out due to account closures were removed from both the treatment and control groups in the month of the account closure and for all months thereafter

Rate 4 Winter 2019/2020 Average Weekday

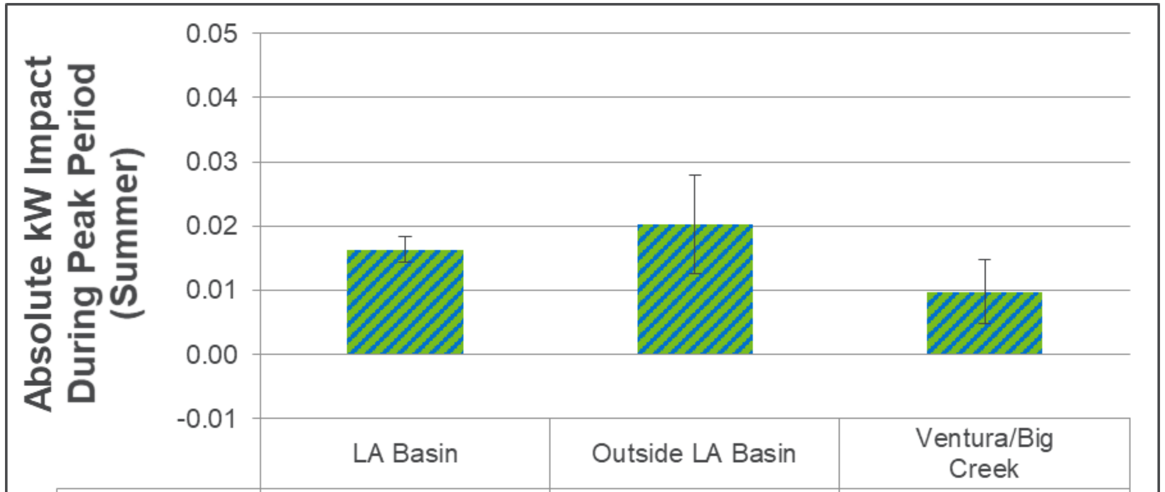
- In the winter months, customers on Rate 4 had impacts of 0.006 kW or 0.6%
  - This is equal to 0.8 MW among ~140k customers active in winter 2019/2020
- Rate 4 peak period impacts were statistically significant in in the LA Basin and Ventura/Big Creek LCAs
  - Peak period impacts in the Outside LA Basin LCA were not statistically significant
- LA Basin and Ventura/Big Creek have similar absolute (0.006 kW and 0.007 kW, respectively) and identical percent impacts (0.7%) during winter average weekday peak periods



	LA Basin	Outside LA Basin	Ventura/Big Creek
Percent Impact	0.7%	0.1%	0.7%
Absolute Impact	0.006	0.001	0.007

Rate 4 Summer 2020 Average Weekday

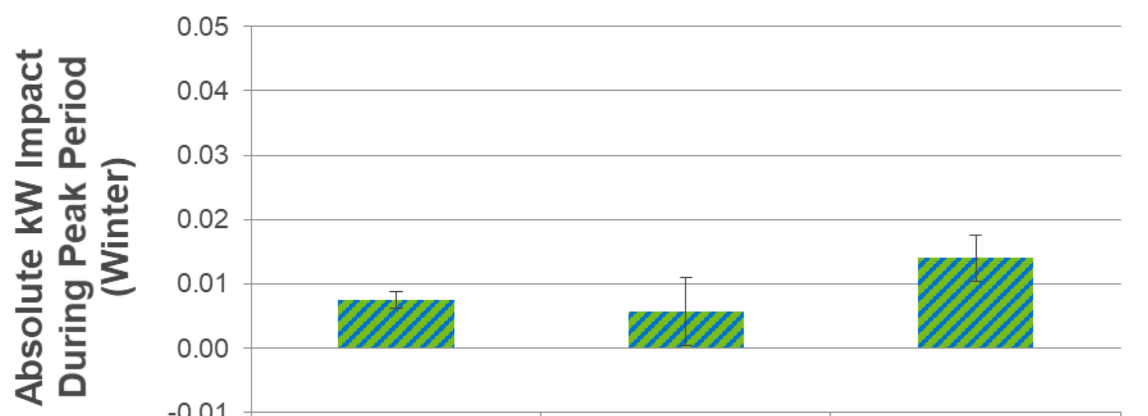
- During the summer months, customers on Rate 4 had impacts of 0.016 kW or 1.1%
  - This is equal to 1.9 MW among ~120k customers active in summer 2020
- Rate 4 impacts were statistically significant in all three LCAs
  - LA Basin and Outside LA Basin have the same percent impacts during summer average weekday peak periods. Ventura has a lower impact than the other two LCAs
  - Although the estimated absolute impacts vary, the difference between the LCAs is not statistically significant



	LA Basin	Outside LA Basin	Ventura/Big Creek
Percent Impact	1.2%	1.2%	0.7%
Absolute Impact	0.016	0.020	0.010

Rate 5 Winter 2019/2020 Average Weekday

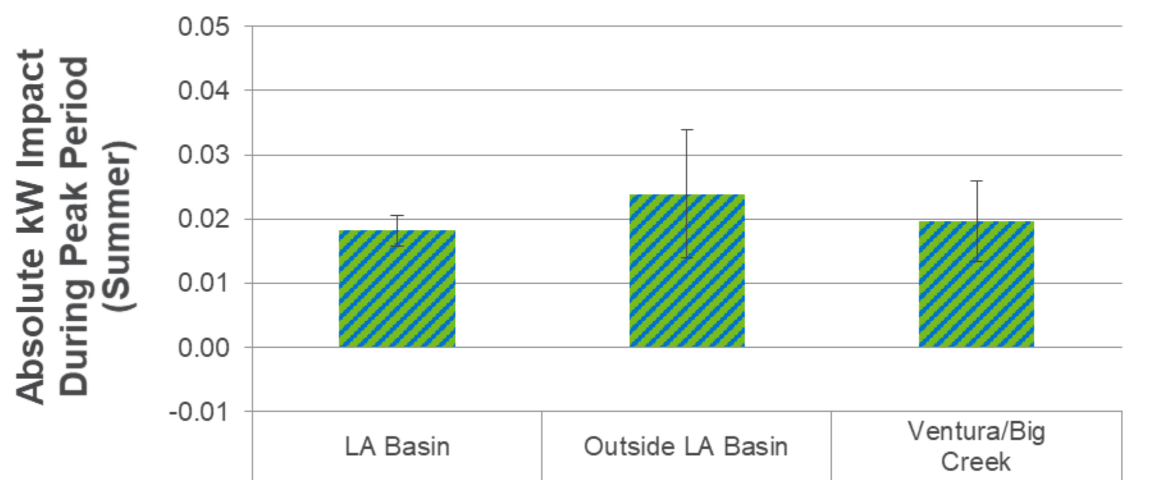
- Overall, customers on Rate 5 had impacts of 0.008 kW or 0.9%
  - This is equal to 1.1 MW among ~140k customers active in winter 2019/2020
- The Ventura/ Big Creek LCA had the largest percent impacts at 1.4%, however the difference in impacts between the Outside LA Basin and Ventura/Big Creek LCAs is not statistically significant
- Winter peak period impacts were equal to 0.9% or 0.007 kW in the LA Basin LCA



	LA Basin	Outside LA Basin	Ventura/Big Creek
Percent Impact	0.9%	0.6%	1.4%
Absolute Impact	0.007	0.006	0.014

Rate 5 Summer 2020 Average Weekday

- Overall, customers on Rate 5 had winter impacts of 0.019 kW or 1.3%
  - This is equal to 2.3 MW among ~120k customers active in summer 2020
- Percent load impacts were similar across all three LCAs (1.3%)
  - Outside LA Basin had the highest absolute impact of 0.024 kW
  - The difference in absolute impact between the LCAs was not statistically significant



	LA Basin	Outside LA Basin	Ventura/Big Creek
Percent Impact	1.3%	1.3%	1.3%
Absolute Impact	0.018	0.024	0.020

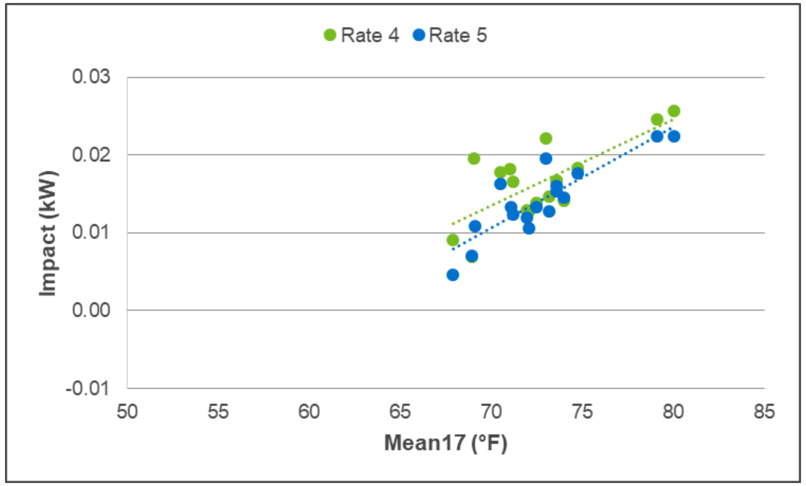
Modeling the relationship between load impacts and weather

- Ex post load impacts from March 2018 through September 2020 were estimated at the weekly level
  - The ex post load impacts that are in the evaluation report were estimated at the monthly and seasonal level
  - Estimating impacts at the weekly level provides more data points and weather variability for estimating the ex ante load impact regression model
- Nexant tested 20 models to estimate the relationship between load impacts, weather conditions, and COVID-19 effects
  - Used out-of-sample testing to compare models
  - Models that predicted best across segments, rates, and calendar months were chosen
  - A similar approach was used to model reference loads (what customers would use in the absence of TOU)

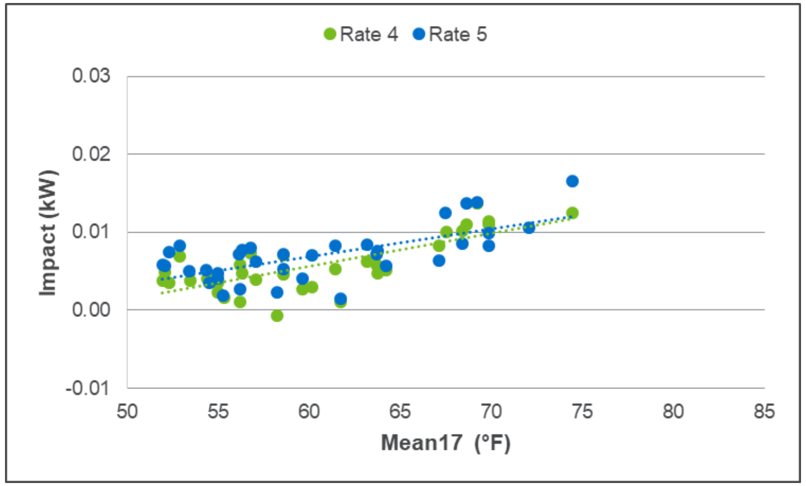
Forecasting ex ante load impacts

- The ex ante model has four independent variables:
  - **Mean17**: Average temperature from 12 AM to 5 PM
  - **Mean17^2**: Average temperature from 12 AM to 5 PM, squared
  - **Month indicator**: Equals 0 if the weekly observation is not in the indicated month, 1 if the week is in the indicated month
  - **COVID-19 indicator**: equals 0 for all weeks through February 2020, and equals 1 for all weeks from March 2020 through September 2020
- Warmer temperatures are expected to lead to larger impacts
  - In the summer months, 1-in-10 weather is warmer than 1-in-2 weather
  - In some winter months, 1-in-2 weather is warmer than 1-in-10 weather
- Nexant estimated the models separately for each hour (1-24), season (summer, winter), LCA (LA Basin, Outside LA Basin, Ventura/Big Creek), forecast year (2021 through 2031), and rate (Rate 4, Rate 5)

Summer



Winter



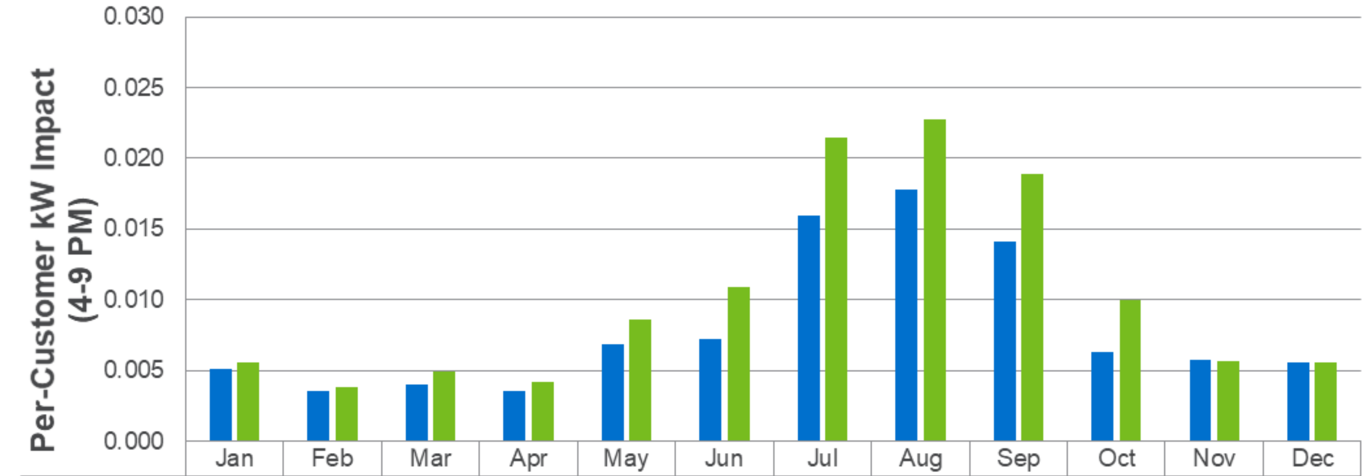
Forecasting ex ante load impacts

- The COVID-19 pandemic is expected to have a continued effect on residential customer demand and peak period impacts
- To estimate the effects of COVID-19 on customer impacts (and demand), a COVID-19 indicator was included in the model
  - The COVID-19 effect indicator is equal to 1 starting in March 2020 (during the ex post period), before declining annually to zero in 2028 through 2031
  - This indicator is being used by all DR evaluators

Year	Covid Indicator
2020 (Mar-Dec, ex post)	1.00
2021	0.50
2022	0.25
2023	0.13
2024	0.06
2025	0.03
2026	0.02
2027	0.01
2028	0.00
2029	0.00
2030	0.00
2031	0.00

Rate 4 Ex Ante Impacts per Customer (2021)

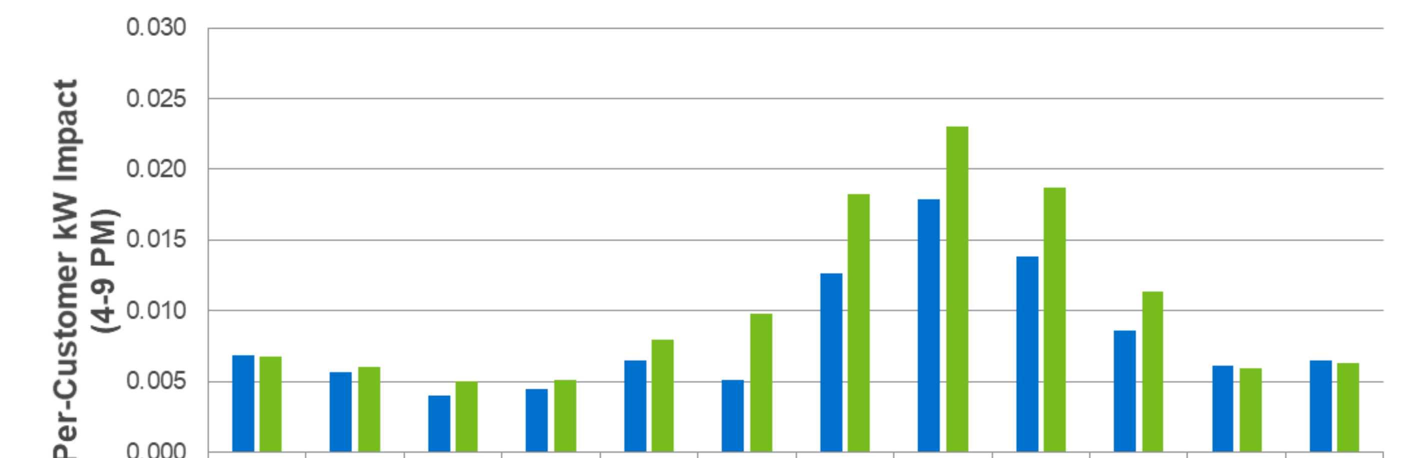
- Impacts are presented for the Resource Adequacy (RA) window, which is 4:00 to 9:00 PM
  - This is the same as the peak period for Rate 4, but the Rate 5 peak period is 5:00 to 8:00 PM
- Per-customer impacts are expected to reach about 0.02 kW in July, August, and September under 1-in-10 weather conditions
- Impacts are expected to be smallest under 1-in-2 conditions in February, March, and April
- 2021 estimates include a COVID-19 indicator of 0.5, estimating that COVID-19 will have half the impact on electric demand and load impacts than it did from March to December 2020



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SCE 1-in-2	0.005	0.004	0.004	0.004	0.007	0.007	0.016	0.018	0.014	0.006	0.006	0.006
SCE 1-in-10	0.006	0.004	0.005	0.004	0.009	0.011	0.021	0.023	0.019	0.010	0.006	0.006

Rate 5 Ex Ante Impacts per Customer (2021)

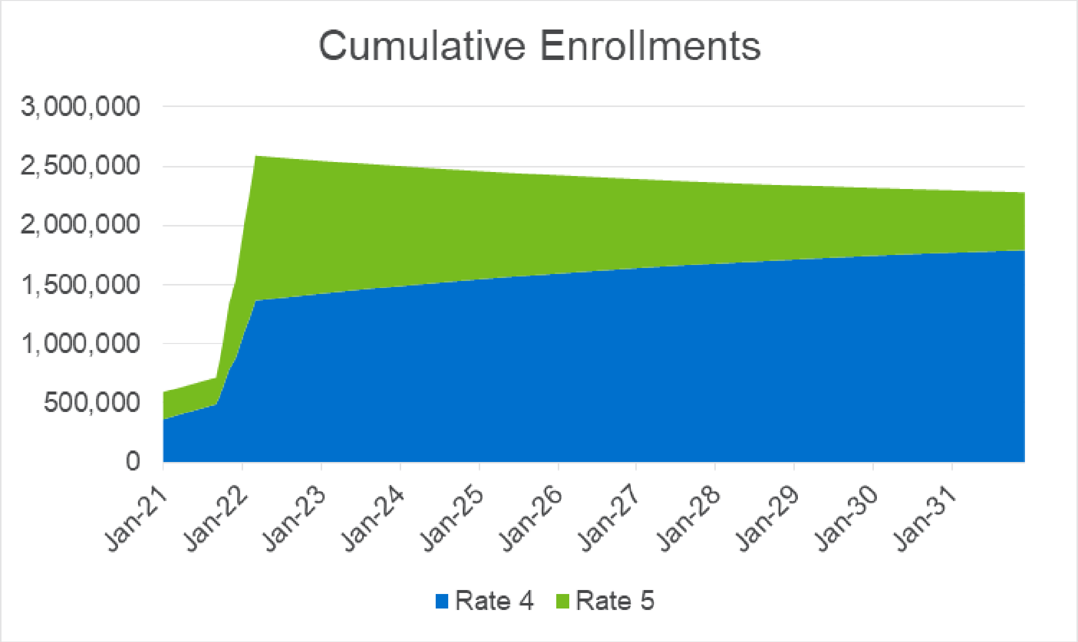
- Impacts are presented for the RA window, but the peak period for Rate 5 is 5 to 8 PM
- Per-customer impacts for the 1-in-10 weather year are expected to reach above 0.02 kW in July, with August and September impacts expected to be just below 0.02 kW.
- Impacts are expected to be smallest under 1-in-2 conditions in the shoulder months of March and April
- Expected Rate 5 load impacts are slightly higher than Rate 4 in winter months in both weather scenarios
  - Impacts are about even in summer months, with expected July impacts being higher for Rate 4 than Rate 5



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SCE 1-in-2	0.007	0.006	0.004	0.004	0.006	0.005	0.013	0.018	0.014	0.009	0.006	0.006
SCE 1-in-10	0.007	0.006	0.005	0.005	0.008	0.010	0.018	0.023	0.019	0.011	0.006	0.006

Total Aggregate MW Impacts (Rate 4 + Rate 5)

- For both Rate 4 and Rate 5, there will be several waves of new enrollments in 2021 through 2022 (about 1.8 million after adjusting for pre-enrollment opt outs)
  - Approximately 20k Rate 4 and 1.6k Rate 5 customers will join the rates each month as customers turn on new accounts with SCE
  - Enrollment attrition of 1% for each month was assumed from January 2021 through December 2031
- Aggregate impacts sharply increase in 2022, following large waves of new default enrollments onto Rate 4 and Rate 5 in late 2021 and early 2022 (totaling to around 1.8 million new customers)
- Although per-customer impacts increase from 2021 through 2031 due to the diminishing effects of the pandemic, aggregate summer impacts begin to decrease starting in 2023 as customers leave Rate 5 through natural attrition



Forecast Year	Aggregate MW Load Reduction							
	1-in-2				1-in-10			
	Jun	Jul	Aug	Sep	Jun	Jul	Aug	Sep
2021	4.4	10.2	12.5	10.0	7.1	14.0	16.0	13.5
2022	20.3	41.3	50.0	40.1	31.0	55.6	62.9	52.5
2023	22.0	42.7	50.9	41.2	32.4	56.7	63.6	53.4
2024	22.8	43.3	51.1	41.5	32.9	57.0	63.5	53.5
2025	22.9	43.2	50.6	41.3	32.9	56.7	62.8	53.0
2026	22.8	42.8	49.9	40.8	32.5	56.2	62.0	52.4
2027	22.7	42.6	49.4	40.3	32.2	55.7	61.3	51.8
2028	22.6	42.3	48.9	40.0	32.0	55.3	60.6	51.3
2029	22.4	42.0	48.3	39.5	31.6	54.8	59.9	50.7
2030	22.2	41.7	47.8	39.1	31.3	54.4	59.3	50.2
2031	22.1	41.4	47.3	38.7	31.0	54.0	58.8	49.8

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PG&E Residential Default Time-of-Use Rates

Dan Hansen
Mike Clark
Christensen Associates Energy Consulting

April 2021

Presentation Outline

- Introduction
- PG&E Time-of-Use (TOU) Rate Overview
- Basis for the ex-ante forecast
- 2021 through 2024 forecast

PG&E TOU Rate Overview

- PG&E's Default TOU rate is E-TOU-C
  - Peak period: 4:00 p.m. to 9:00 p.m. on all days
  - Off-peak period: all other hours
  - Includes a baseline credit
- PG&E's E-TOU-C enrollment forecast reflects waves of TOU defaults occurring from April 2021 through March 2022
- Optional TOU rates are also available
  - E-TOU-D removes the baseline credit (therefore appealing to higher-use customers and has a shorter peak period (5 to 8 p.m.) that applies only on non-holiday weekdays
  - EV2-A is a whole-house TOU rate available to customers who charge an EV at home. It has three pricing periods. We discuss this rate in a separate presentation.
  - EV-B is an EV-only rate for separately metered EV charging that contains three pricing periods

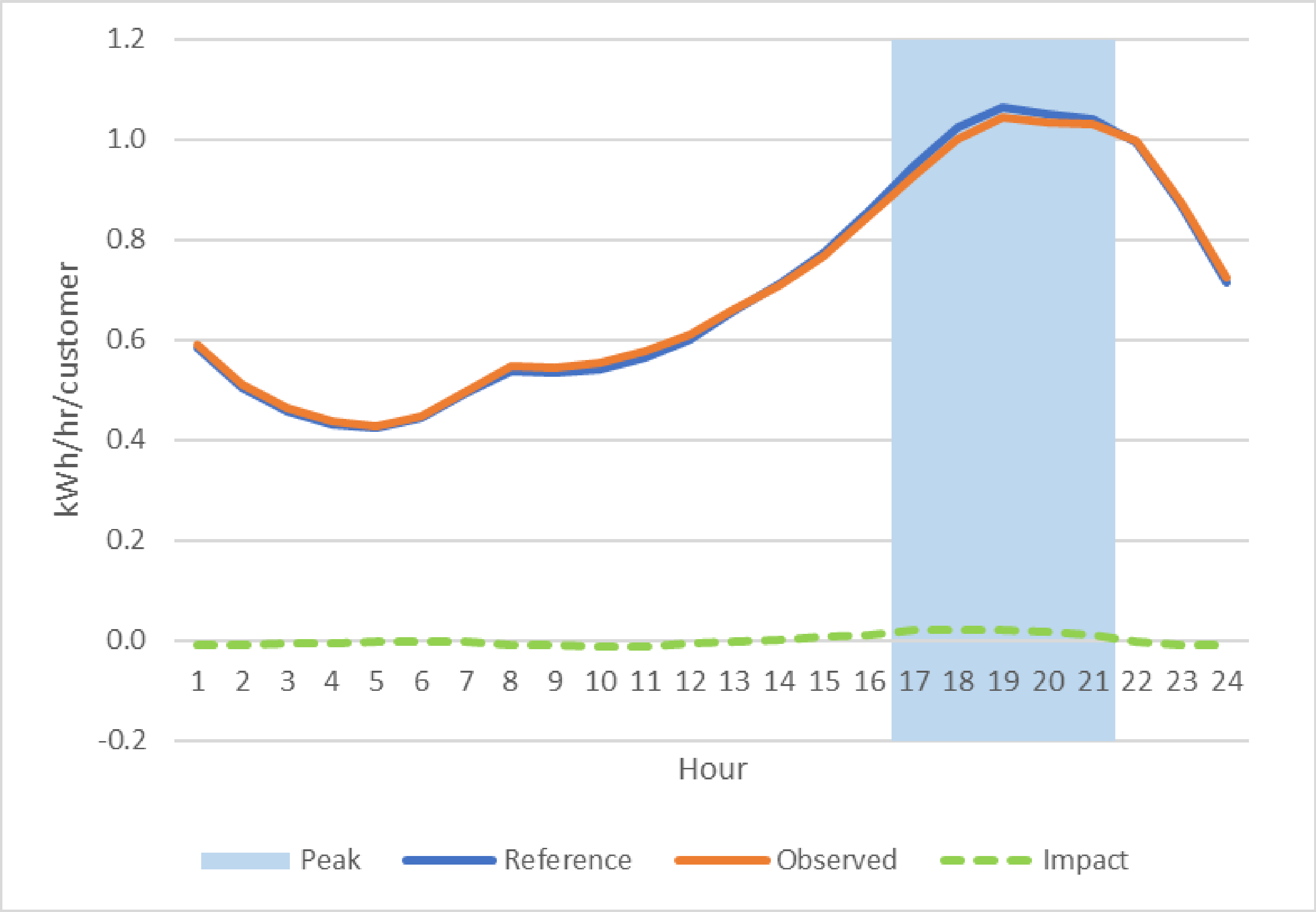
Default TOU Ex-Ante Forecast Basis

- The PY2020 ex-post evaluation for E-TOU-C was limited to a relatively small number of voluntary adopters
- We would not expect these customers to be representative of the broader default TOU population
- The Default TOU Pilot from June 2018 through May 2019 contains the best available information about Default TOU impacts
- Pilot used segments defined by climate region and CARE status
- Default findings were adapted (essentially re-weighted) to conform to the LCA-level forecast required for this ex-ante forecast

Default TOU Ex-Ante Forecast:
COVID Discussion

- The Default TOU Pilot that serves as the basis of the forecast uses pre-pandemic data
- We did not adjust the forecast to account for pandemic effects
  - While it is clear that Shelter-in-Place (SIP) orders led to an increase in residential usage, the SIP effect on *load impacts* is less clear
  - If *percentage* impacts are assumed to be constant across SIP and no-SIP scenarios (and everything in between), the expected effect of SIP on load impacts is minimal (one thousandth of a kWh/hr/customer or less)

Summer Ex-Ante Forecast:
Aug. 2021 PG&E 1-in-2 Peak Day



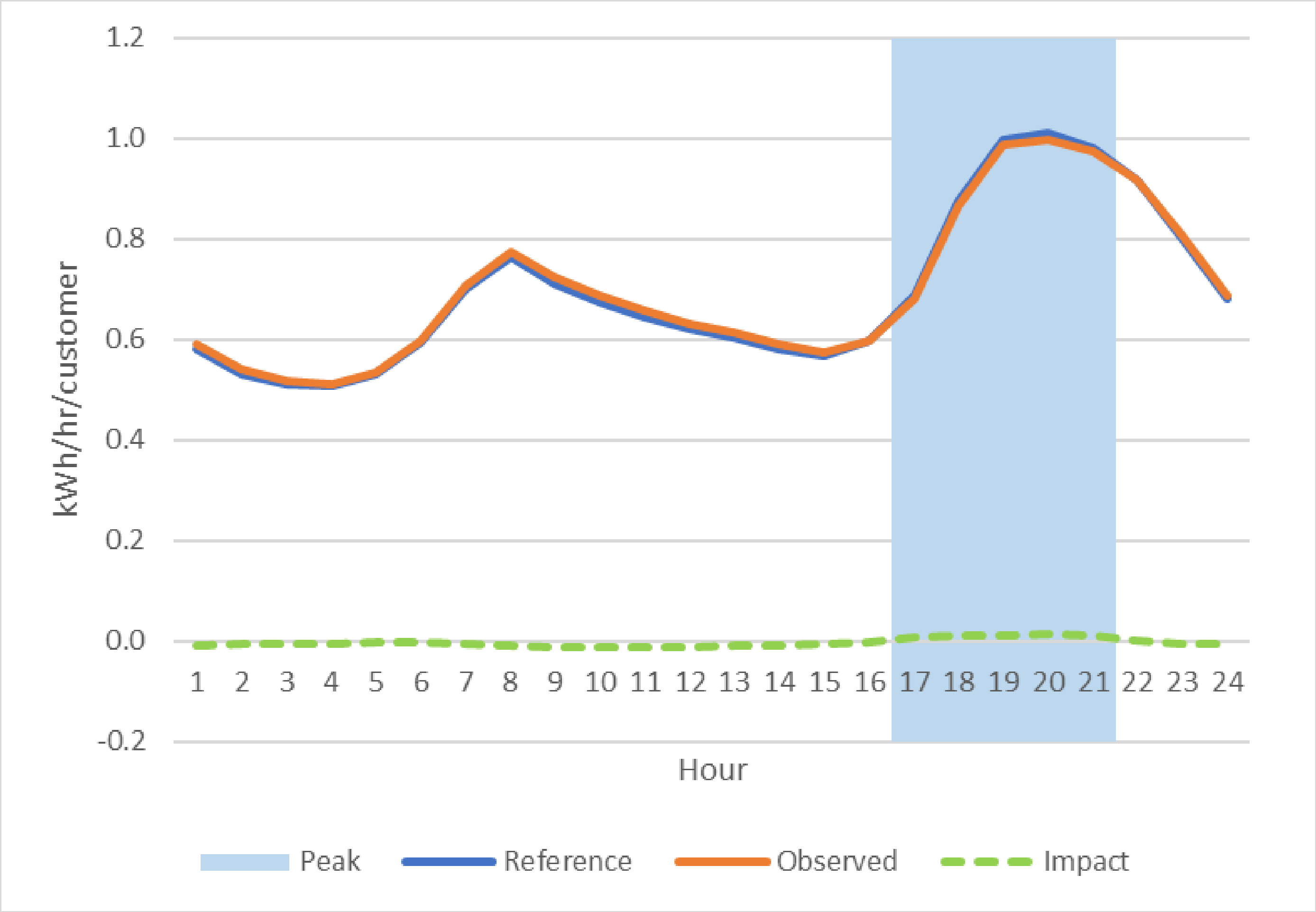
Summer Ex-Ante Forecast:

Aug. PG&E 1-in-2 Peak Days, 2021-24

Year	# Enrolled (millions)	Aggregate (MWh/hr)		Per Customer (kWh/hr)		% Impact
		Reference Load	Load Impact	Reference Load	Load Impact	
2021	1.15	1,174	20.9	1.025	0.018	1.8%
2022	2.58	3,287	66.9	1.272	0.026	2.0%
2023	2.62	3,337	67.9	1.272	0.026	2.0%
2024	2.64	3,359	68.4	1.272	0.026	2.0%

The values represent the average during the Resource Adequacy Window (4 to 9 p.m.)

Winter Ex-Ante Forecast:
Jan. 2022 PG&E 1-in-2 Peak Day



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Winter Ex-Ante Forecast:

Jan. PG&E 1-in-2 Peak Days, 2021-24

Year	# Enrolled (millions)	Aggregate (MWh/hr)		Per Customer (kWh/hr)		% Impact
		Reference Load	Load Impact	Reference Load	Load Impact	
2021	0	n/a	n/a	n/a	n/a	n/a
2022	1.96	1,785	20.3	0.911	0.010	1.1%
2023	2.61	2,454	28.1	0.941	0.011	1.1%
2024	2.62	2,471	28.3	0.941	0.011	1.1%

The values represent the average during the Resource Adequacy Window (4 to 9 p.m.)

Summary

- PG&E's Default TOU ex-ante forecast is based on the full-year pilot evaluation
- We expect summer impacts to be higher than winter impacts
- While the per-customer impacts may be regarded as modest, the expected scale of participation leads to potentially significant aggregate load impacts
- The default process that occurs during 2021 and 2022 will provide information to allow us to update these estimates in the PY2021 evaluation

Questions?

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Residential Customer Response to Electric Vehicle Time-of-Use Rates

Mike Clark
Dan Hansen
Christensen Associates Energy Consulting

April 2021

Presentation Outline

- Introduction
- SDG&E and PG&E Electric Vehicle Time-of-Use (EV-TOU) Rate Overview
- Challenge in estimating EV customer demand response
- Method of identifying EV adopters
- Estimated Ex-Post EV-TOU load impacts
- Estimated Ex-Ante EV-TOU load impacts

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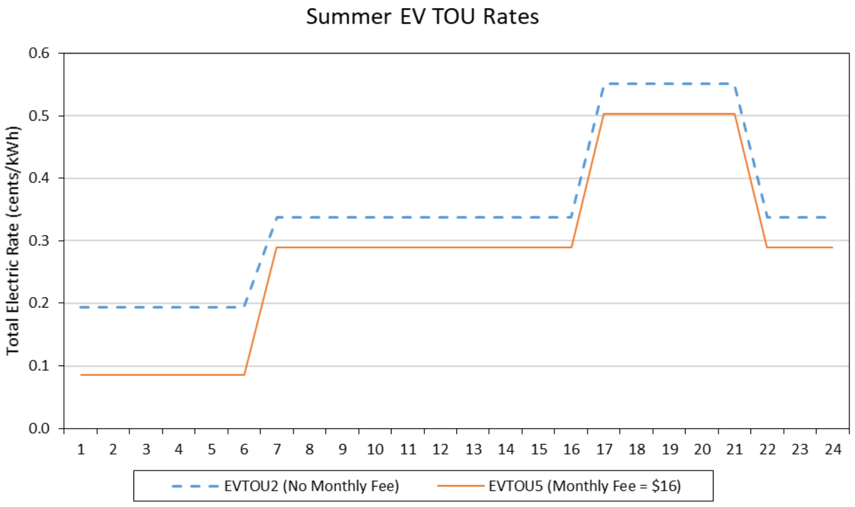
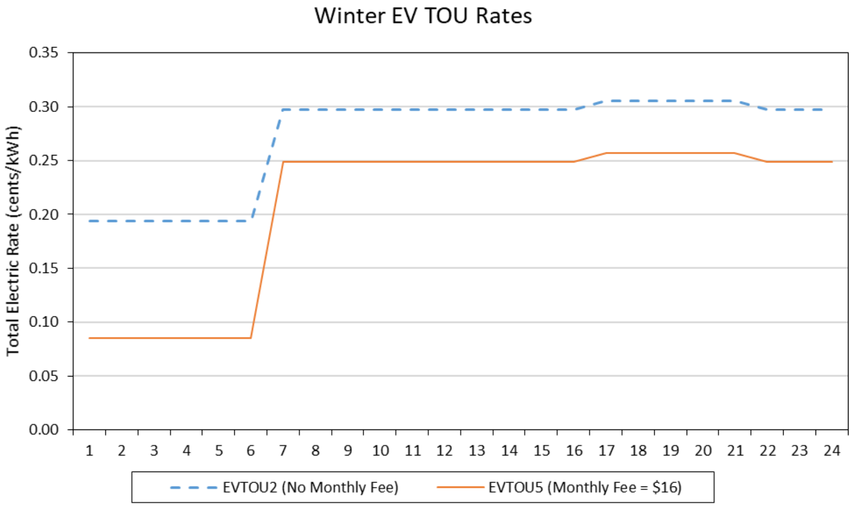
SDG&E EV-TOU-2 and EV-TOU-5

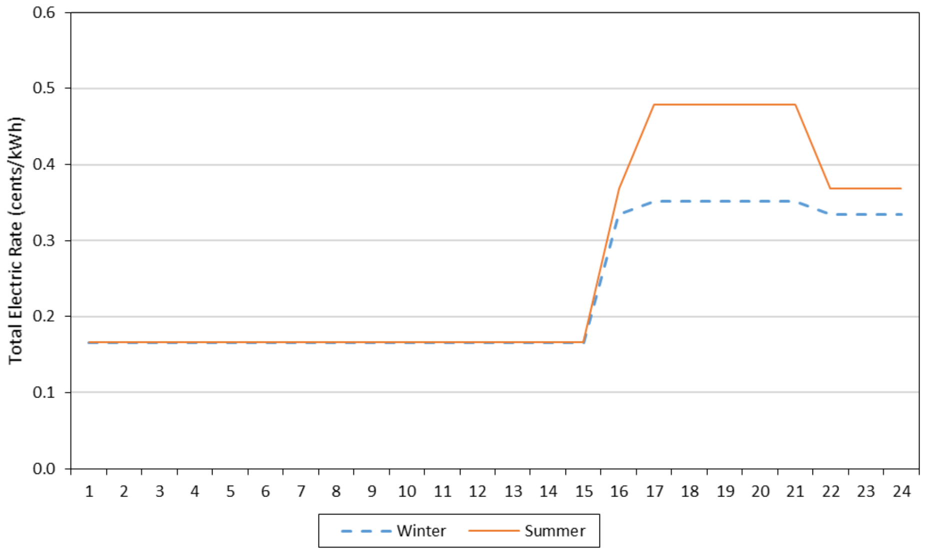
- <u>Rate Differences</u>
  - EV-TOU-5 rates are lower, e.g.,
    - ~10 cents/kWh lower during super off-peak period
    - ~5 cents/kWh lower during other periods
  - EVTOU-5 includes a $16/month Basic Service FEE
- <u>Same pricing periods, both are whole-house rates</u>
  - On-peak period from 4 to 9 p.m. every day
  - Super off-peak period:
    - midnight to 6 a.m. on non-holiday weekdays;
    - 10 a.m. to 2 p.m. in March and April non-holiday weekdays;
    - midnight to 2 p.m. on weekends and holidays
- Rates are seasonally differentiated
- EV-TOU-5 opened later (in 2018)





PG&E EV2-A

- Only available to customers who charge an electric vehicle.
- Does not contain a tiered structure
- Whole house rate
- Pricing Period on all days:
  - On-peak period from 4 to 9 p.m.
  - Partial-peak period 3-4 p.m., 9 p.m. – midnight
  - Off-peak period midnight – 3 p.m.



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EV Customer Response to TOU Pricing

Two types of demand response may be of interest:

1. Do EV customers change their usage behavior when they change from the standard tiered rate to EV rate (e.g., SDG&E's EV-TOU-2 or EV-TOU-5, PG&E EV2-A)?
   - Do customers shift usage from high- to low-cost pricing periods?
   - Does the absence of tiered rates affect the overall usage level?

2. Do EV customers change their usage behavior when they change from SDG&E's EV-TOU-2 to EV-TOU-5?
   - Will EV-TOU-5 customers tend to shift charging into the Super Off-Peak period?
   - Will lower overall rates affect total usage?

Challenge of Estimating EV Customer Response to TOU Pricing

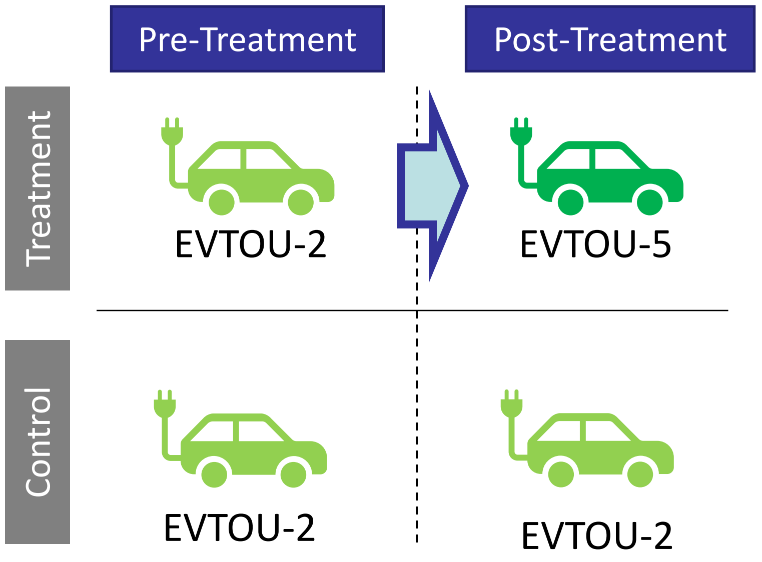
- Want to estimate how an EV customer changes behavior in response to a rate change
- This can be done via a differences-in-differences analysis, for example:
  - Obtain data before and after EV customers switched from the tiered rate to a TOU rate (the "treatment" customers)
  - Match the treatment customers to "control-group" EV customers, who remain on the tiered rate for the entire analysis period
  - Estimate EV-TOU load impacts as the difference between treatment and control-group customer loads during the treatment period, adjusting for the difference in their loads during the pre-treatment period

Problem: Utility does not know when a customer acquires and begins charging an EV

EV-TOU Analysis Issues Summary

- Time period definitions
  - Pre-treatment year = October 2018 through September 2019
  - Treatment year = October 2019 through September 2020
- SDG&E EV-TOU-2 to EV-TOU-5 switchers
  - Treatment group consists of customers who switched from EV-TOU-2 to EV-TOU-5 during the treatment year, who were enrolled in EV-TOU-2 during the entire pre-treatment year
  - Control group consists of customers who were enrolled in EV-TOU-2 for the entire pre-treatment and treatment years
  - Load impacts are estimated using difference-in-differences:

$$\text{Load Impact} = (T_1 - C_1) - (T_0 - C_0)$$



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EV-TOU Analysis Issues Summary (2)

- Tiered rate to EV-TOU
  (e.g., SDG&E EV-TOU-2 or EV-TOU-5, PG&E EV2-A)
  - Separate analyses for each rate
  - Treatment group consists of customers who switched from the tiered rate to EV-TOU rate during the treatment year, who were enrolled in the tiered rate during the entire pre-treatment year
  - There is no control group, as we don't have information about EV ownership for customers on non-EV rates
  - Load impacts are estimated as before vs. after within treatment group, controlling for weather effects

    Load Impact = $(T_1 - T_0)$

Hard part: All treatment customer must have an EV during the entire analysis period

How to Identify EV Ownership?

- As mentioned earlier, SDG&E and PG&E does not comprehensively track EV ownership of its customers
- However, SDG&E and PG&E restricts its EV-TOU rates to customers with a plug-in EV
- So we know that a customer served on SDG&E's EV-TOU-2 or EV-TOU-5, or PG&E's EV2-A had an EV during that time, we just need to confirm they had one while they were on the tiered rate during the pre-treatment period
- We do this via statistical tests for a **structural break** in the customer's usage data

Testing for a Structural Break

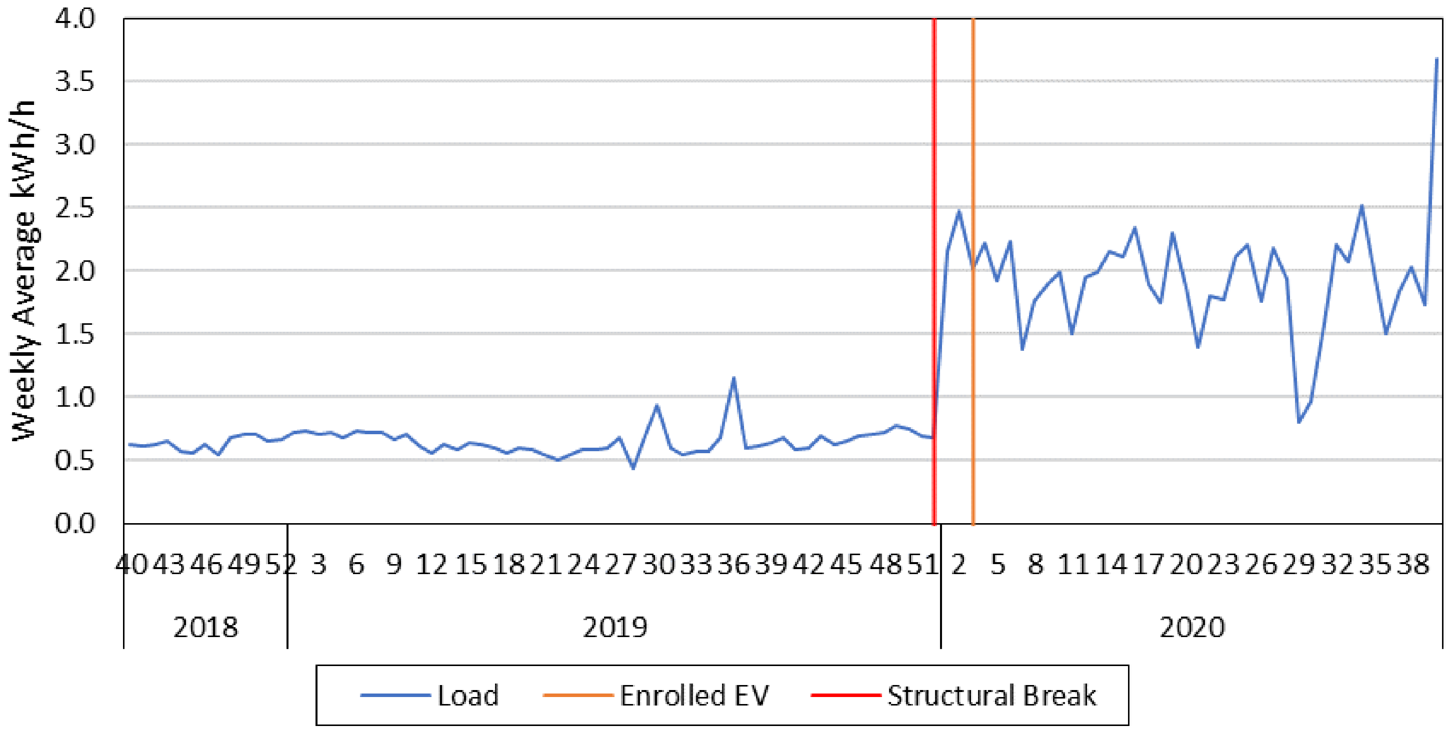
- Develop customer-specific data consisting of weekly total usage
- Estimate customer-specific models of weekly usage as a function of cooling and heating degree days and month indicator variables
- Conduct a Wald test for every possible structural break date (the weeks in the model) using the model's residuals
- That is, the model is trying to find the date where there's the biggest before/after difference in what the model *can't* explain
- Record the date with the most likely structural break (i.e., largest Wald value) and retain the test statistic

Which Customers are Retained for the Analysis?

- The model keeps customers for whom we **cannot** identify a statistically significant structural break in their usage data
- That is, we'd expect an EV adopter to see a significant increase in total usage due to charging
- If that occurs during our sample timeframe, our method should be able to identify a statistically significant structural break in the usage data
- When we can't identify such a break and we know the customer had an EV at some point (because they were on an EV-TOU rate), we infer they had an EV during the entire analysis period

Example Customer, Screened Out Due to EV Adoption

This customer was rejected from the EV-TOU load impact study because the model identifies a statistically significant structural break in their usage data



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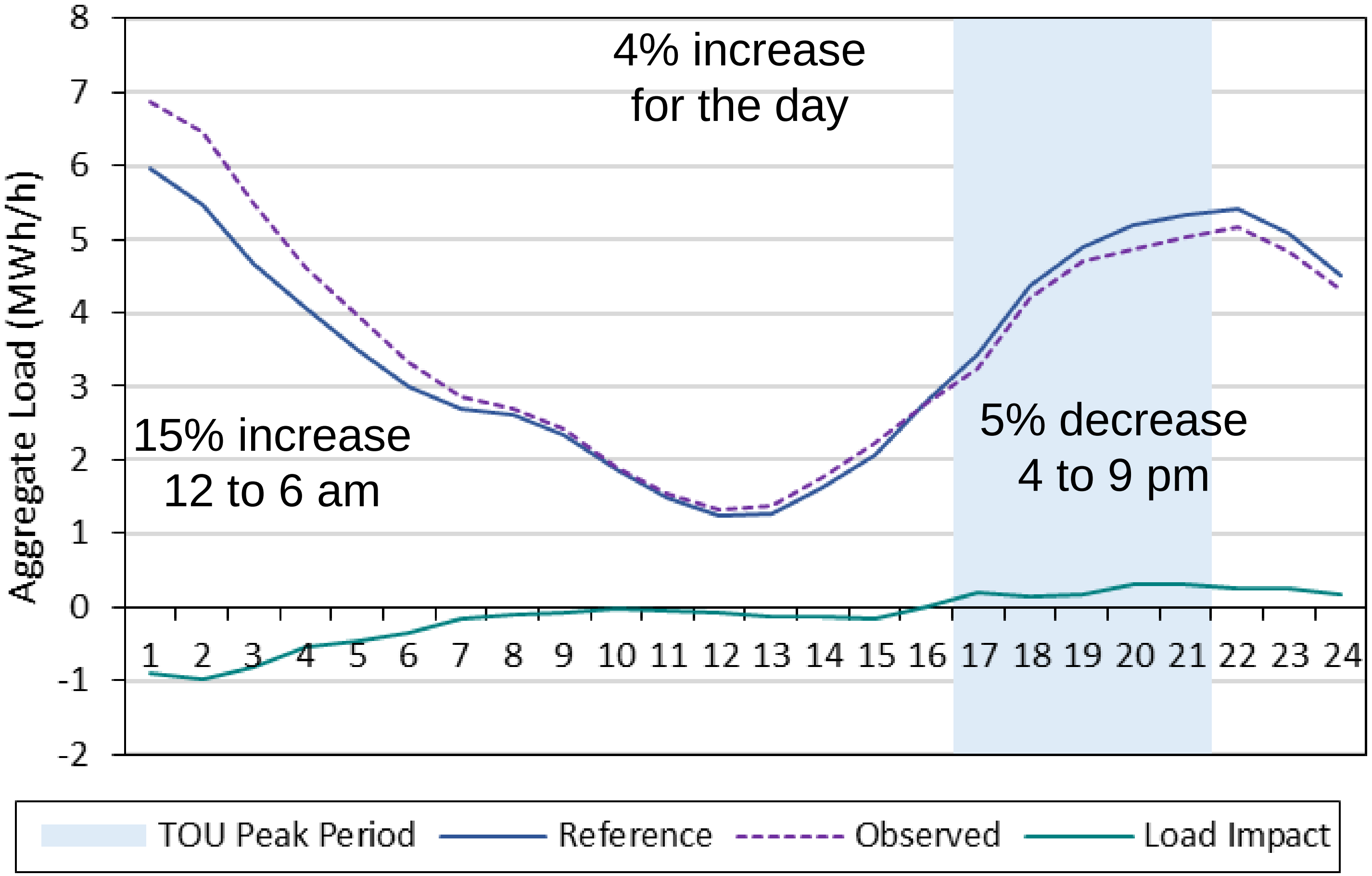
Estimated Ex-Post Load Impacts

SDG&E EV-TOU-2 to EV-TOU-5

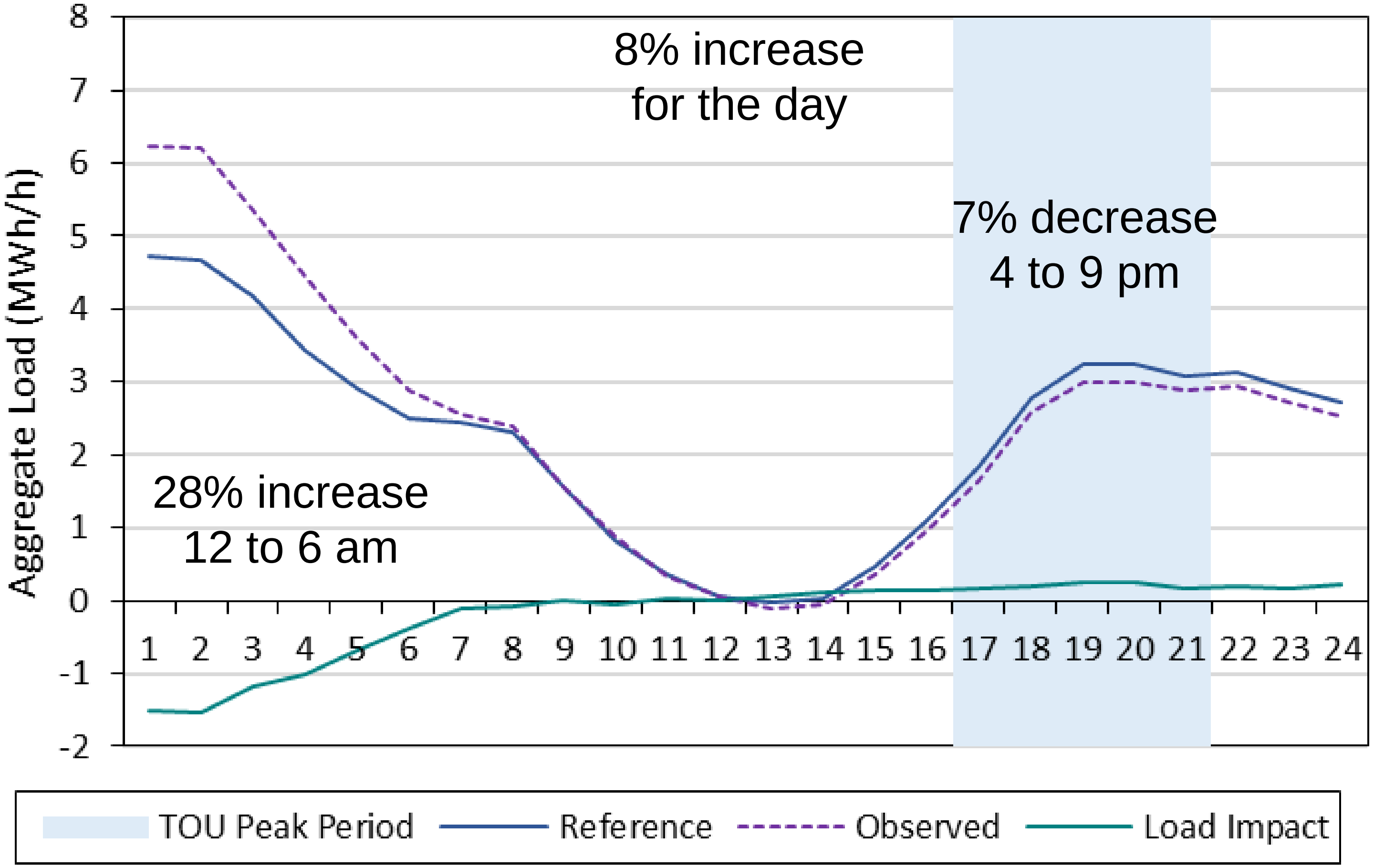
- Recall that EV-TOU-5 has somewhat lower energy rates overall and a much lower rate during the Super Off-Peak period (midnight to 6 a.m.)

- Estimates show that after switching to EV-TOU-5, customers
  - Use much more in the Super Off-Peak period
  - Use somewhat less during the On-Peak period
  - Increase total daily usage

SDG&E EV-TOU-2 to EV-TOU-5: August 2020 Average Weekday



SDG&E EV-TOU-2 to EV-TOU-5: January 2020 Average Weekday

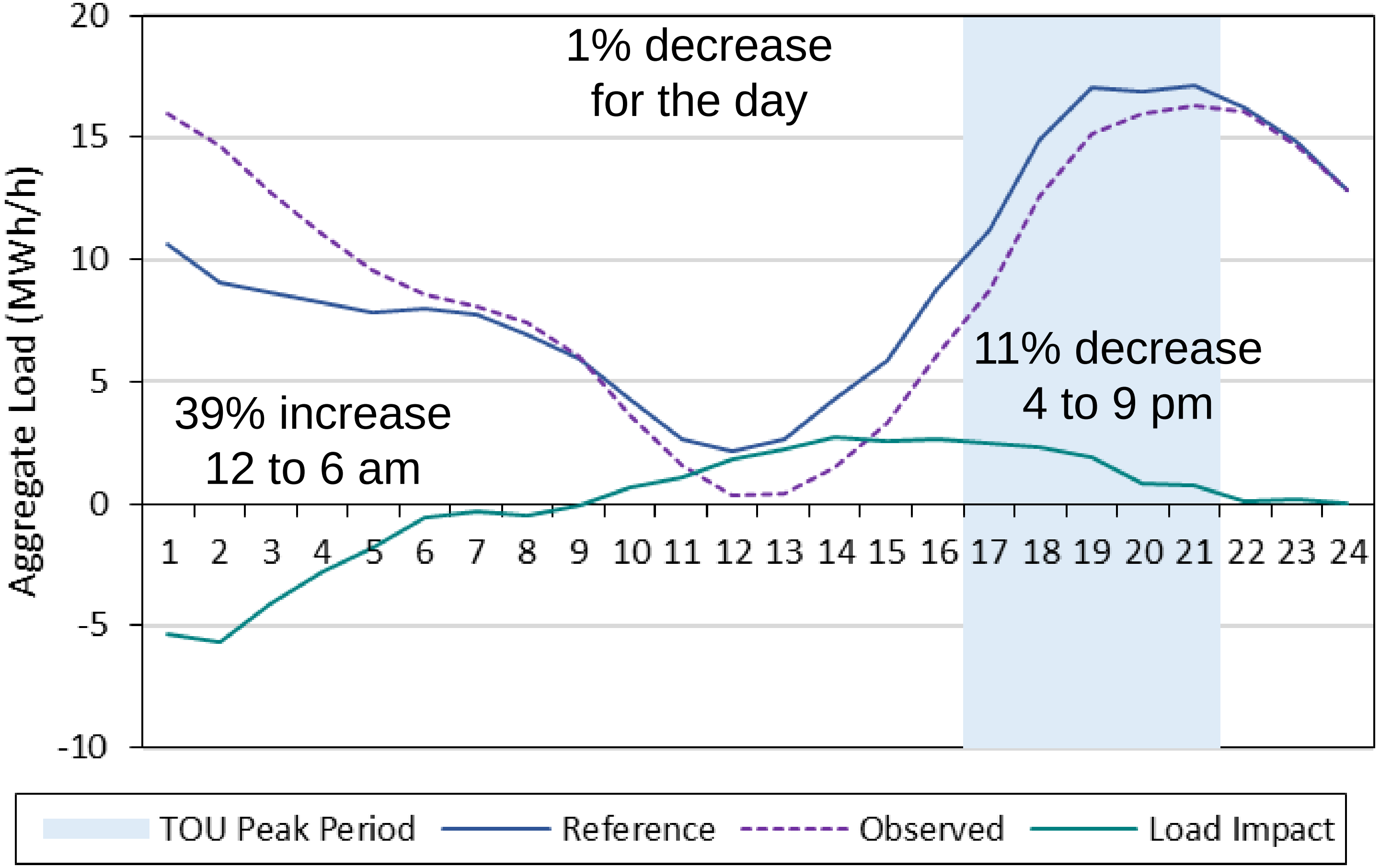


SDG&E Tiered Rate to EV-TOU-2

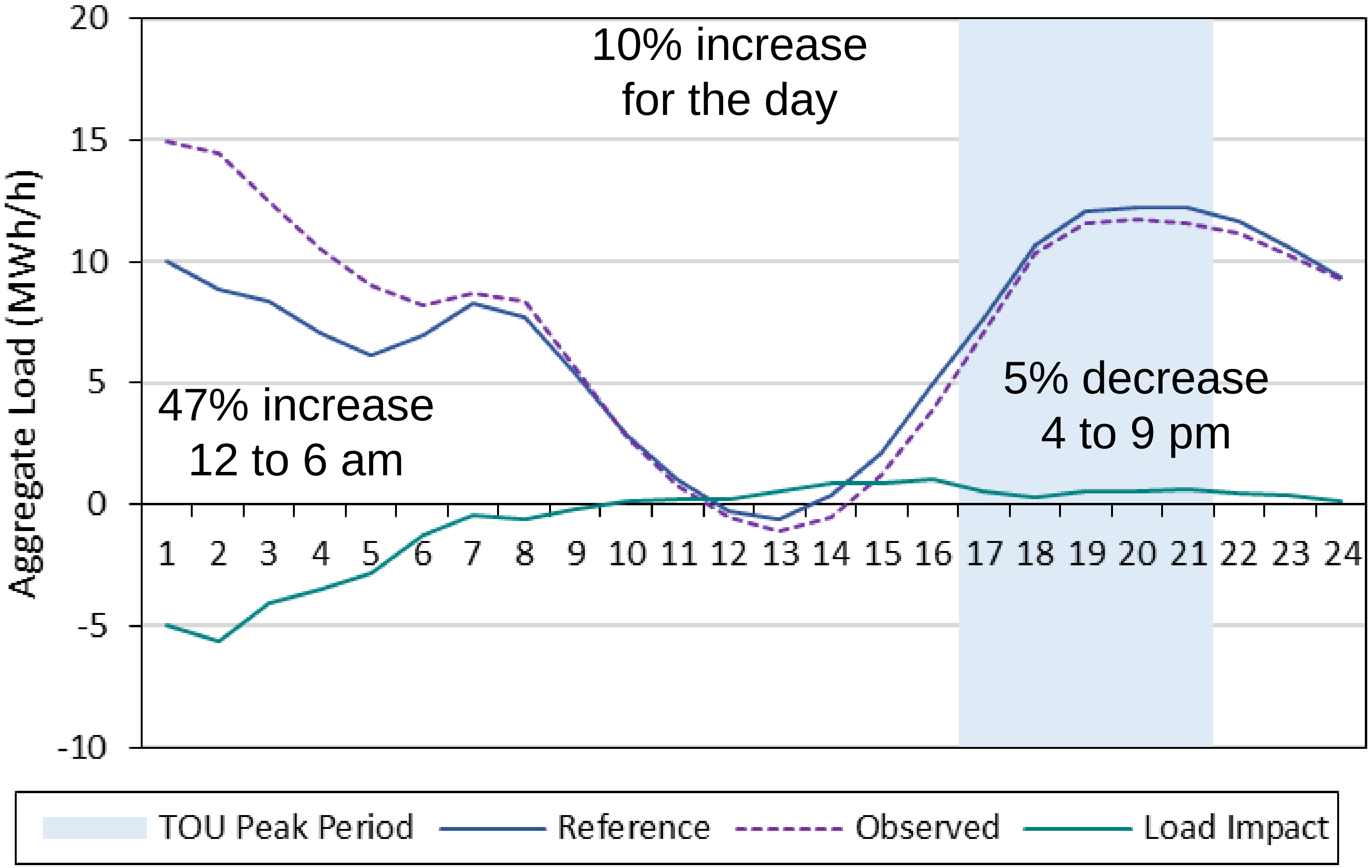
- Relative to the standard tiered rate, EV-TOU-2:
  - Has no tiered component (rate does not vary with total billing-month sales)
  - Has prices that vary by time of day (versus the same all day)

- Estimates show that after switching to EV-TOU-2, customers
  - Use much more in the Super Off-Peak period
  - Use somewhat less during the On-Peak period
  - Display minimal change in total daily usage

SDG&E Tiered Rate to EV-TOU-2: August 2020 Average Weekday



SDG&E Tiered Rate to EV-TOU-2: January 2020 Average Weekday



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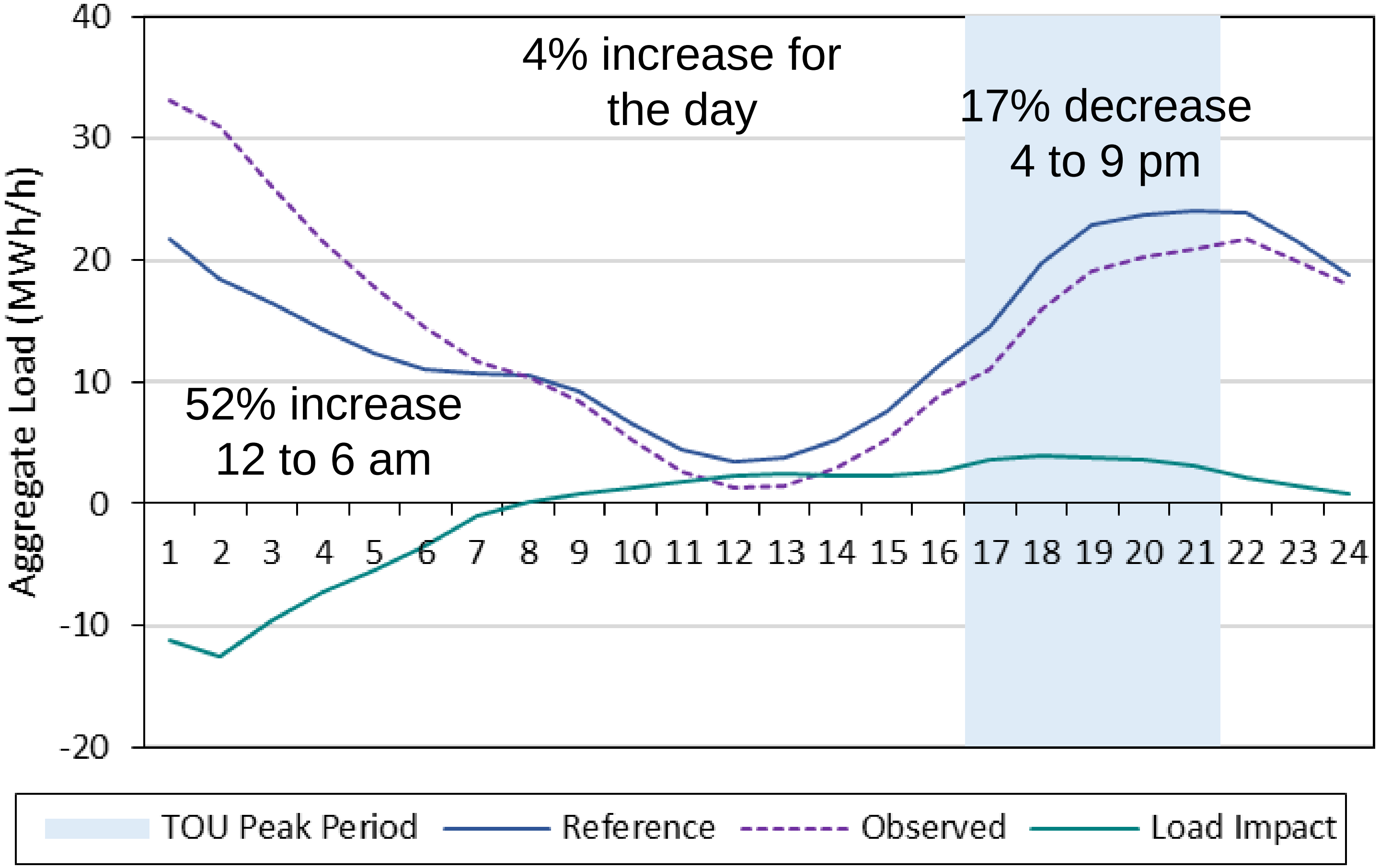
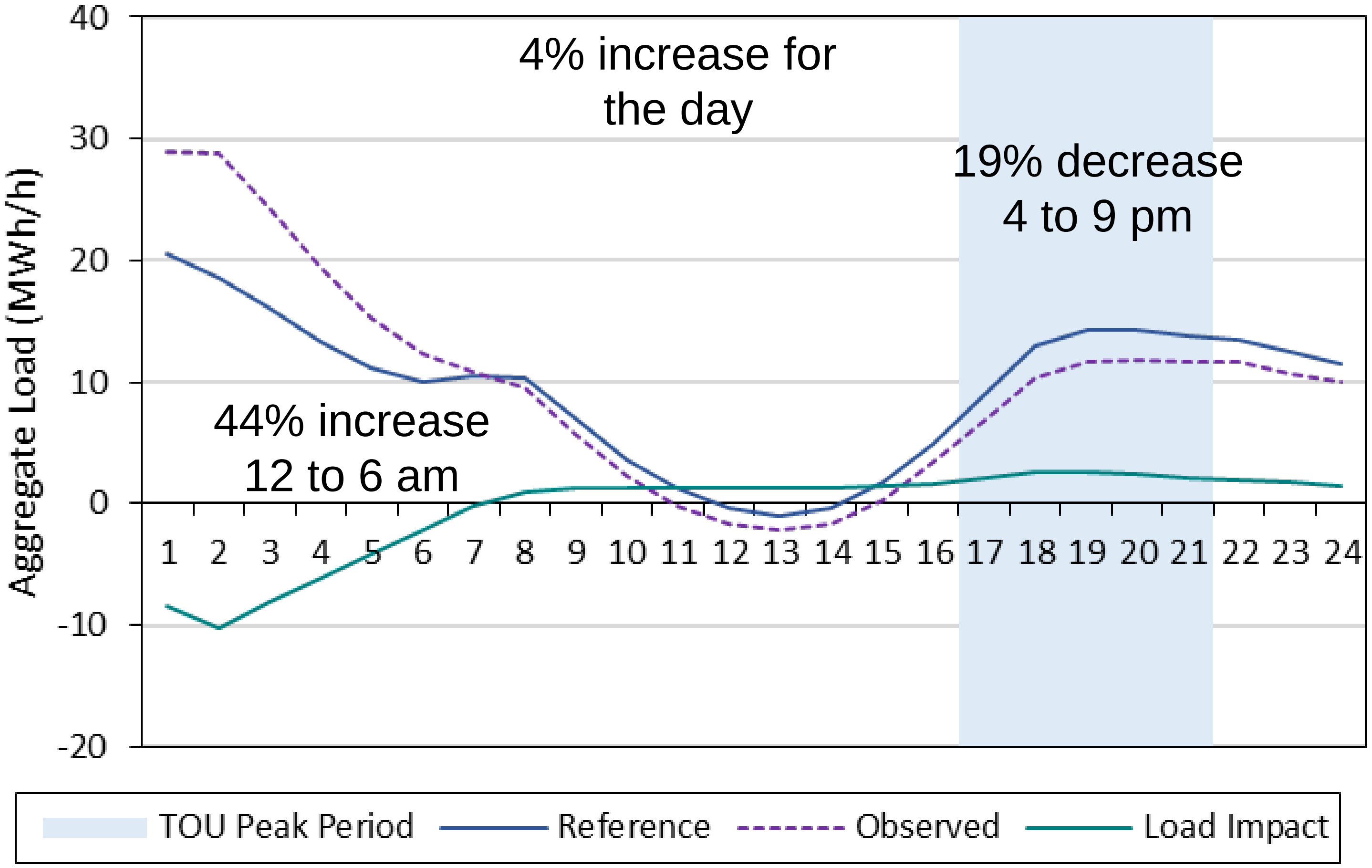
SDG&E Tiered Rate to EV-TOU-5

- Relative to the standard tiered rate, EV-TOU-5:
  - Has no tiered component (rate does not vary with total billing-month sales)
  - Has prices that vary by time of day (versus the same all day)
  - Introduces a monthly Basic Service Fee of $16
  - Reduces energy prices relative to EV-TOU-2 in exchange for Basic Service Fee
- Estimates show that after switching to EV-TOU-5, customers
  - Use much more in the Super Off-Peak period
  - Use less during the On-Peak period
  - Display mixed results regarding the change in total daily usage

SDG&E Tiered Rate to EV-TOU-5: August 2020 Average Weekday



SDG&E Tiered Rate to EV-TOU-5: January 2020 Average Weekday

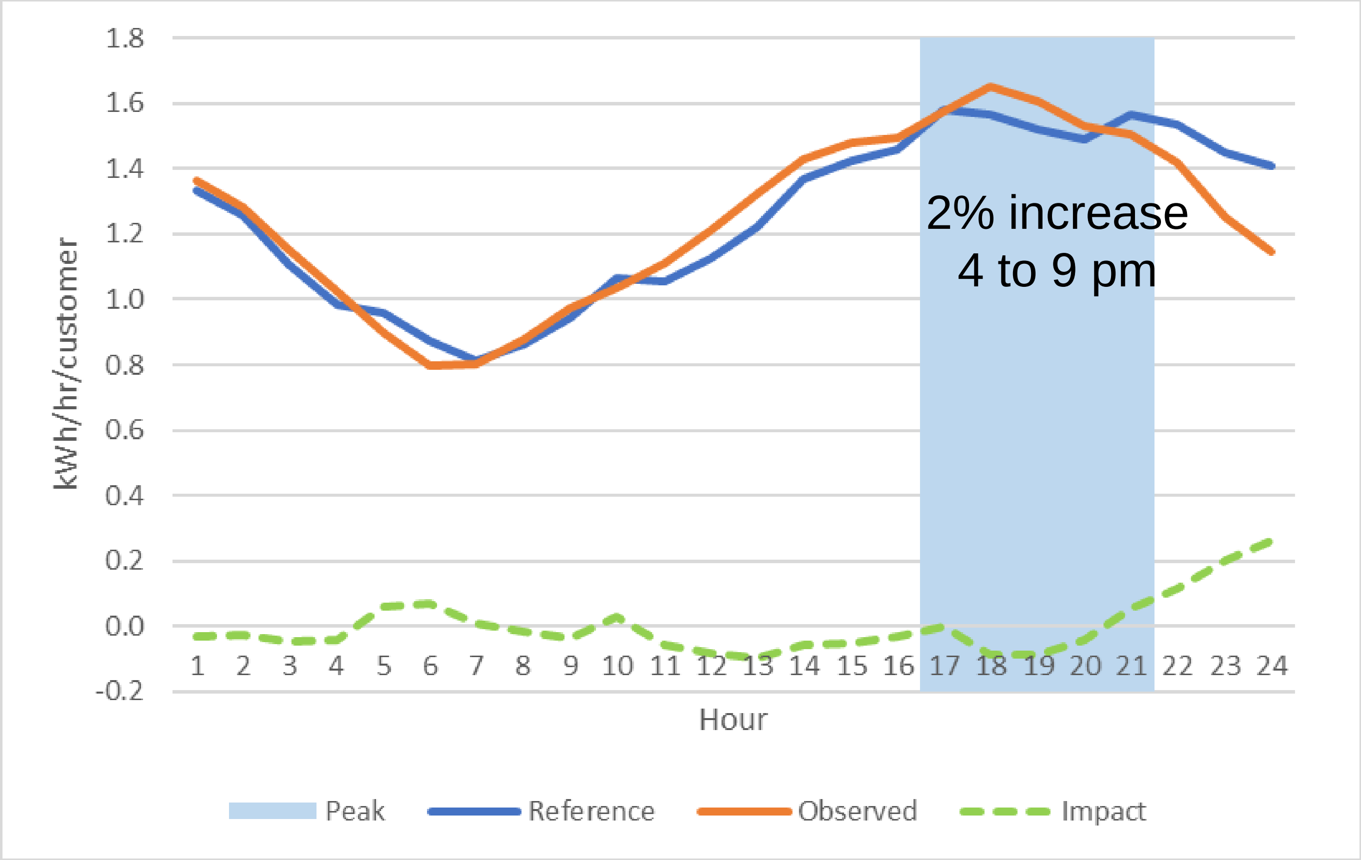


PG&E Tiered Rate to EV2-A

- Relative to the standard tiered rate, EV2-A:
  - Has no tiered component (rate does not vary with total billing-month sales)
  - Has prices that vary by time of day (versus the same all day)

- Estimates show that after switching to EV2-A, customers
  - Use much more in the Off-Peak period during winter months
  - Use less during the On-Peak period during winter months
  - Effects are less pronounced during summer months, potentially as a result of less EV charging due to COVID-19

PG&E Tiered Rate to EV2-A: August 2020 Average Weekday



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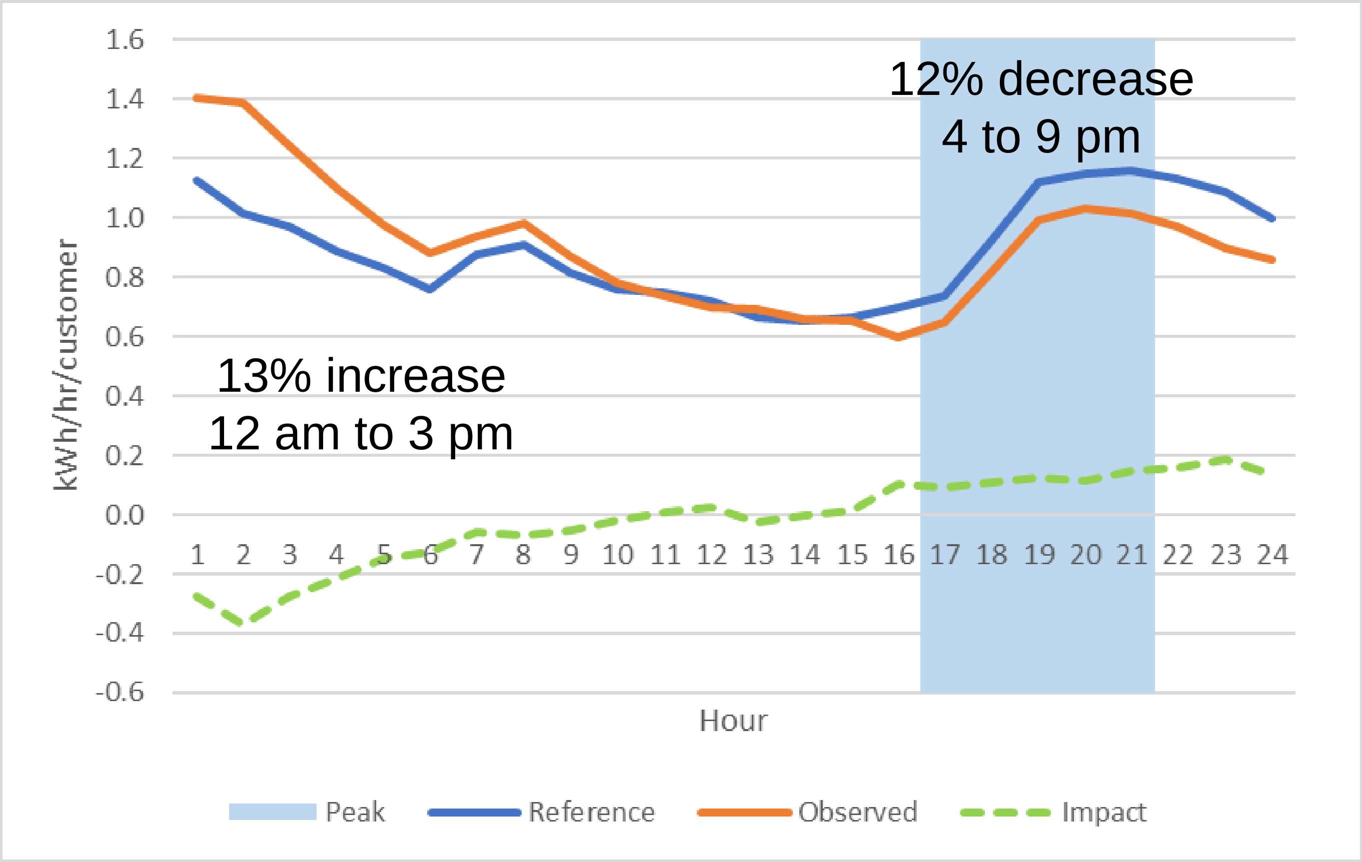
PG&E Tiered Rate to EV2-A: February 2020 Average Weekday



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Comparison Across Rates

- The table below summarizes per-customer reference loads and load impacts by rate and pricing period for 2020
  - Positive load impact = load reduction
  - Negative load impact = load increase

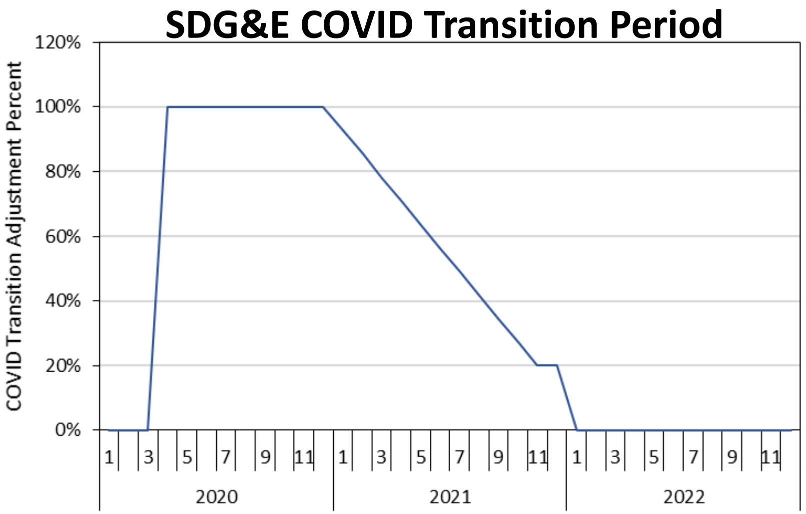
Utility	Group	Month	Enrolled Customers	On-Peak Period			(Super) Off-Peak Period		
				Reference Load (kWh/hr)	Load Impact (kWh/hr)	% Impact	Reference Load (kWh/hr)	Load Impact (kWh/hr)	% Impact
SDG&E	EV-TOU-2 to EV-TOU-5	Aug	2,279	2.04	0.10	5%	1.95	-0.30	-15%
	Tiered to EV-TOU-2		7,719	2.00	0.21	11%	1.13	-0.44	-39%
	Tiered to EV-TOU5		10,867	1.93	0.33	17%	1.45	-0.76	-52%
PG&E	Tiered to EV2-A	Feb	3,956	1.02	0.12	12%	0.83	0.15	-13%
		Aug	7,516	1.54	-0.03	-2%	1.09	-0.02	-2%

Ex-Ante

Ex-Ante Reference Loads

- Reference loads are simulated using the following:
  - Group level regressions (e.g., rate, climate zone, NEM) to obtain effect of weather and time-period indicators on usage
  - *Ex-ante* day types and weather conditions (*e.g.*, August peak month day in a utility-specific 1-in-2 weather year)

- Reference loads are adjusted for COVID
  1. Estimate hourly per-customer COVID effects via regressions
  2. Make assumption regarding COVID transition period
  3. Apply COVID effect to reference loads based on the transition period



Note: 2023-2031 COVID adjustment = 0%

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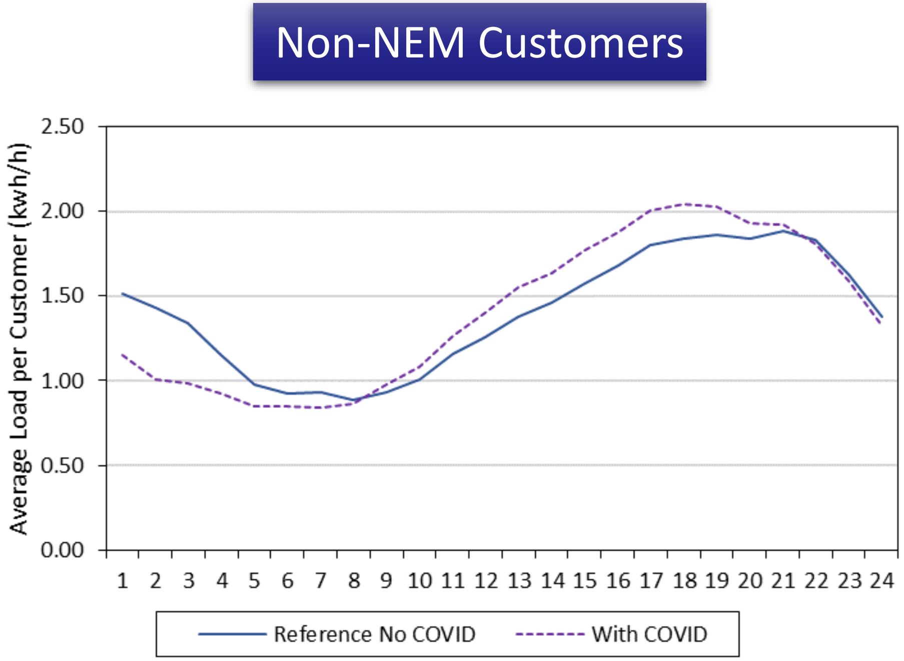
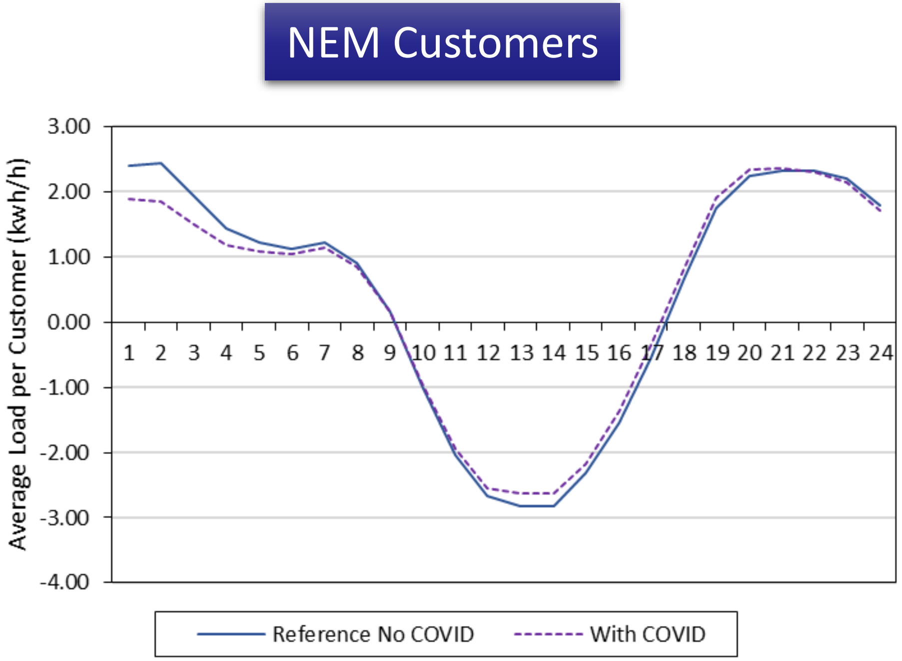
Load Change Due to Covid-19: SDG&E EV-TOU-2





- Load change due to COVID-19 is similar for other EV-TOU rates
- Ex-post percentage load impacts are applied to COVID-19 adjusted ex-ante reference loads

Note: Average August weekday loads shown above

PG&E EV2-A Ex-Ante Forecast:
Aug. PG&E 1-in-2 Peak Days, 2021-24

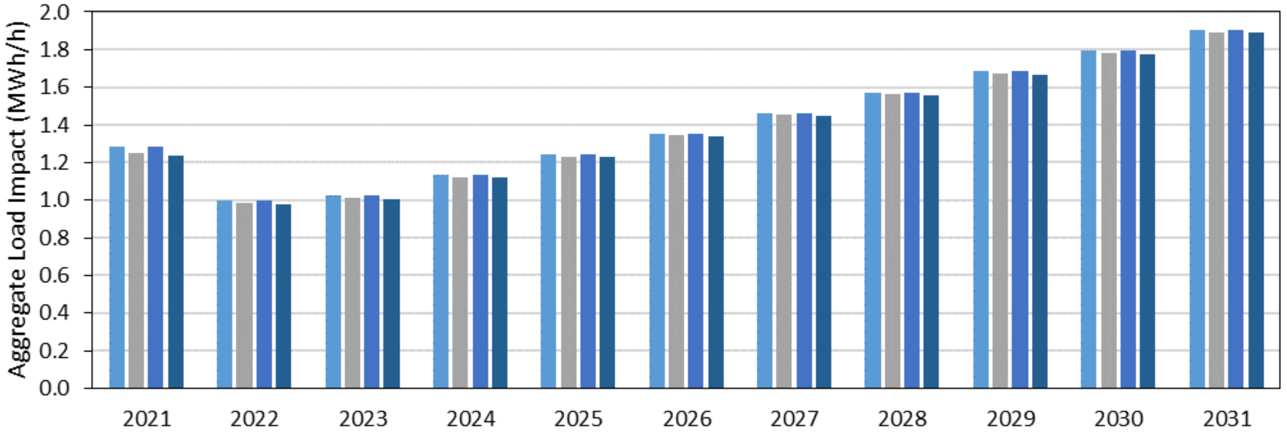
Utility	Rate	Year	# Enrolled (millions)	Aggregate (MWh/hr)		Per Customer (kWh/hr)		% Impact
				Reference Load	Load Impact	Reference Load	Load Impact	
SDG&E	Tiered to EV-TOU-2	2021	6,752	10.8	1.24	1.6	0.18	11.4%
		2022	6,022	8.7	0.98	1.4	0.16	11.2%
		2023	6,233	8.7	1.01	1.4	0.16	11.6%
		2024	6,915	9.6	1.12	1.4	0.16	11.6%
	Tiered to EV-TOU-5	2021	14,468	24.9	4.58	1.7	0.32	18.4%
		2022	18,049	29.6	5.52	1.6	0.31	18.6%
		2023	19,242	31.6	5.88	1.6	0.31	18.6%
		2024	19,242	31.6	5.88	1.6	0.31	18.6%
PG&E	Tiered to EV2-A	2021	7,639	8.8	0.63	1.2	0.09	7.2%
		2022	21,560	25.7	2.53	1.2	0.12	9.9%
		2023	37,112	44.3	4.85	1.2	0.13	11.0%
		2024	55,842	66.6	7.30	1.2	0.13	11.0%

The values represent the average during the Resource Adequacy Window (4 to 9 p.m.)

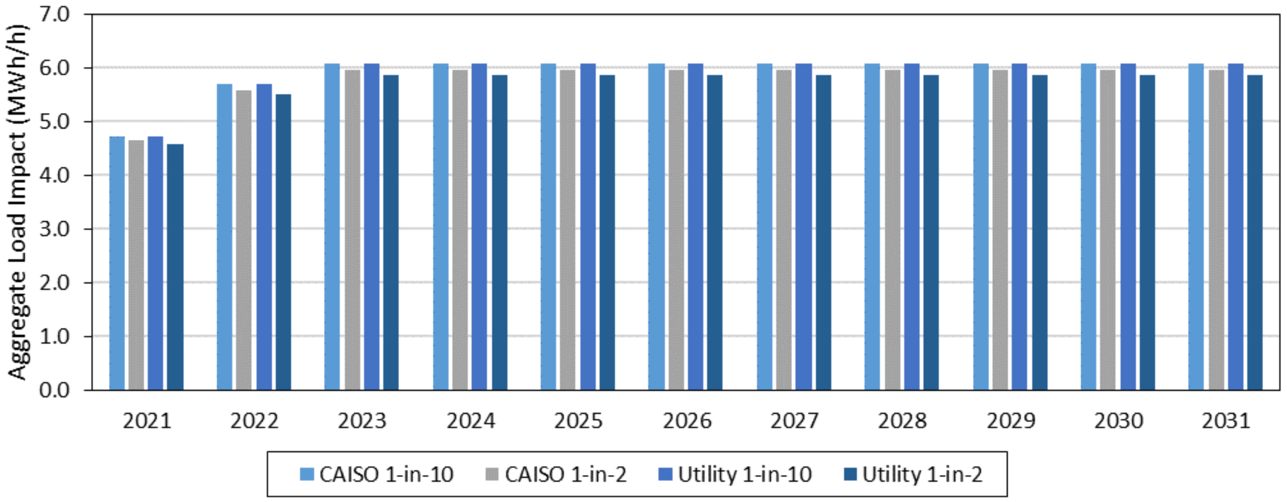
SDG&E *Ex-ante* Load Impacts:

by Year and Weather Scenario

Tiered Rate to EV-TOU-2



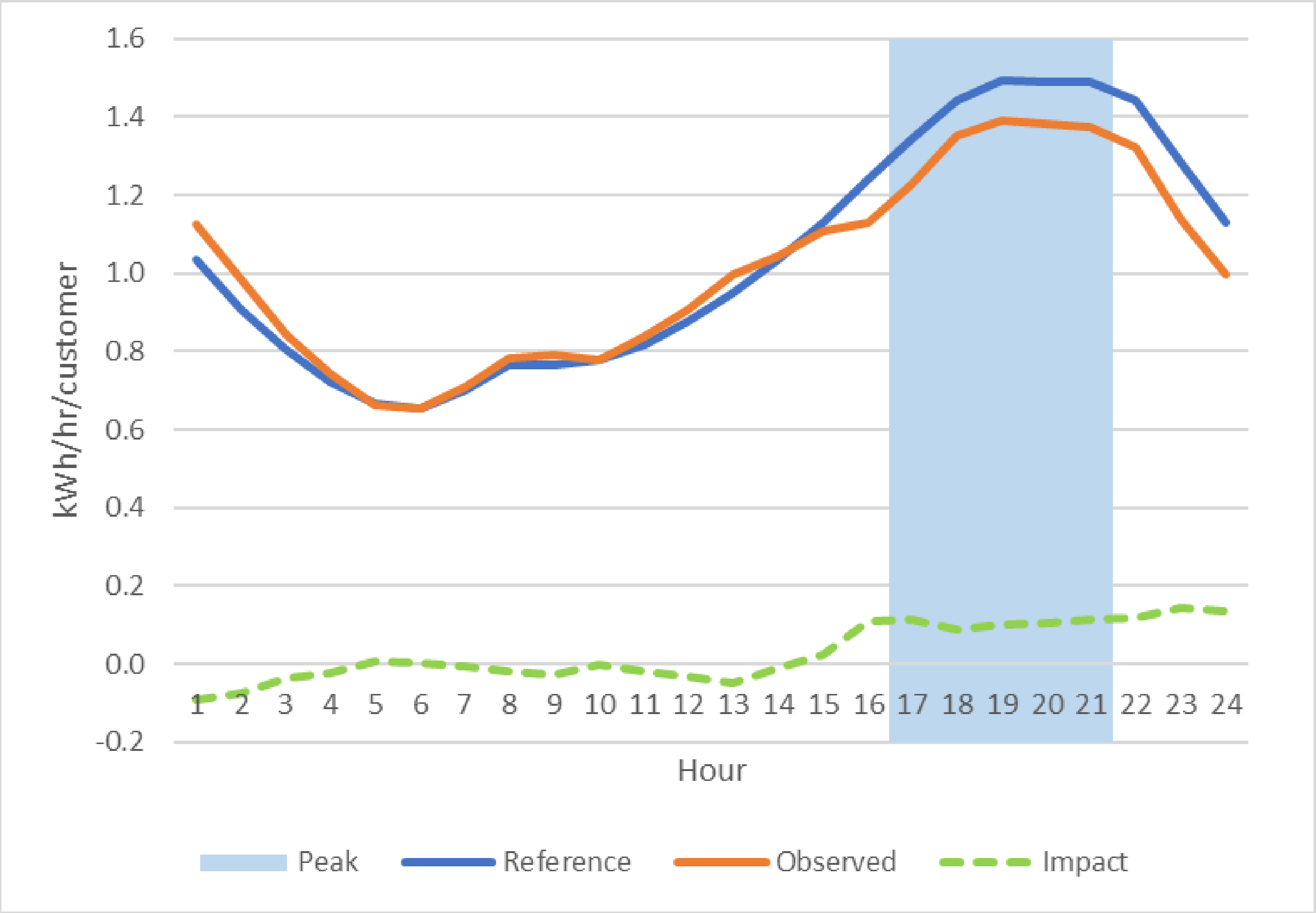
Tiered Rate to EV-TOU-5



Note: Aggregate load impacts above are during the RA window (4-9 p.m.) for the month of August

CHRISTENSEN ASSOCIATES ENERGY CONSULTING

PG&E EV2-A Ex-Ante Forecast:
Aug. 2021 PG&E 1-in-2 Peak Day



CHRISTENSEN ASSOCIATES ENERGY CONSULTING

Summary

- The results appear to reflect success in identifying EV adopters vs. those who had an EV during the entire analysis timeframe
- Time-of-use pricing appears to be very effective at moving EV charging into overnight hours (midnight to 6 a.m.)
- The magnitude of customer response increased with the TOU price differential between the SDG&E EV-TOU-2 and EV-TOU-5 rates

Questions?

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Appendix

- The following provides a discussion of how the TOU analysis is impacted depending what point, during the analysis period, a customer begins charging an EV

Need to Know When EV Charging Begins:
Get EV and adopt TOU at the same time

Pre-treatment period

Treatment period

On Tiered Rate

On EV-TOU Rate

Get EV and switch to EV-TOU at the same time

Time

In this case, you can't disentangle changes in usage due to beginning charging the EV and switching to the TOU rate because they happen at the same time.

Need to Know When EV Charging Begins: Adopt TOU after owning EV for some time

Pre-treatment period

Treatment period

On Tiered Rate

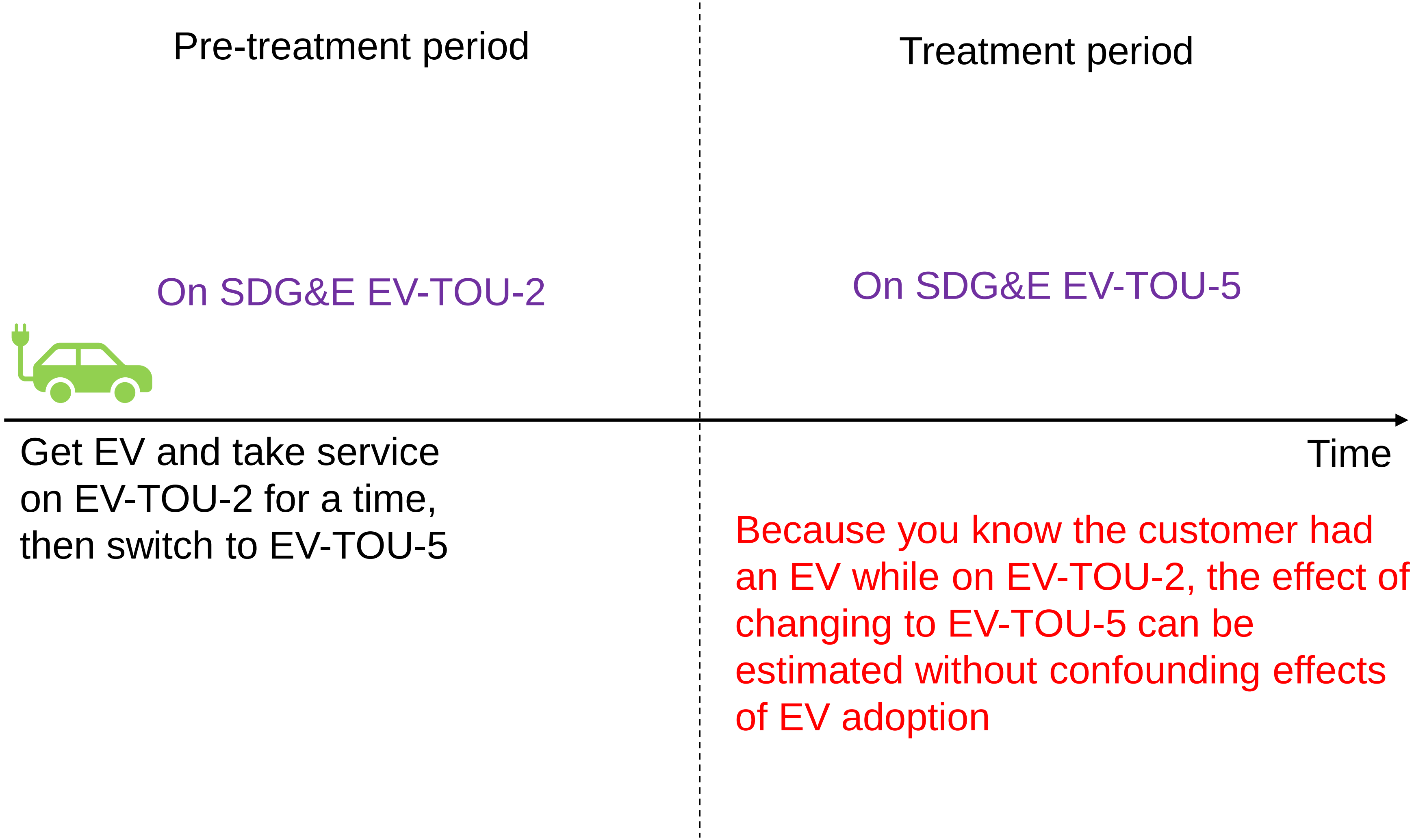
On EV-TOU Rate

Get EV, take service on tiered rate, then switch to EV-TOU

Time

In this case, you have information about their EV usage under the tiered rate, so you can estimate the effect of switching to the TOU rate.

SDG&E: No Problem for EV-TOU-2 to EV-TOU-5 Switchers



Get EV and take service on EV-TOU-2 for a time, then switch to EV-TOU-5

Because you know the customer had an EV while on EV-TOU-2, the effect of changing to EV-TOU-5 can be estimated without confounding effects of EV adoption

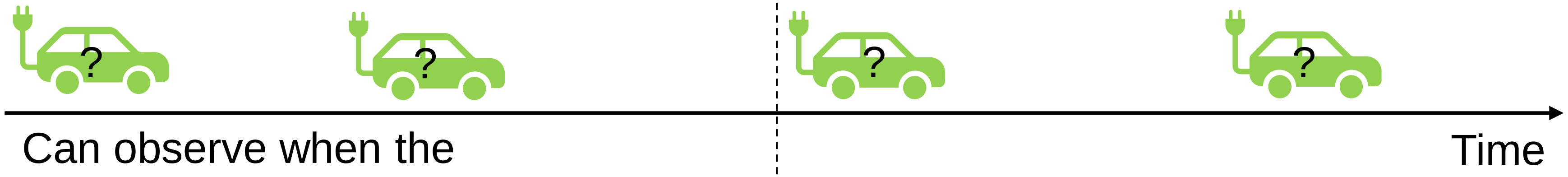
But Tiered Rate to EV-TOU Switchers Could Have Had an EV at Any Point

Pre-treatment period

Treatment period

On Tiered Rate

On EV-TOU Rate



Can observe when the rate change occurred, but not when EV charging began

Because you don’t know when the customer began charging an EV, you can’t distinguish between the effects of EV adoption and TOU rate adoption

August 2020 DR Statistics

April 2021

Together, Building
a Better California

DR Statistics during August 2020 Heatwave

	RA Commitment [1]	RA Commitment (enrollment adjusted) [2]	Bid Amounts [3]	Dispatch Price [4]	MW Delivered CAISO Settlement [5]	MW Delivered Ex Post [6]
	MW	MW	MW	$/MWh	MW	MW
8/14/2020	335	296	273	1,089	180	231
8/15/2020	335	296	212	1,038	179	214
8/16/2020	335	296	221	750	57	155
8/17/2020	335	296	290	940	204	242
8/18/2020	335	296	293	1,127	212	262
8/19/2020	335	296	272	1,020	33	20
8/20/2020	335	296	237	193	0	0
8/21/2020	335	296	271	Refer to Footnote [7]		

[1] Sum of RA commitment of BIP, CBP, and SmartAC programs per the 2019 Total IOU Demand Response Program Totals, not adjusted for distribution loss factors.
[2] Ex Ante forecasted adjusted using August 2020 enrollment from public ILP Report (per customer Ex Ante load impact * August 2020 enrollment).
[3] Sum of maximum coincident RDRR and PDR hourly bids between HE 17 to HE 21.
[4] Maximum of market dispatch prices for hours where there were awards.
[5] Sum of maximum coincident RDRR and PDR settlement MW between HE 17 to HE 21.
[6] Sum of maximum coincident Ex Post data for BIP, CBP, and SmartAC from April 2021 public Load Impact filing.
[7] No market awards received on this trade date.

- Difference in measurement methods (regression, day matching), program enrollment, and customer load due to COVID-19 contribute to gaps between planning, bids, settlement, and Ex Post.
- MW Delivered per CAISO Settlement on 8/16 reflects of partial-hour dispatch. Ex Post reflects longer retail event.
- MW Delivered per CAISO Settlement on 8/19 reflects that only a subset of market resources received awards.

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PY20 DR LI Workshop

SDG&E Heatwave Performance

(August 14th, 2021- August 21st, 2021)

Prepared by Lizzette Garcia-Rodriguez.

Electric Load Analysis

April 30th, 2021

Definitions

RA commitment= Based on

- ✓ PY19 Ex-ante load impacts for August 2020 (MW) without COVID-19 assumption
- ✓ PY20 Ex-ante load impacts for August 2020 (MW) with COVID-19 assumptions

Results are at the program level. The average is based on RA hours (4pm-9pm) and SDG&E 1in2 weather conditions.

Amount delivered = PY20 Official Ex-post load impact estimates. Results are at the program level. The average is based on event hours.

Settlement based on CAISO = Results are at the Proxy Demand Resource (PDR) level but for the purpose of the data request results were added at the program level. The average is based on event hours.

Dispatch prices = Marketing clearing prices.

SDG&E Heatwave Performance

Date	Marketing clearing prices	CAISO Settlement (MW)	Amount Delivered (MW)	Max Temperature at Miramar	SDG&E triggered a program?
8/14/2020	$597.97	2.7	10.3	95	All DR programs
8/15/2020	N/A	N/A	N/A	94	N
8/16/2020	N/A	N/A	N/A	89	N
8/17/2020	$988.96	0.8	10.5	91	All DR programs
8/18/2020- CAISO Peak Day	$1,446.48	1.8	12.8	98	All DR programs
8/19/2020	$514.88	5.9	12.0	91	All DR programs
8/20/2020	$500.80	0.1	0.4	93	Only BIP
8/21/2020	$142.06	5.8	13.0	96	All DR programs
Total		**17.2**	**59.1**		
Average	**$698.52**	**3.4***	**11.7***		

RA commitment (PY19 Ex-ante load impacts for August 2020 (MW) without COVID-19 assumptions)=14 MW
RA commitment (PY20 Ex-ante load impacts for August 2020 (MW) with COVID-19 assumptions) =9.6 MW
*The average does not include 8/20

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PERFORMANCE OF SCE SUPPLY SIDE PORTFOLIO IN AUGUST 2020

DRMEC, APRIL 30, 2021

Demand Side Analytics

DATA DRIVEN RESEARCH AND INSIGHTS

KEY STATISTICS FOR SCE SUPPLY-SIDE PROGRAMS DURING AUGUST HEATWAVE

	CAISO Settlement [1]	Dispatch Price (Real-Time	MW Delivered, PY 2020 Ex Post [4]	RA Commitment [5]	RA Commitment [6]
	[MW]	[$/MWh]	[MW]	[MW]	[MW]
8/14/2020	610	1,016	759.7	884	741
8/15/2020	575	751	797.4	884	741
8/16/2020	546	325	724.9	884	741
8/17/2020	582	790	816.2	884	741
8/18/2020	586	968	799	884	741
8/19/2020	See Footnote 3.	See Footnote 3.	See Footnote 3.	884	741
8/20/2020				884	741
8/21/2020				884	741

[1] Maximum of API, BIP, SDP - R/C, SEP, CBP during hours in which CAISO settlement data is available.
[2] Maximum of real-time market dispatch price ($/MWh), when available.
[3] No CAISO settlement data or dispatch prices available on these days. API, BIP, SDP - R/C, SEP, CBP were not dispatched and/or awarded.
[4] Average of program-level load impacts per LIP for API, BIP, SDP - R/C, SEP, CBP during hours when all programs are dispatched
[5] Includes RA Commitment of API, BIP, SDP - R/C, SEP, CBP forecasted for 2020, from the PY2018 evaluation (filed April 1, 2019) before accounting for distribution loss factor (DLF).
[6] RA Commitment forecasted for 2021, using PY2020 analysis (filed April 1, 2021) before accounting for distribution loss factor.

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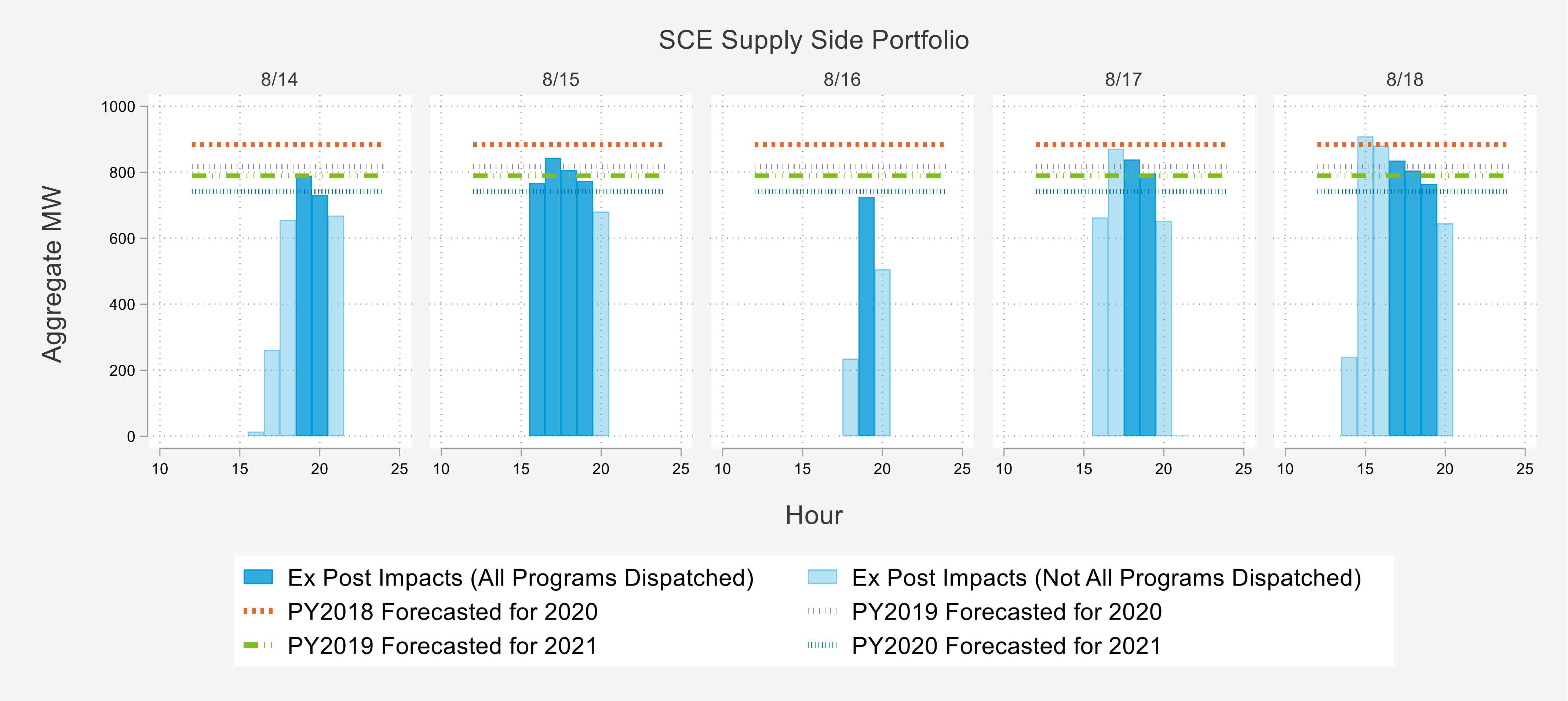
EX POST PERFORMANCE COMPARED TO DISPATCHED MW



Sum of BIP, SDP-R, SDP-C, SEP, AP-I, CBP-DO, and CBP-DA

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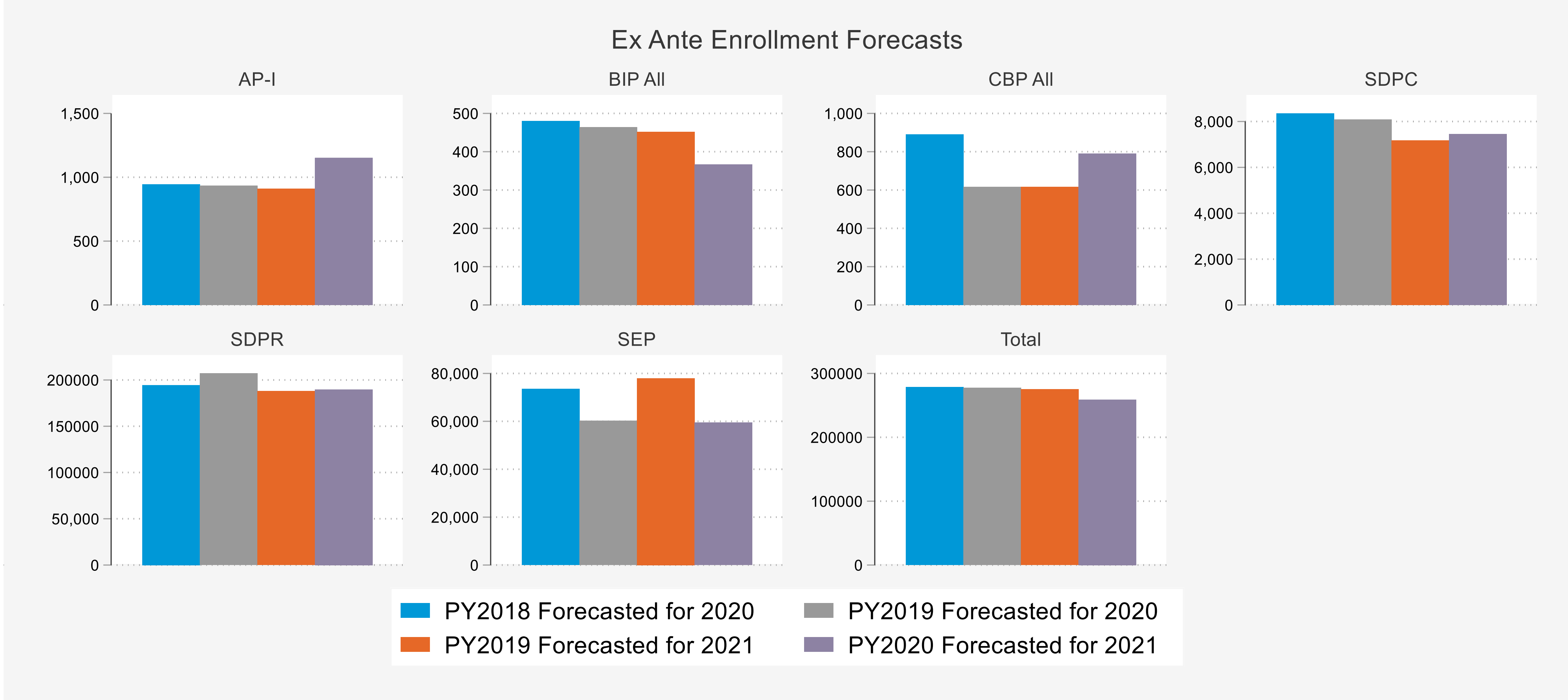
APPENDIX

ENROLLMENT FORECAST CHANGES BY EVALUATION YEAR AND PROGRAM



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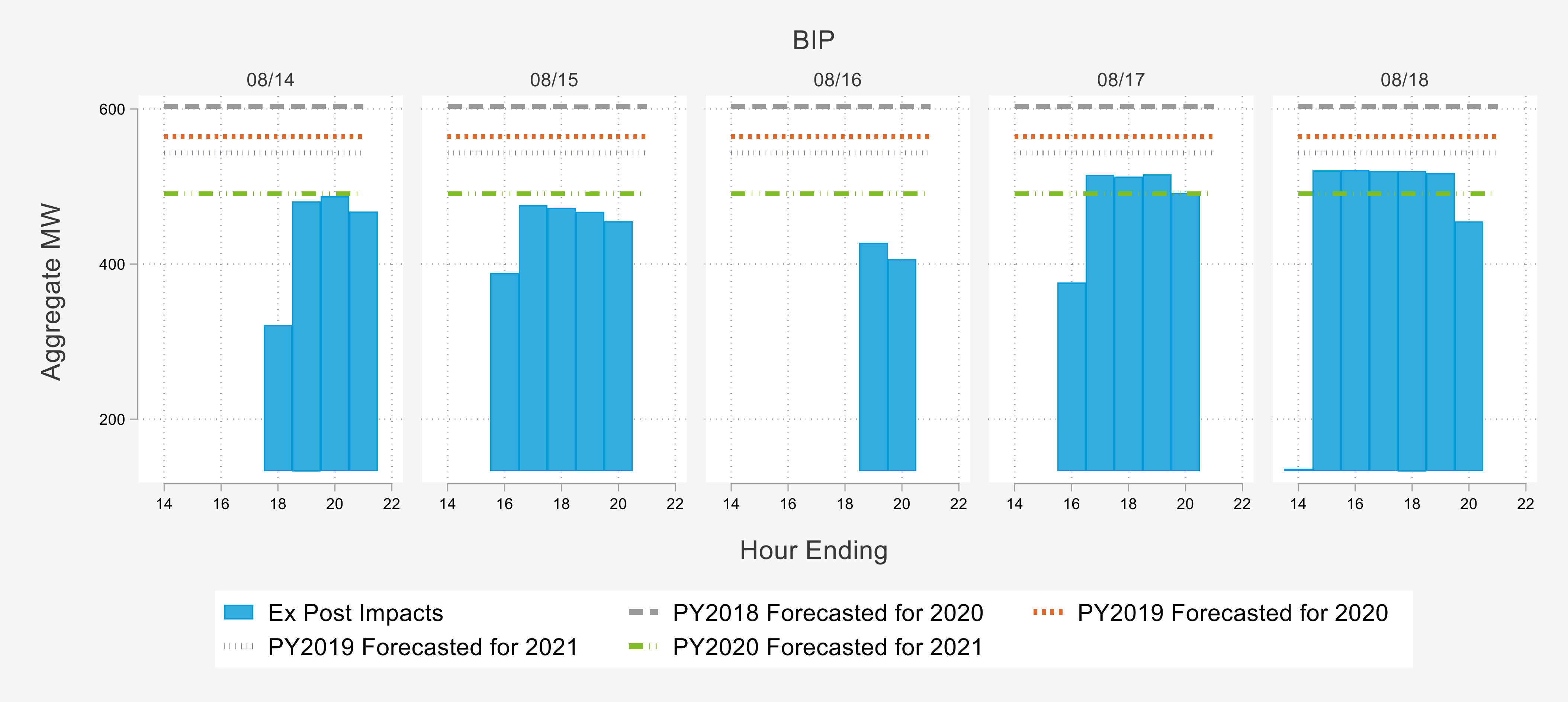
AUGUST PERFORMANCE COMPARED TO RA VALUES - BIP



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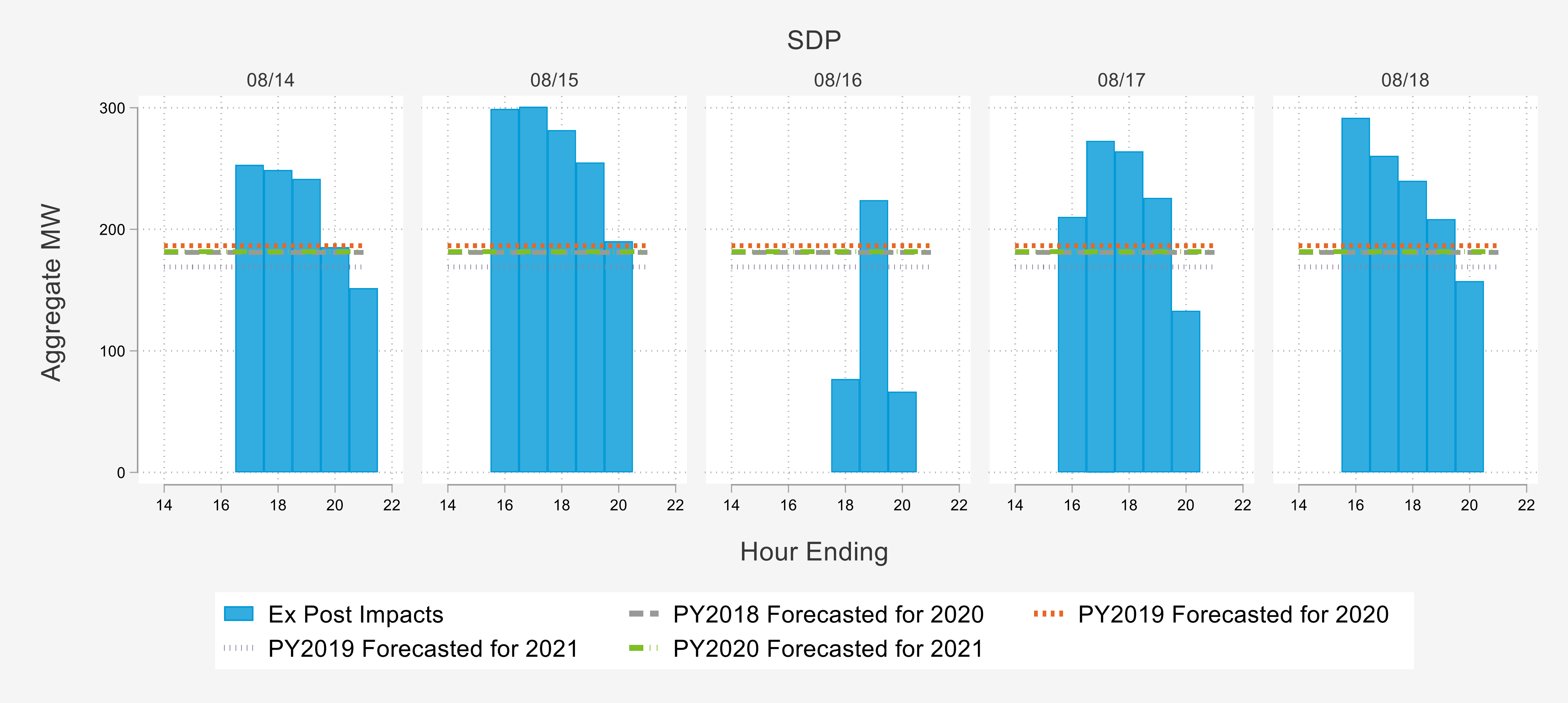
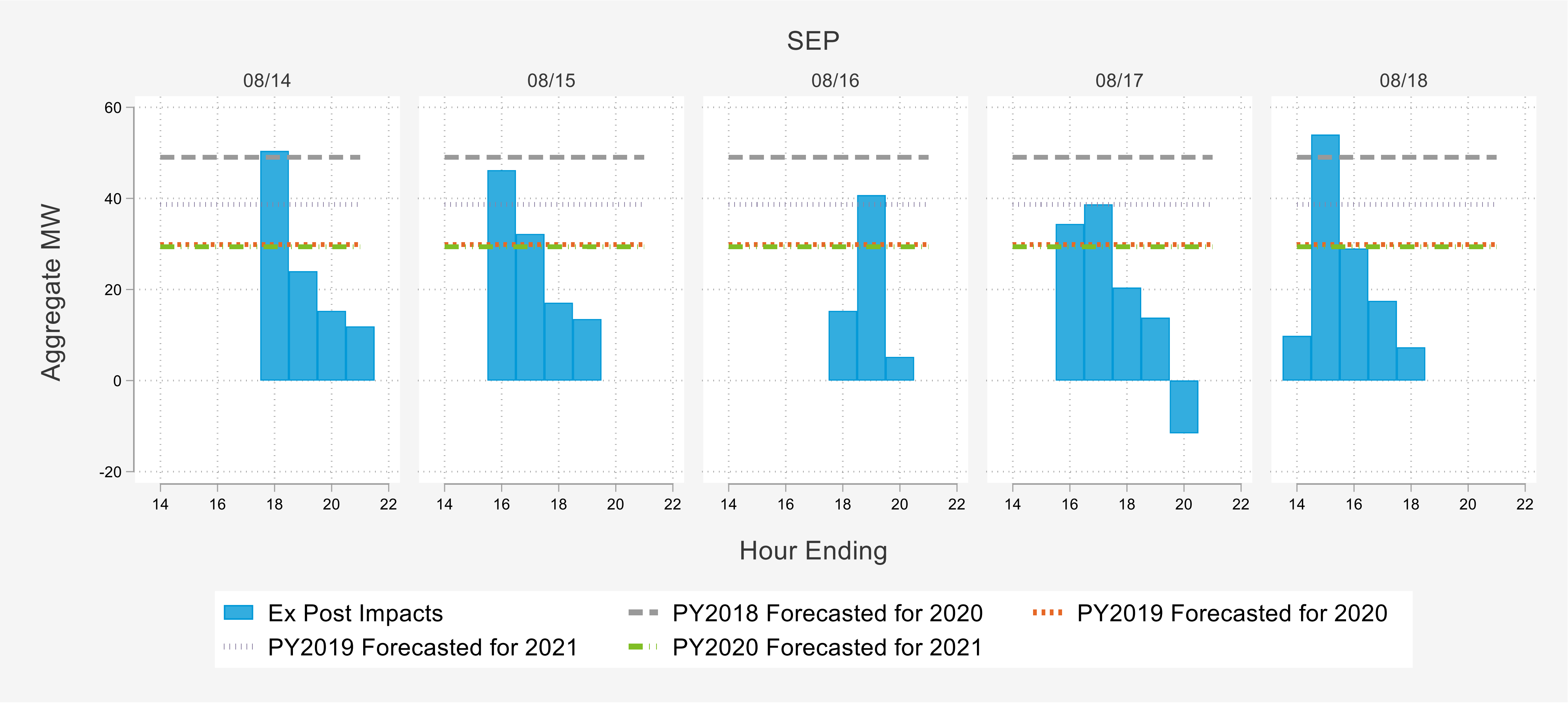
AUGUST PERFORMANCE COMPARED TO RA VALUES - SDP



AUGUST PERFORMANCE COMPARED TO RA VALUES - SEP



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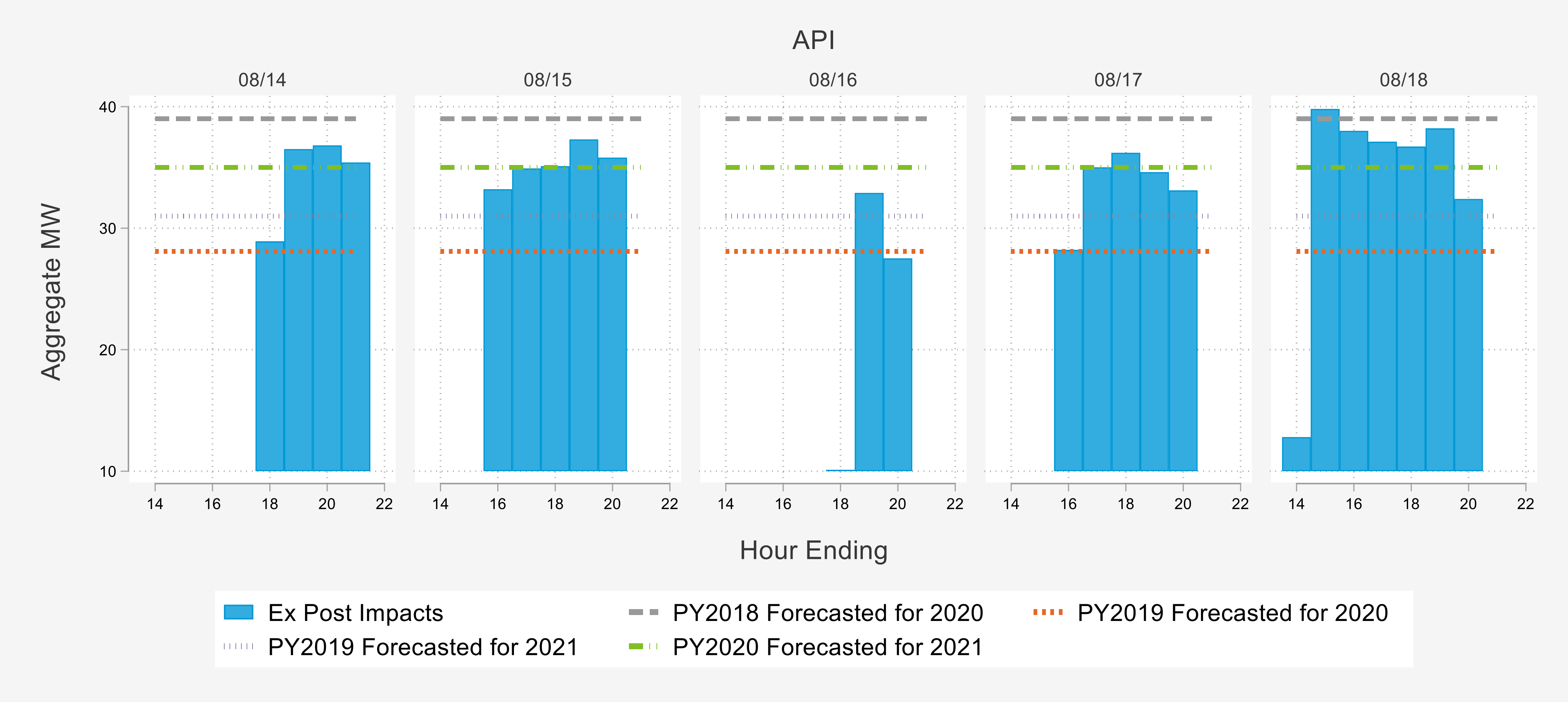
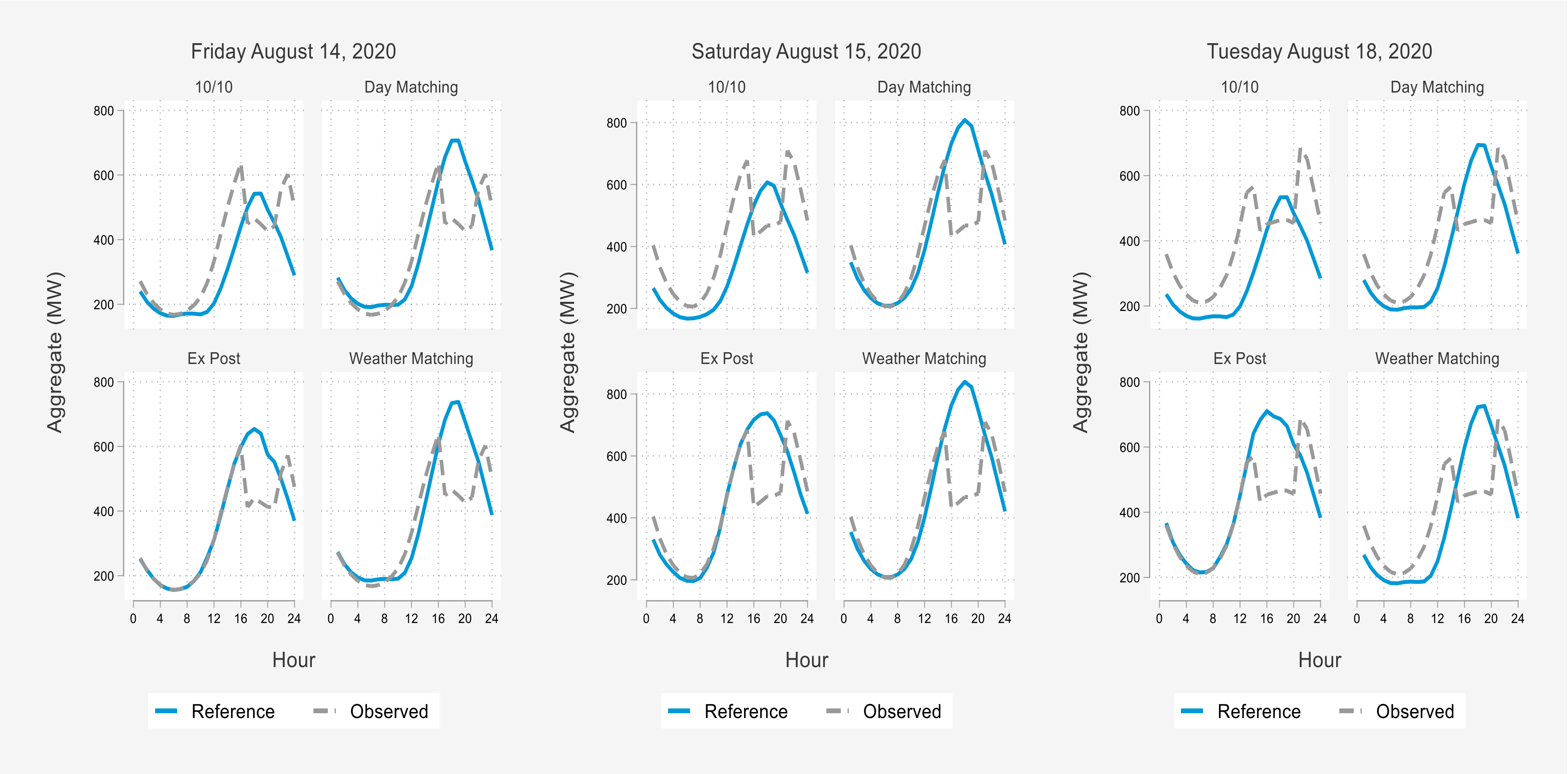
AUGUST PERFORMANCE COMPARED TO RA VALUES – AP-I



MOST DAY-MATCHING BASELINES WILL UNDER-REPORT IMPACTS FOR WEATHER SENSITIVE PROGRAMS



SDP-R

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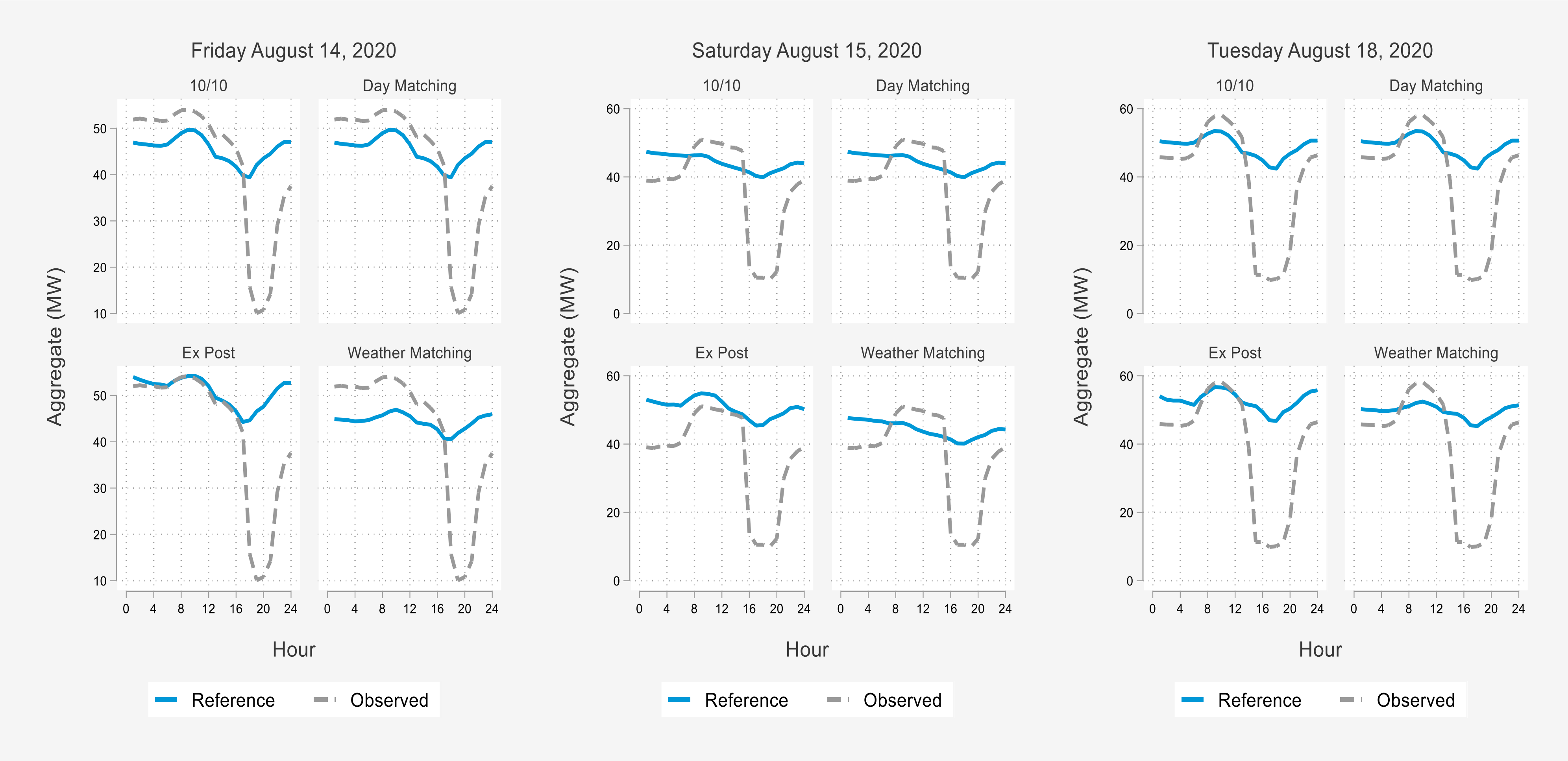
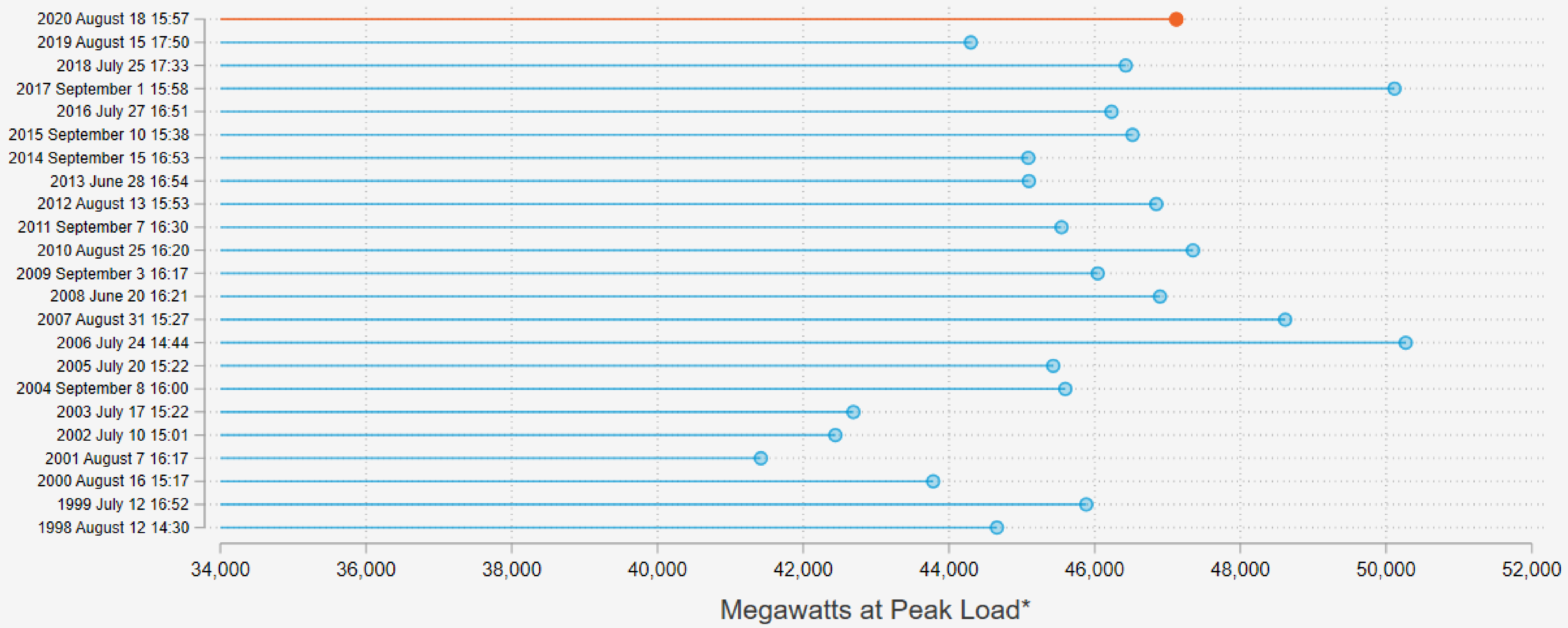
BASELINES PERFORM BETTER FOR NON-WEATHER-SENSITIVE PROGRAMS



AP-I

CAISO PEAKS WERE HIGH, BUT NOT OUTSIDE OF HISTORICAL PEAKS



Source: http://www.caiso.com/Documents/CaliforniaISOPeakLoadHistory.pdf

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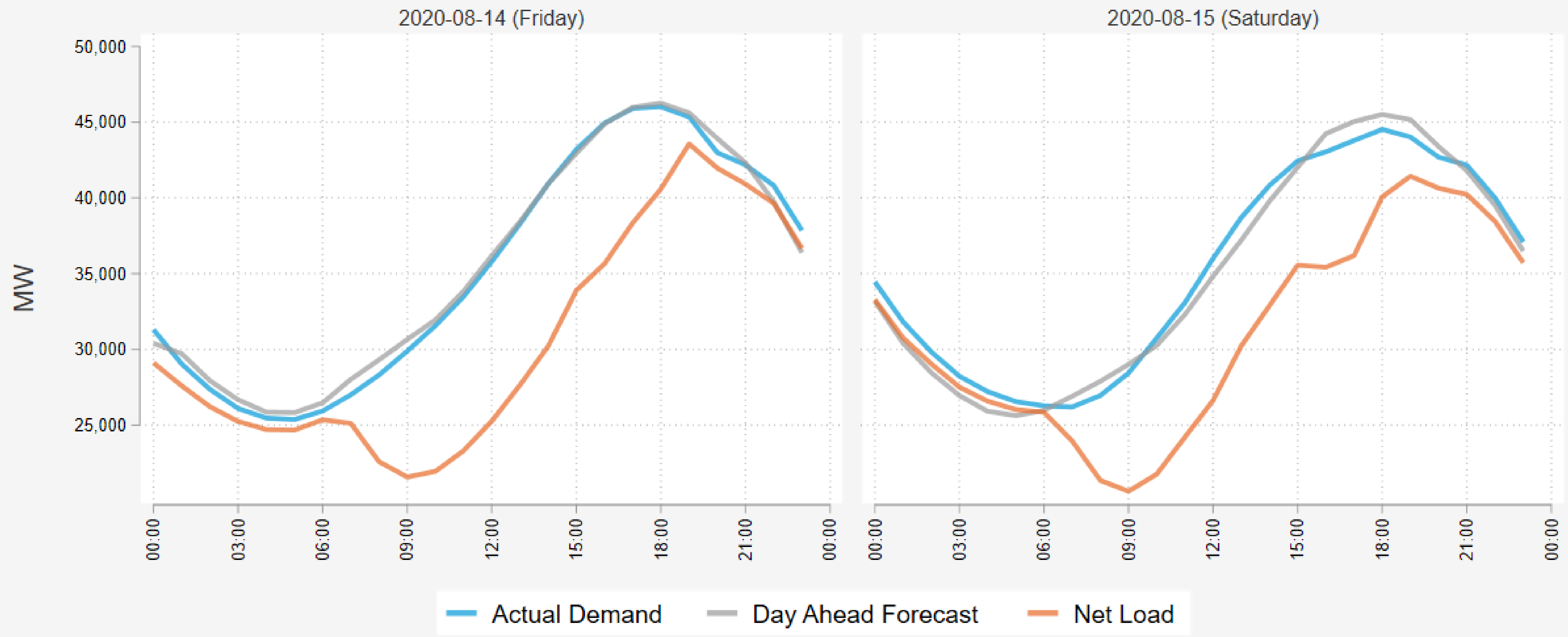
ON AUGUST 14TH AND AUGUST 15TH, CAISO CALLED FOR ROLLING BLACKOUTS



Source data: https://www.eia.gov/opendata/qb.php?category=2123635

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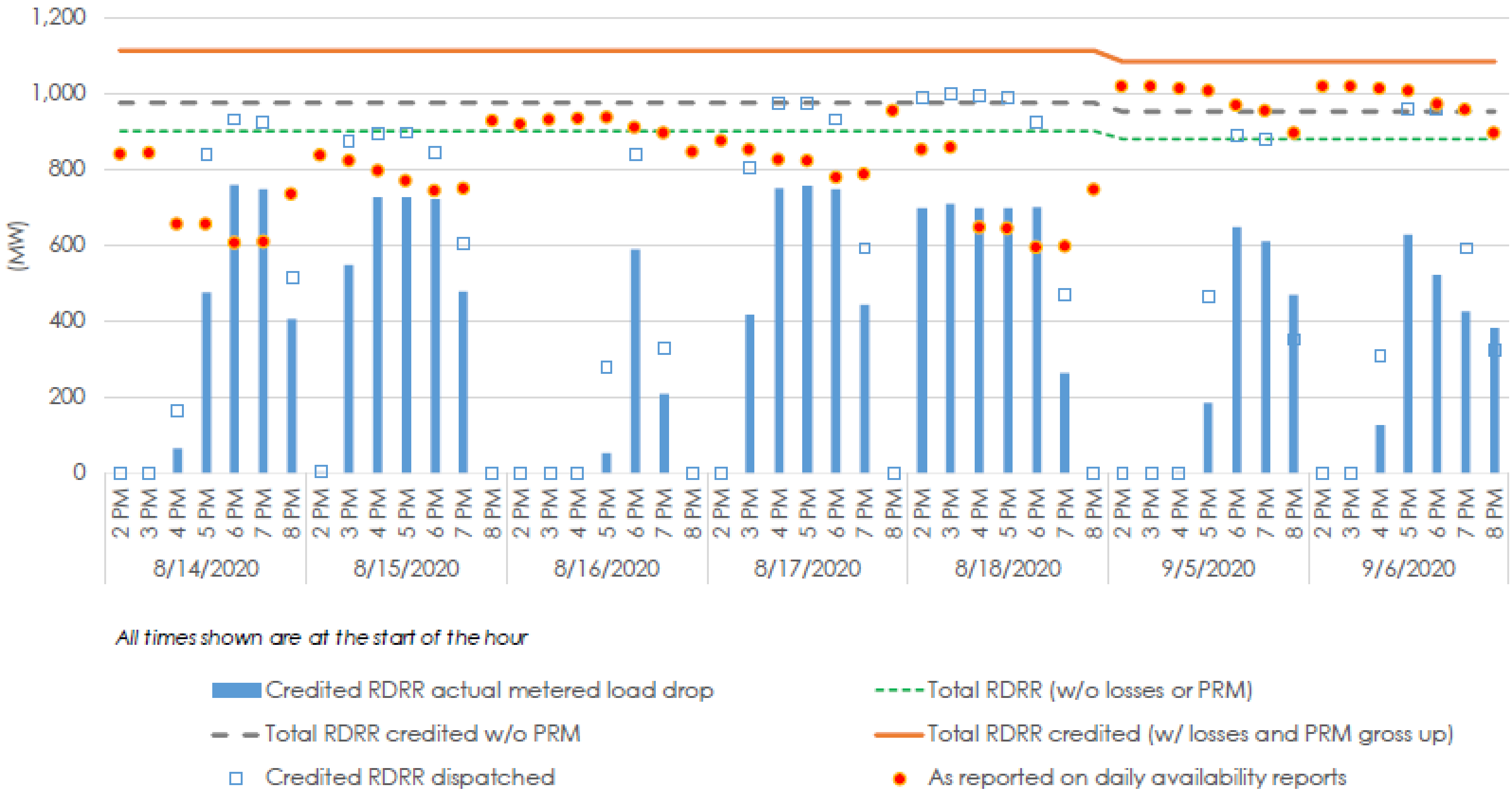
ALL RESOURCES, INCLUDING DEMAND RESPONSE WERE NEEDED TO AVOID MORE BROADER ROLLING BLACKOUTS

Figure 4.5: Credited IOU Reliability Demand Response Resource Real-Time Availability, Dispatch, and Performance



- Based on the CAISO root cause analysis, DR underperformed compared to resource adequacy
- All of their estimates are based 10-in-10 day matching baselines, which are not the most accurate approach for weather sensitive sites
- Not all of the resources were dispatched

QUESTIONS?

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