Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

REPORT

# 2021 SCE Real Time Pricing Demand Response Evaluation

*Confidential information is redacted and denoted with black highlighting:* [redacted]

**April 1, 2022**

**Prepared for Southern California Edison**

**By:**

**Andrea Hylant**
**Adriana Ciccone**
**Josh Bode**
**Demand Side Analytics**

**CALMAC Study ID: SCE0465**

# TABLE OF CONTENTS


1 EXECUTIVE SUMMARY ..... 3
2 PROGRAM DESCRIPTION ..... 6
2.1 KEY RESEARCH QUESTIONS ..... 6
2.2 PROGRAM DESCRIPTION ..... 6
2.3 PARTICIPANT CHARACTERISTICS ..... 8
2.4 2021 EVENT CONDITIONS ..... 9
2.5 EFFECT OF COVID-19 PANDEMIC ON PARTICIPANT LOADS ..... 10
2.6 PROGRAM CHARACTERISTICS THAT INFLUENCE EVALUATION ..... 11
3 EVALUATION METHODOLOGY ..... 13
3.1 OVERVIEW OF EVALUATION METHOD SELECTED ..... 15
Synthetic Controls ..... 15
Out of Sample Testing ..... 16
Ex Post Model ..... 17
Ex Ante Reference Load Model ..... 19
3.2 EVENT MODEL SPECIFICATION ..... 20
4 EX POST RESULTS ..... 22
Measuring RTP Impacts During the Peak Window ..... 22
4.1 OVERALL RESULTS ..... 23
4.2 RESULTS BY CATEGORY ..... 28
4.3 COMPARISON TO PRIOR YEAR ..... 30
4.4 KEY FINDINGS ..... 32
5 EX ANTE RESULTS ..... 33
5.1 ENROLLMENT FORECAST ..... 33
5.2 OVERALL RESULTS ..... 33
5.3 RESULTS BY CATEGORY ..... 36
5.4 COMPARISON TO PRIOR YEAR ..... 36
6 DISCUSSION ..... 38
7 APPENDIX: EVALUATION METHODOLOGY ..... 39
Demand Response Evaluation Methods ..... 39
Model Selection ..... 41
8 APPENDIX: RESULTS FOR EVENT-BASED MODEL ..... 45

Ex Post Modeling ..... 45
Ex Post Results ..... 47
Ex Ante Results ..... 50
9 APPENDIX: EX POST RESULTS BY CATEGORY FOR SPECIFIC DAYS IN LOAD IMPACT TABLES ..... 53

# 1 EXECUTIVE SUMMARY

The Real-Time Pricing Program offers commercial and industrial customers the opportunity to react daily to price signals and reduce loads when prices are high. Each day, the next days' hourly prices are tied directly to the daily maximum temperature in Downtown Los Angeles, grouped in to one of seven day types: Hot Summer Weekday, Moderate Summer Weekday, Mild Summer Weekday, High Cost Winter Weekday, Low Cost Winter Weekday, High Cost Weekend and Low Cost Weekend.

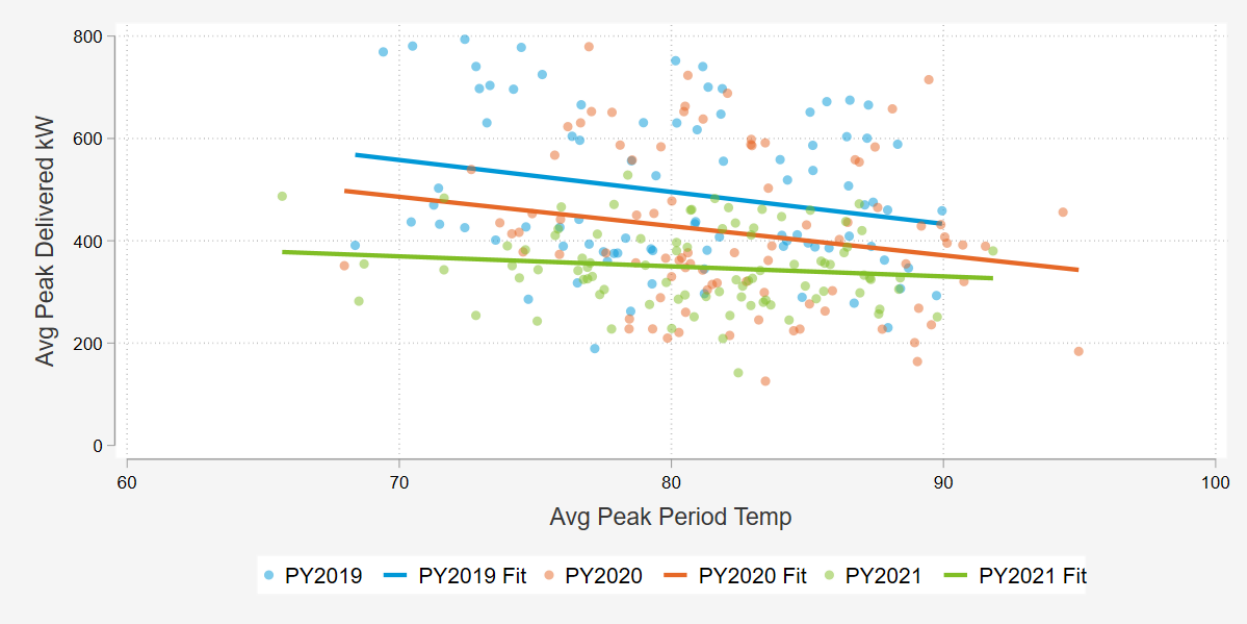
The RTP program delivered 2.37MW during the 4-9pm window on Hot Summer Weekdays: a 7.6% impact. As RTP prices are the highest on these days relative to the otherwise applicable tariff (OAT), ex post impacts are predictably higher on Hot Summer Weekdays, while impacts decline in Moderate and Mild Summer Weekdays. While there is no statistical difference in consumption between High Cost and Low Cost Winter Weekdays, there is a reduction in consumption during the weekend peak on High Cost Weekends compared to Low Cost Weekends.

Table 1: Ex Post Peak Period Impacts by Average Day Type

| RTP Day Type | # Dispatched | Average Customer (kW) | | | | | Agg. Impact (MW) |
|---|---|---|---|---|---|---|---|
| | | Ref. Load | Obs. Load | Impact | 95% CI | % Impact | |
| Hot Summer Weekday | 104 | 297.70 | 275.03 | 22.67 | 19.63 - 25.72 | 7.6 | 2.37 |
| Moderate Summer Weekday | 103 | 283.62 | 291.43 | -7.81 | -10.85 - -4.76 | -2.8 | -0.80 |
| Mild Summer Weekday | 103 | 290.47 | 305.43 | -14.97 | -18.01 - -11.92 | -5.2 | -1.54 |
| High Cost Winter Weekday | 111 | 362.54 | 367.73 | -5.19 | -8.24 - -2.15 | -1.4 | -0.58 |
| Low Cost Winter Weekday | 110 | 324.83 | 329.41 | -4.58 | -7.62 - -1.53 | -1.4 | -0.50 |
| High Cost Weekend | 105 | 243.08 | 221.57 | 21.51 | 18.47 - 24.55 | 8.8 | 2.26 |
| Low Cost Weekend | 109 | 225.65 | 224.60 | 1.04 | -2.00 - 4.09 | 0.5 | 0.11 |

As with all load modeling over the last two years, a key question for this year's evaluation is the extent to which the COVID-19 pandemic influenced RTP customer loads. Some sectors and industries saw dramatic shifts in energy use and patterns of consumption. RTP customers are mainly large industrial customers who generally saw moderate declines in consumption in PY2020, which continued in to PY2021. This is shown in Figure 1, where peak loads and temperatures in PY2019, PY2020, and PY2021 are plotted for the same set of customers on summer weekdays. As temperatures increase, loads decline, consistent with the intention of the RTP pricing schedules. Because load patterns have shifted for this population over time, we estimate impacts as a function of a new post-COVID baseline.

Figure 1: Effect of COVID-19 on Temperature-Load Relationship




It is clear from the figure that the participant loads in the summer of 2020 were lower than in the prior year. In 2021, we see another drop in participant loads for the summer of 2021. This can partially be attributed to a change in consumption patterns in some large RTP customers. The relationship between temperature and loads, where temperature is a proxy for the RTP rate schedule that a customer experienced, is consistent from 2019 to 2020, but is less strongly correlated in 2021.

RTP enrollments are expected to decline over time, from 103 in 2021 to 84 enrolled customers in 2032. Program load impacts of approximately 7.81MW during the 4pm-9pm hours are projected. Load impacts by hour in the RA window are shown in Table 3. Due to the RTP treatment being determined by weather conditions, no weather variables are included in the ex ante specification, so the only difference between these scenarios is the RTP day type associated with the CAISO and SCE 1-in-2 and 1-in-10 weather scenarios. Including weather variables in the modeling of RTP impacts would risk misattributing the effect of the price signals to the effect of weather. This would lead to incorrect estimates of program effects. All August Monthly Peak days are associated with the 'Hot Summer Weekday' RTP day type and have the same rate schedule applied. Finally, the decrease in impacts over time is attributable to a decline in program enrollment over the forecast horizon.

Table 2: RTP Aggregate Program Ex Ante Impacts (MW) - August Peak Day from 4pm-9pm

| Forecast Year | SCE 1-in-2 | SCE 1-in-10 | CAISO 1-in-2 | CAISO 1-in-10 |
|---|---|---|---|---|
| 2022 | 2.51 | 2.51 | 2.51 | 2.51 |
| 2023 | 2.41 | 2.41 | 2.41 | 2.41 |
| 2024 | 2.26 | 2.26 | 2.26 | 2.26 |
| 2025 | 2.15 | 2.15 | 2.15 | 2.15 |
| 2026 | 2.15 | 2.15 | 2.15 | 2.15 |
| 2027 | 2.15 | 2.15 | 2.15 | 2.15 |
| 2028 | 2.15 | 2.15 | 2.15 | 2.15 |
| 2029 | 2.15 | 2.15 | 2.15 | 2.15 |
| 2030 | 2.15 | 2.15 | 2.15 | 2.15 |
| 2031 | 2.15 | 2.15 | 2.15 | 2.15 |
| 2032 | 2.15 | 2.15 | 2.15 | 2.15 |

Table 3: RTP Aggregate Program Ex Ante Impacts (MW) – 2022 August Peak Day by Hour

| Hour Ending | SCE 1-in-2 | SCE 1-in-10 | CAISO 1-in-2 | CAISO 1-in-10 |
|---|---|---|---|---|
| Avg. 4pm-9pm | 2.51 | 2.51 | 2.51 | 2.51 |
| 17 | -0.77 | -0.77 | -0.77 | -0.77 |
| 18 | 0.84 | 0.84 | 0.84 | 0.84 |
| 19 | 4.83 | 4.83 | 4.83 | 4.83 |
| 20 | 4.36 | 4.36 | 4.36 | 4.36 |
| 21 | 3.30 | 3.30 | 3.30 | 3.30 |

The RTP program can provide a small but measurable amount of demand response impacts during the 6pm-9pm period on Hot Summer Weekdays, when prices relative to the otherwise applicable tariff are high. The program has many customers who are dually enrolled in other demand response programs, making attribution of impacts challenging. Similarly, the program is dominated by several large industrial accounts that provide the majority of the load shed for the program.