



2020 Load Impact Evaluation of Southern California Edison's Default Time-of-Use Pilot

Prepared for:

Southern California Edison Co.

April 1, 2021

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CALMAC Study ID SCE0450

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1 Executive Summary

This report documents the 2020 load impact evaluation of Southern California Edison's Residential Default Time-of-Use (TOU) pricing pilot. This pilot was implemented in response to California Public Utilities Commission (CPUC) Decision 15-07-001. A key objective of the pilot is to develop insights that will help guide SCE's approach to implementation of default TOU pricing for the majority of residential electricity customers and the CPUC's policy decisions regarding default pricing.

Findings from the first summer of the pilot—June through September 2018—are documented in the “Default Time-Of-Use Pricing Pilot Interim Evaluation” dated April 1, 2019 (hereafter referred to as the Interim Report). The Interim Report contains detailed background information on the pilot, describes the pilot design and the load impact evaluation methodology, discusses SCE's pilot implementation and treatments, and presents load impacts for the first summer period. It also presents structural bill impacts and summarizes pre-enrollment opt-out rates. Findings from the first winter and the full first year of the pilot are documented in the “Default Time-Of-Use Pricing Pilot Final Evaluation” dated November 1, 2019 (hereafter referred to as the Final Report). The Final Report focuses primarily on load impacts from the winter period in 2018 and 2019 as well as bill impacts for the first year of the pilot. The winter results provide load impacts for the entire winter rate period of October 2018 through May 2019. Behavioral bill impacts and total bill impacts are provided for the full first year of the pilot, from June 2018 through May 2019. Customer attrition throughout the first year is also included in the Final Report. Findings from the second summer can be found in the 2019 evaluation report.¹

The primary objective of this report is to document the findings of an ex post (after the fact) study that estimates hourly load impacts for the winter of 2019/2020 (October 2019 through May 2020) and summer of 2020 (June through September 2020). An additional objective is to provide an ex ante (forward looking) forecast for the next eleven years (2021 to 2031) of program operations. The ex ante study provides estimated hourly load impacts given SCE's default TOU enrollment forecast and given weather conditions that reflect SCE and California Independent System Operator (CAISO) electric system peaks.

1.1 Pilot Background and Design

The default TOU pilot tested two different TOU rate options: Rate 4 and Rate 5. Approximately 400,000 households were assigned to one of the TOU rates (200,000 to each rate), and an additional 200,000 were retained in the study on the standard tiered rate to act as a control group for those who were placed on the new tariffs. After receiving multiple notifications regarding the fact that their rate will change if they did not take action by a certain date, customers had the option of opting out prior to the rate change and staying either on their otherwise applicable tariff or choosing an alternative rate plan other than the one they were to

¹ 2019 Load Impact Evaluation of Southern California Edison's Default Time-of-Use Pilot. Nexant. April 1, 2020.

be defaulted on. If a customer took no action, they were placed on the default rate associated with their assigned group.²

Figure 1-1 and Figure 1-2 summarize the rate periods and prices for Rates 4 and 5. Importantly, the prices shown in the figures and discussed below do not reflect the baseline credit of 7¢/kWh that applies to each rate.³

Figure 1-1 Default Pilot Rate 4⁴

Day Type	Season	Hour Ending																							
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Weekday	Summer	Off-Peak (25¢)																Peak (40¢)							
	Winter	Off-Peak (24¢)								Super Off-Peak (22¢)								Mid-Peak (32¢)							
Weekend	Summer	Off-Peak (25¢)								Off-Peak (25¢)								Mid-Peak (33¢)							
	Winter	Off-Peak (24¢)								Super Off-Peak (22¢)								Mid-Peak (32¢)							

Figure 1-2: Default Pilot Rate 5

Day Type	Season	Hour Ending																							
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Weekday	Summer	Off-Peak (25¢)																Peak (50¢)							
	Winter	Off-Peak (25¢)								Super Off-Peak (22¢)								Mid-Peak (38¢)							
Weekend	Summer	Off-Peak (25¢)								Off-Peak (25¢)								Mid-Peak (38¢)							
	Winter	Off-Peak (25¢)								Super Off-Peak (22¢)								Mid-Peak (38¢)							

The pilot was structured as a randomized encouragement design (RED) experiment. With a RED, different randomly selected samples of customers are offered different experimental treatments (in this case, a TOU rate or different content or messaging in the recruitment materials) and another random group of customers is not offered anything (e.g., the control group). Some who are offered the treatment take it and some do not. Because each sample is a statistical clone of the other due to the random selection (especially in this case where sample sizes are quite large), comparing the behavior of the encouraged group with that of the control group allows for an unbiased assessment of the impact of the treatment. This analysis requires a two-step process in order to isolate the impact of the encouragement (e.g., the offer of a treatment) from the treatment itself, as explained more fully in Section 3.1.

Load impacts were estimated for four different climate regions in SCE's service territory (hot, moderate, cool, and Climate Zone 10). CARE/FERA customers in the hot climate region and Climate Zone 10 were not allowed to be enrolled on TOU tariffs using default recruitment. As such, comparisons across the two hot and two more moderate regions not only reflect differences in climate but also differences in the mix of customers. Also, differences in load impacts across customer segments at the service territory level reflect not just differences across segments, but also differences in the mix of customers across climate regions for each segment. These differences must be kept in mind when making comparisons across segments and climate regions. Load impacts were also estimated for each Local Capacity Area (LCA) in SCE's service territory and for net metered (NEM) and non-net metered (non-NEM) customers.

² Nexant was informed that during the summer of 2020 a small portion of customers originally designated as control group customers for the Default TOU Pilot evaluation received notification about being defaulted onto a TOU rate beginning October 1, 2020. Nexant does not believe these notifications influenced the load impact estimates in this evaluation in a substantive manner, and provides documentation and analysis supporting this position in Appendix A.

³ The baseline credit was equal to 7.027¢/kWh on January 1, 2020 and rose to 7.576¢/kWh on June 1, 2020.

⁴ Winter rates effective Jan 1, 2020. Summer rates effective June 1, 2020.

1.2 Overall Findings

1.2.1 Ex Post Load Impacts

Table 1-1: Peak Period Load Reductions on Average Weekdays

Metric	Rate 4		Rate 5	
	Winter	Summer	Winter	Summer
Peak Period Hours	4-9 PM	4-9 PM	5-8 PM	5-8 PM
% Impact	0.6%	1.1%	0.9%	1.3%
Absolute Impact (kW)	0.006 kW	0.016 kW	0.008 kW	0.019 kW

Key findings pertaining to the ex post analysis include:

- Default customers on both Rates 4 and 5 produced statistically significant, peak-period load reductions during the summer and winter seasons. Summer peak period load reductions were equal to 1.1% for Rate 4 and 1.3% for Rate 5. Winter peak period load reductions were slightly smaller, and averaged 0.6% for Rate 4 and 0.9% for Rate 5.
- Load reductions for the common hours shared by the two rates (5 to 8 PM) were greater for Rate 5 than for Rate 4 in both seasons, likely because of the higher peak period price per kWh. It's also possible the shorter peak period of Rate 5 allowed for greater flexibility in customer response to the price signal. The difference was statistically significant in the winter months but not during the summer.
- Statistically significant but small reductions in summer daily electricity use were found for the pilot populations as a whole and in Climate Zone 10, for both Rate 4 and Rate 5. Customers on Rate 4 in the moderate climate region increased their daily summer consumption by a small but statistically significant amount. Daily kWh impacts were mixed in the winter months: Rate 4 customers increased their daily kWh consumption and Rate 5 customers did not have statistically significant impacts.
- Peak period load reductions were largest in Climate Zone 10 in both summer and winter, but this segment did not include CARE/FERA customers. In the summer months, impacts were smallest in the hot and cool climate regions, and in the winter months impacts were smallest in the moderate and cool climate regions.
- In the summer months, peak period impacts were greatest in the Outside LA Basin region, however the difference between the Outside LA Basin region and the other two LCAs was not statistically significant (with the exception of Ventura/Big Creek for Rate 4, in absolute terms). In the winter months, the Outside LA Basin had the smallest load impacts.
- Rate 4 and Rate 5 NEM customers had statistically significant peak period load reductions equal to 2.2% and 3.4%, respectively, in the summer months. NEM customers on Rate 4 had small but statistically significant load increases in the winter (0.7%). Rate 5 NEM customers, on the other hand, had statistically significant peak load reductions in the winter (3.3%).

1.2.2 Persistence of Load Impacts

Key findings pertaining to the persistence analysis include:

- On average, customers on Rate 4 and Rate 5 produced statistically significant load reductions in the three summer seasons observed (2018, 2019, and 2020). At the service territory level, load impacts were greatest in the first summer (2018) and smallest in the most recent summer (2020). Customers on Rate 4 had load reductions equal to 1.5% in the first summer, 1.2% in the second summer, and 1.0% in the third summer. Rate 5 peak period impacts were 2.0% in 2018, 1.6% in 2019, and 1.1% in 2020. While the weather was slightly cooler on average in 2019 and 2020 compared to 2018, the load impacts were lower in 2019 and 2020 at comparable temperatures indicating second and third summer impacts were slightly lower when accounting for differences in weather. The summer season in 2020 coincided with the COVID-19 pandemic, which likely had an effect on customers' ability or motivation to respond to the TOU rate structure.
- The load impacts for the different climate regions on the two rates were generally smallest in the third summer compared to the first and second summers. The exception was customers on Rate 4 in the moderate climate region whose load impact increases from 2019 to 2020, but the differences are not statistically significant.

1.2.3 Ex Ante Load Impacts

Key findings pertaining to the ex ante analysis include:

- Enrollment on Rate 4 and Rate 5 will reach approximately 2.5 million by 2023 and then slowly decline to about 2.3 million by 2031 through natural attrition (approximately 1% per month). New enrollees will come from large waves of default enrollments (1.8 million) and new SCE customers (21,600 per month).
- Generally speaking, ex post and ex ante load impacts are larger under higher temperatures. As such, the largest ex ante impacts (0.019 to 0.027 kW per customer) are forecasted for 1-in-10 weather conditions during the hottest summer months (July, August, and September) for both Rate 4 and Rate 5. Winter ex ante load impacts are expected to be similar under 1-in-2 and 1-in-10 weather conditions.
- Ex ante forecasts account for the potential effects of the COVID-19 pandemic on customer demand and load impacts. Per-customer load impacts are expected to increase as the COVID-19 effect diminishes.
- The ex post load impacts fall between the ex ante load impacts under SCE 1-in-2 and SCE 1-in-10 weather conditions. This finding is expected as the average monthly temperatures between October 2019 and September 2020 are warmer than 1-in-2 conditions but cooler than 1-in-10 conditions.
- In 2022, after the default is completed, Rate 4 impacts are forecasted to reach 33.5 MW on the average August weekday under SCE 1-in-10 weather conditions and 26.6 MW under SCE 1-in-2 weather conditions during the resource adequacy window (4:00 to 9:00 PM). Rate 5 impacts during the RA window under SCE 1-in-10 weather conditions decline from a peak of 29.4 MW in August 2022 to 13.6 MW in August 2031 as the population grows smaller.
- For the default TOU rates as a whole (Rate 4 and Rate 5), aggregate impacts are expected to reach a maximum under August 1-in-2 conditions of 51.1 MW in 2024, and a maximum under August 1-in-10 conditions of 63.6 MW in 2023.