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STAFF PAPER

Joint Agency Staff Paper on Time-of-Use Load Impacts

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CPUC Staff Disclaimer:

Electric utilities may only modify their tariff formulas consistent with an order voted on by the full Commission and pursuant to the advice letter processes explained in CPUC General Order 96-B. The purpose of this analysis is to examine potential load impacts of rate design under various scenarios, not to propose any specific rate designs for consideration by the CPUC in any active proceeding. As such, the rates described herein are illustrative, and should not be viewed as a proposal by CPUC staff for any particular rate design.

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ABSTRACT

Under the auspices of the Joint Agency Steering Committee, the California Public Utilities, California Energy Commission, and the California Independent System Operator jointly conducted supplemental analysis for the *2015 Integrated Energy Policy Report* to examine potential forecast load impacts of possible changes to time-varying rates and other rate design elements. Dimensions of the analysis include residential fixed charges, time-of-use adoption rates, time-of-use periods for residential and nonresidential rate classes, and the transition to mandatory time-of-use and default critical peak pricing for small nonresidential customers. A critical policy question for the analysis is whether time-of-use rates might be able to smooth and flatten the net load curve (total electrical load less production of wind and solar generating facilities) by season to better match changing operational needs as renewable generation increases.

This staff paper, prepared by staff from the three agencies, summarizes two independent consultant studies undertaken at the request of the agencies. Work undertaken by Christensen Associates for the investor-owned utilities analyzed scenarios for both residential and nonresidential customers. The Energy Commission engaged MRW & Associates to analyze six scenarios for residential customers only. The time-of-use periods featured four seasons and at least three pricing periods for each season. Conceptual rates provided by the California Public Utilities Commission staff assumed a fixed customer charge and are designed for 2021 as a test year.

Keywords: Time-of-use, rate design, electricity, net load, fixed charges, residential, commercial, industrial, customers, price elasticity, peak, load impacts, peak period, demand response, opt-in, opt-out

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EXECUTIVE SUMMARY

The California Public Utilities, California Energy Commission, and the California Independent System Operator jointly conducted this supplemental analysis for the *2015 Integrated Energy Policy Report* to examine potential forecast load impacts of possible changes to time varying rates and other rate design elements. The analysis includes the following topics: residential fixed charges, time-of-use adoption rates, time-of-use periods for residential and non-residential rate classes, and the transition to mandatory time-of-use and default critical peak pricing for small non-residential customers. A critical policy question for the analysis is whether time-of-use rates might be able to smooth and flatten the net load curve by season to better match changing operational needs as renewable generation increases.

Work for the supplemental analysis is based on an hourly net-load analysis initiated by the California Independent System Operator in November 2014 to design new time-of-use periods that would align better with changing operational needs as more renewable generation is added. In March 2015, recommended TOU periods were released for further study. In April 2015, staff at the California Public Utilities Commission recommended time-of-use conceptual rates to conform to the period definitions. For this analysis, the rates assumed a fixed customer charge and a test year of 2021.

Scenarios 1-4 consider rates already adopted or generally as proposed by the investor-owned utilities in various pending proceedings (with various assumed levels of residential time-of-use adoption), based either on adopted or investor-owned utility-proposed time-of-use periods, all of which have two seasons (summer and winter). Two additional scenarios (5 and 6) examined more advanced rates designed to remedy grid conditions with high renewables penetration.

The work plan called for two independent analyses of time-of-use load impacts, both of which are available in the *2015 Integrated Energy Policy* electricity demand forecast docket.

- Investor-owned utilities were asked to analyze Scenarios 1-3 for both residential and nonresidential customers. Christensen Associates conducted this study.
- The Energy Commission analyzed Scenarios 1-6 for residential customers only. MRW & Associates conducted this study for the Energy Commission.

Interest in time-of-use periods and rates focuses on the spring in hopes that new rate designs can help address operational concerns embodied in the California Independent System Operator's "duck curve," a graphical depiction of the net load curve. There is also more uncertainty surrounding spring time-of-use load impacts than for the summer, for which there are many studies. A broad literature review attempted to locate studies published since 2006, which were additionally relevant to California climates and included quantitative results. The 33 most relevant studies are summarized in the MRW & Associates report. Some generalized findings from these studies relevant to parameters in this supplemental analysis include the following:

- Time-of-use periods were generally broad, 6-8 hours, summer afternoons and into early evening; only two studies used 3-4 hour periods.
- Customer opt-in was far more common in pilots than opt-out, creating a self-selection bias.
- Many studies assess time-of-use residential impacts both with and without enabling devices. Greater reductions were achieved from customers with such devices.
- No studies addressed whether load shifting occurred immediately after the end of a peak time-of-use period.
- Summer peak demand impacts received most attention; only studies in Ontario, Canada, Pennsylvania, and California reported winter/nonsummer results. While not directly applicable to California due to climate and other differences, the Pennsylvania (PECO) study found statistically significant load shifting in the spring, at about half the magnitude of the summer load shifts. Spring load shifts were attributed to customers shifting major appliance usage earlier in the day, before the afternoon peak period.
- None considered three time-of-use rate periods.

The California Independent System Operator's analysis found that with the exception of July and August, on the weekends, supply surplus is expected to occur during "super off-peak" hours from 10:00 a.m. to 4:00 p.m., when solar generation is highest. Similarly, surplus conditions are expected during this same period on March and April weekdays, when weather is mild and air-conditioning use is at a minimum. Moreover, supply is projected to be generally plentiful starting at 9:00 p.m. through the next morning or afternoon, depending on the month.

Results between the two consultant studies are very consistent for Scenarios 1 through 3 and show that an increase in the default participation percentage (increasing from 10 percent under Scenario 1 to 30 percent under Scenario 3) triples the load reduction to about 250 megawatts by 2025. These savings can increase by another 60 megawatts when combined with either targeted marketing or enabling technology. Scenario 4, analyzed under one study, shows that the load reduction can more than double to 650 megawatts if participation increases from 30 percent (under Scenario 3, high adoption opt-in) to 80 percent (under Scenario 4, default). Enabling technology provides another 150 megawatts of load reduction.

Similar findings of increased load reduction up to 1,500 megawatts are based on an 80 percent default participation rate under Scenario 5 versus 30 percent under Scenario 6. Savings increase another 300 megawatts with enabling technology.

The potential to increase load during periods of plentiful renewable generation and low load during spring was also studied under Scenarios 5 and 6. The savings at most are 60 megawatts during the week and 150 megawatts during the weekend by 2025. Given the limited literature on load increase potential, more aggressive assumptions show a higher estimate of 330 megawatts of load increase during the weekend. These estimates should not be taken as "bookends," due to the extremely limited experimental data on spring season price response.

Based on these two independent analyses, the Joint Staff Steering Committee draws the following high-level conclusions:

- More research and experience with residential time-of-use in California are needed to understand the load impacts of default time-of-use with sufficient certainty to incorporate them into Energy Commission demand forecasts.
- Peak-load impacts of shifting summer on-peak time-of-use periods to later in the day are potentially significant and should be considered in the investor-owned utilities' rate design proceedings or a new time-of-use period rulemaking.
- Springtime super off-peak load impacts should be further researched through California-specific pilot studies to gather essential customer elasticity data lacking in the literature.
- More research and experience with mandatory time-of-use for small and medium commercial and industrial customers are needed to maximize potential load impacts. Experiments with alternative rate designs, targeted marketing and outreach, and/or enabling technology should be conducted through pilot studies.

CHAPTER 1: Introduction to the Joint Staff Report

A joint agency (California Public Utilities Commission [CPUC], California Energy Commission [Energy Commission], and California Independent System Operator [California ISO])) staff proposal to conduct a supplemental rate analysis in the *2015 Integrated Energy Policy Report* (*IEPR*) proceeding was initiated in late 2014.

The analysis examined potential electric load impacts of possible changes to time varying rates and other rate design elements. Dimensions the analysis included possible changes to (a) residential fixed charges and TOU rate design and adoption rates, (b) TOU periods for residential and nonresidential rates classes, (c) transition to mandatory TOU and default critical peak pricing for small nonresidential customers. In addition, the analysis examined how conceptual changes to residential TOU rate design could address grid needs associated with higher levels of renewables.

The work plan for the joint agency supplemental rate analysis defined six rate scenarios, provided in Appendix A. Scenarios 1-4 consider rates already adopted or generally as proposed by the investor-owned utilities (IOUs) in various pending proceedings[1] (with various assumed levels of residential time-of-use (TOU) adoption), based either on adopted or IOU-proposed TOU periods, all of which have two seasons (summer and winter). Two additional scenarios (5 and 6) examined more advanced rates designed to address grid conditions with high renewables penetration.

In November 2014, California ISO staff initiated an analysis of hourly net loads to design new TOU periods that better align with changing operational needs due to increased penetration of renewable generation. During this analysis, California ISO staff posed and addressed a critical question: *How can TOU rate and loads with the right characteristic be used to manage California's RPS?"*

California ISO staff identified the following goal for TOU rate design: *TOU rates should be to smooth and flatten the net load curve by season.[2] This can be done by:*

- Shifting peak-load demand.
- Providing incentives for load to consume during low demand periods to minimize overgeneration.
- Reducing the need for flexible capacity resources, for example, reduce the magnitude of upward and downward ramps through managed load response.

Based on this analysis of operational needs, in March 2015, California ISO staff released its recommended TOU periods for further study. These TOU periods feature four seasons (winter,

1 R.12-06-013; A.13-12-015; A.14-01-027; A.14-11-014. In some cases, gaps in the IOU's proposed TOU period definitions were filled for this analysis.

2 CPUC staff developed its conceptual rates to inform these California ISO objectives. It should be noted, however, that the CPUC may establish other goals for TOU rates, if and when they are considered in a formal proceeding.

spring, outer summer [May June, September, October], and inner summer [July, August, September]). While the California ISO staff-proposed TOU period design also features up to four pricing periods (super-off-peak, off-peak, peak, and super-peak), no proposed season includes more than three pricing periods. These season and period definitions are presented in Chapter 4.

In April 2015, CPUC staff presented conceptual TOU rates designed to conform to the March 2015 recommended TOU period definitions. These rates assume a fixed customer charge[3] and are designed for a 2021 test year. Final rates were provided to Energy Commission staff in June 2015 for use in planning as Scenarios 5 and 6, for analysis of potential load impacts of TOU rates.

The work plan called for two independent analyses of TOU load impacts:

- The IOUs were asked to analyze Scenarios 1-3 for both residential and nonresidential customers.
- The Energy Commission was asked to analyze Scenarios 1-6 for residential customers only.[4]

These load impact analyses were performed by consultants (Christensen Associates, for the IOUs, and MRW, Inc., for the Energy Commission). The resulting reports are docketed in the *2015 IEPR* proceeding.

Much of California ISO's interest in TOU load impacts focuses on the spring, in the hope that TOU rates can help address operational concerns embodied in the "duck curve." However, as discussed in both consultants' load impact reports, there is more uncertainty concerning spring TOU rate load impacts than for the summer (which has been the subject of many more studies). Therefore, it is difficult to forecast, with any precision, the impact of TOU rates in the spring. This report finds that seasonal TOU load impacts in California, especially for seasons other than summer, can be assessed definitively only by piloting appropriately defined TOU rates.

In July 2015, CPUC D.15-07-001 directed the IOUs (subject to certain legislative conditions being met) to implement default residential TOU rates in 2019. Implementation of D.15-07-001 is underway, including two working groups charged with (a) TOU pilot development and (b) marketing, education, and outreach. The TOU Working Group is developing both opt-in and

3 This does not imply an endorsement of fixed customer charges by the CPUC, Energy Commission, or California ISO. Rather, the joint agency assumptions for all scenarios in the supplemental rate analysis include a $10 per month fixed charge (the maximum allowable under Assembly Bill 327 [Perea, Electricity: Natural Gas, Rates, and Net Energy Metering, Chapter 611, Statutes of 2013, (AB 327]) to take the most conservative view of potential load impacts.

4 These tasks overlap for residential customers, for Scenarios 1-3. Scenarios 1-4 reflect IOU existing or proposed rates, which apply to both residential and nonresidential customers. Scenarios 5 and 6 apply to residential customers only; development of nonresidential TOU rates for the California ISO "high renewables" TOU periods was deemed beyond the scope of this project due to time and resource limitations.

default pilots, including one or more "advanced" TOU rate designs similar to the more advanced rates examined in this report.[5]

Policy Context for Time-Varying Rates

The *Energy Action Plan II (EAP II)*[6] identifies demand response (DR) as among the state's "preferred means of meeting growing energy needs."[7] In 2003, the CPUC articulated a DR vision statement in which it said that electric customers should have "the ability to increase the value derived from their electricity expenditures by choosing to adjust usage in response to price signals" as customers are equipped with advanced meters.[8] *EAP II* concludes that "[w]ith the implementation of well-designed dynamic pricing tariffs and demand response programs for all customer classes, California can lower consumer costs and increase electricity system reliability."[9]

In CPUC D.08-07-045, the CPUC continued implementing its policy to "make dynamic pricing available for all customers" and affirmed its view that dynamic rates "can lower costs, improve system reliability, cut greenhouse gas emissions, and support modernization of the electric grid."[10]

Implementation of the CPUC's vision in D.08-07-045 has met with limited success. Thus, the Energy Commission's *2013 IEPR* stated:

> Large commercial and industrial investor-owned utility (IOU) customers … are on a default critical peak price, but most have opted out. Small commercial customers are now [beginning to see] time-of-use prices. For residential customers, these rates are optional and largely undersubscribed."[11]

While all three large IOUs offer residential TOU rates, they are not always designed to be understandable and attractive. Furthermore, utilities have not aggressively publicized or promoted participation in these rates. One barrier to widespread use of price-related DR has been the complexity of the TOU rates, which often combine 4 usage blocks with 3 (summer) TOU periods, resulting in a customer facing 12 possible prices for a kilowatt-hour (kWh) of energy consumption.

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5 An Assigned Commissioner's Ruling (ACR) dated September 24, 2015, in the CPUC's Residential Rate Reform proceeding (R.12-06-013) directed the IOUs "to prepare a menu of a minimum of three opt-in TOU rate designs for piloting beginning in 2016. At least one of the opt-in TOU pilot rates for each utility must be a TOU option with a more complex combination of seasons and periods than traditional TOU rates that better matches system needs."

6 California Energy Commission and California Public Utilities Commission, *Energy Action Plan II*, September 21, 2005. http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF

7 *EAP II*, p. 2.

8 *California Demand Response: A Vision for the Future* (2002 – 2007).

9 Ibid., p. 4.

10 D.08-07-045 at 4.

11 Energy Commission *2013 IEPR*, p.63

With the enactment of AB 327, the CPUC's ongoing rate design rulemaking (R.12-06-013) passed a major decision (D.15-07-001) to remove this barrier. In addition to implementing default TOU rates in 2019, D.15-07-001 directs the utilities (among other directives):

- To reduce the number of tiers in their default residential rates for 2015 through 2018.
- To offer optional (opt-in) TOU rates with no more than two tiers.
- To propose means to increase the participation of residential ratepayers in voluntary, opt-in TOU rates, specifically targeted to the period 2015–2018.
- To offer a variety of opt-in TOU pilots in 2016 and 2017 and default TOU pilots in 2018.
- To propose how best to integrate TOU rate programs with residential energy efficiency programs and other price-based and nonprice-based DR programs, including cost-effective enabling technology, to encourage maximum voluntary residential participation.12

While nearly all California IOU ratepayers now have TOU-capable meters, and most nonresidential customers are now on recently-mandated time-variant rates, fewer than 3 percent of residential ratepayers are on time-varying rates.

Residential TOU rates are not new; they have been adopted widely on a voluntary basis by two Arizona utilities serving Phoenix and are being tested by the Sacramento Municipal Utility District (SMUD). Mandatory TOU has recently been adopted in Ontario (Canada) and in parts of Italy, and optional TOU has been studied, as voluntary pilot projects, in many domestic and foreign locations. With respect to participation in voluntary TOU programs, the California IOUs lag far behind their Arizona counterparts, which have achieved participation rates of 25 percent to 50 percent, and SMUD, which has 16 percent to 18 percent participation in its opt-in TOU pilot.

While AB 327 prohibits implementation of default residential time-variant rates before 2018, D.15-07-001 authorizes multiple opt-in TOU pilot programs for the 2016 – 2017 transition years to comply with Senate Bill 1090 (Fuller, Electricity, Rates, Default Time-of-Use Pricing, Chapter 625, Statutes of 2014)[13] and prepare for residential default TOU anticipated in 2019. As discussed later in this report, these pilots present an opportunity to further understand reliable load impacts from TOU rates.

12 Many studies have shown that the effects of price-based DR are amplified by the introduction of enabling technologies, such as programmable communicating thermostats. For example, see: Brattle Group, 2012. "Meta-Analysis of Dynamic Pricing Studies- Some Initial Findings," by Ahmad Faruqui, Sanem Sergici, and Eric Shultz.

13 Public Utilities Code Section 745(d) requires that, before requiring or authorizing the IOUs to employ default TOU rates for residential customers, the CPUC must "explicitly considered evidence addressing the extent to which hardship will be caused on either of the following: (1) customers located in hot, inland areas, assuming no changes in overall usage by those customers during peak periods; (2) residential customers living in areas with hot summer weather, as a result of seasonal bill volatility, assuming no change in summertime usage or in usage during peak periods.

Other Relevant TOU Rate Programs

In support of the supplemental rate analysis project, MRW & Associates, LLC (MRW) examined the available literature on the effect of residential TOU rate designs on load and applied the demand elasticities[14] observed in the literature to model the impact of several TOU rate design scenarios on residential demand and energy usage.

Three criteria guided the search for appropriate studies: 1) published since 2006; 2) were relevant to California climates; and 3) included quantitative results. The literature search found that load impacts of residential time-of-use rates have been extensively investigated; there are scores of academic and conference papers analyzing nearly as many pilots. Even so, differing variables often make direct comparisons difficult. To reach a sufficiently robust number of studies, one very relevant but slightly older study, some metastudies, international studies, and critical peak pricing pilot studies were added to the list. With a total of 48 studies identified and reviewed, MRW summarized and assessed the 33 most relevant studies applicable to the TOU modeling work done for the Joint Agency *IEPR* supplemental rate analysis.

Despite this broad search, few studies provided useful estimations of elasticity to use in the California TOU rate impact modeling. Several studies that included recent statistics on electric demand-related TOU were inapplicable to California because of climate and demographic differences from California that could bias the seasonal impacts observed. Only 12 addressed residential rate impacts on usage patterns, either as an elasticity measurement or estimated percentage change. Nine of these provided data from specific pilot studies, two of which were California-specific, one from Arizona, and the remaining from the Northeast. Some generalized findings from these studies relevant to parameters in this supplemental analysis include the following:

- TOU periods were generally broad, 6-8 hours, summer afternoons and into early evening; only two studies used 3-4 hour periods
- Customer opt-in was far more common in pilots than opt-out, creating a self-selection bias.
- Many studies assess TOU residential impacts both with and without enabling devices. Greater reductions were achieved from customers with such devices.
- No studies addressed whether load shifting occurred immediately after the end of a peak TOU period.
- Summer peak demand impacts received most attention; only studies in Ontario, Canada, Pennsylvania, and California reported winter/nonsummer results. While not directly applicable to California due to climate and other differences, the Pennsylvania (PECO) study found statistically significant load shifting in the spring, at about half the

[14] Demand elasticity is a measure of how much the quantity demanded will change is another factor changes. One example is price elasticity of demand; this measures how the quantity demanded changes with price.

magnitude of the summer load shifts. Spring load shifts were attributed to customers shifting major appliance usage earlier in the day, before the afternoon peak period.

- None considered three TOU rate periods.

Three studies that provided the most relevant data for the Joint Agency Steering Committee (JASC) analytical project will be discussed in more detail.

Although among the older of the studies reviewed, Charles River Associates' *Impact Evaluation of the California Stateside Pricing Pilot,*[15] which ran from July 2003 to December 2004, proved to be the only comprehensive study of California to date and the most relevant to California's climate and customers. MRW, therefore, chose to use their daily and substitution elasticity inputs and methodology for assessing impacts on residential demand.

SMUD's *SmartPricing Options Final Evaluation,*[16] prepared in 2014, looks at a multi-year pricing pilot that tested three time-variant pricing plans, both opt-in and default enrollments, and the offer of an in-home display for opt-in customer recruitment. This study results are most applicable to California's inland areas.

An Arizona study[17] with peak loads driven by air conditioning is another study potentially applicable to inland California areas, although the Salt River Project pilot was targeted at higher electricity users.

15 MRW, Appendix A: Literature Review, Citation 6.

16 MRW, Appendix A: Literature Review, Citation 29.

17 MRW, Appendix A: Literature Review, Citation 25.

CHAPTER 2: Current and IOU-Proposed TOU Rates

Pacific Gas and Electric

Pacific Gas and Electric Company (PG&E) has two TOU rates open to residential customers, three TOU rates open to commercial and industrial (C&I) customers, and three TOU rates open to agricultural and pumping (A&P) customers. Residential schedule E-6 is a "tiered TOU" rate with three periods in the summer with a weekday peak of 1:00 p.m. – 7:00 p.m., and no peak in the winter. Residential schedule "EV" is restricted to those customers with electric vehicles and has the same three periods year-round. It has a weekday peak of 2:00 – 9:00 p.m. and a weekend/holiday peak of 3:00 p.m. – 7:00 p.m. The C&I and A&P rate schedules all have a summer weekday peak of 12:00 p.m. – 6:00 p.m., and no peak in the winter.

In accordance with CPUC decision D.15-07-001, as modified by D.15-11-013, schedule E-6 will close to new customers on or before June 1, 2016. PG&E plans to replace E-6 with E-TOU, a nontiered TOU rate for residential customers. According to the settlement agreement adopted in D.15-11-013, E-TOU-A will initially have a year-round weekday peak of 3:00 p.m. – 8 p.m., transitioning to a peak of 4:00 – 9:00 p.m. by January 1, 2020. E-TOU-B will have a year-round weekday peak of 4:00 – 9 p.m.

Southern California Edison

Southern California Edison Company (SCE) has four TOU rates open to residential customers, seven TOU rates open to C&I customers, and four TOU rates open to A&P customers. SCE's TOU rates vary widely in terms of the rate design features: tiered versus nontiered, number of periods, peak definition, and availability of a super off-peak (SOP) period.

Generally, SCE's nontiered TOU rates without a SOP period have a summer weekday peak of 12:00 p.m.–6:00 p.m. The exception is SCE's newest TOU rate, schedule TOU-D, which has a year-round weekday peak of 2:00 p.m. – 8:00 p.m. SCE's TOU rates with a SOP period have a summer weekday peak of 1:00 p.m. – 5:00 p.m. and a SOP of 12:00 a.m. – 6:00 a.m. SCE's four EV schedules have three peak definitions (weekdays 12:00 p.m. – 6:00 p.m., 10:00 a.m. – 6:00 p.m. and 12:00 p.m. – 9:00 a.m.) to stimulate electric vehicle (EV) charging. SCE does not have any pending TOU rates before the CPUC.

San Diego Gas & Electric

San Diego Gas & Electric Company (SDG&E) has five TOU rates open to residential customers, six TOU rates open to C&I customers, and three TOU rates open to A&P customers. SDG&E has two residential schedules with a summer weekday peak of 11:00 a.m. – 6:00 p.m. and two residential EV schedules with the same year-round SOP of 12:00 a.m. – 5:00 a.m., but different year-round peaks (12:00 p.m. – 6:00 p.m. vs. 12:00 p.m. – 8 p.m.). The last residential schedule has two periods year-round: a weekday peak of 12:00 p.m. – 6:00 p.m. and all other hours off-peak. The C&I and A&P rate schedules all have three periods year-round with a summer weekday peak of 11:00 a.m. – 6:00 p.m. and a winter peak of 5:00 p.m. – 8:00 p.m.

SDG&E's request in its most recent rate design window (RDW) application (A. 14-01-027) to change the peak definition on all TOU schedules to 2:00 p.m. – 9:00 p.m. on summer weekdays, 5:00 p.m. – 9:00 p.m. on winter weekdays, and a year-round SOP of 12:00 a.m. – 6:00 a.m. was denied without prejudice, in D.15-08-040. SDG&E may refile its proposal in its current general rate case (GRC) Phase 2 proceeding, A.15-04-012. D. 15-07-001 authorized SDG&E to offer two experimental residential TOU rates, each with three periods but with different summer weekday peak definitions. One would have a summer weekday peak of 2:00 p.m. – 6:00 p.m., and the other would have a summer weekday peak of 5:00 p.m. – 9:00 p.m.

CHAPTER 3: Analysis of Current and IOU-Proposed TOU Rates

This supplemental analysis examines potential TOU load impacts beyond what is already included in the Energy Commission's base demand forecast. The Energy Commission's demand forecast incorporates data from the latest research on TOU load impacts, as submitted in the IOUs' April 1 DR load impact reports submitted to the CPUC's resource adequacy and Long-Term Procurement Plan (LTPP) proceedings. In this report, load impacts are assumed to be incremental to historical consumption in the Energy Commission's baseline forecasts. No additional growth in TOU participation is forecasted in this analysis beyond what is assumed in the IOU's April 1 demand response reports.

Baseline Projections (IOU April 1 Load Impact Reports)

The IOUs' April 1, 2015 report forecasts incremental TOU load impacts, almost exclusively from small and medium-sized commercial customers transitioning onto mandatory TOU. One exception is PG&E, which included a small (6 megawatt [MW]) load impact from residential customers on opt-in TOU rates (of which, 2 MW is incremental to 2015). SCE and SDG&E forecasted no incremental load impacts from residential TOU.

Table 1 shows the projected incremental TOU impacts from the April 2015 IOU filings by utility, sector, and weather condition. These estimates are used to calculate the baseline DR for the *2015 IEPR* forecast. Since the *2015 IEPR* forecast includes historical peak demand through 2015, the numbers in **Table 1** must be transformed to be incremental to 2015, as historical TOU impacts are captured in the historical loads. The resulting impacts are shown in **Table 2**.

Table 1: 2025 TOU Incremental Peak (MW) Load Impacts in the Revised Base *2015 IEPR* Forecast*

	Residential	Non-Residential	Total
1:2 (System RA Forecast)			
PG&E	6	26	32
SCE		21	21
SDG&E		11	11
Statewide	6	58	64
1:10 (Local RA Forecast)			
PG&E	7	29	36
SCE		22	22
SDG&E		12	12
Statewide	7	63	70

Source: IOU DR Load Impacts Reports, filed April 1, 2015.

Table 2: 2025 TOU Incremental Peak (MW) Load Impacts in the Revised Base *2015 IEPR* Forecast* (Incremental to 2015)

	Residential	Nonresidential	Total
1:2 (System RA Forecast)			
PG&E	2	16	18
SCE		0	0
SDG&E		11	11
Statewide	2	27	29
1:10 (Local RA Forecast)			
PG&E	2	17	19
SCE		0	0
SDG&E		12	12
Statewide	2	29	31

Source: IOU DR Load Impacts Reports, filed April 1, 2015.

Christensen Analysis of Scenarios 1 – 3

On January 21, 2015, the CPUC's Energy Division requested that the IOUs' Demand Response Measurement and Evaluation Committee provide additional load impact scenarios beyond those submitted in the IOUs' April load impact report filings. On March 20, 2015, the Energy Division further clarified the request by specifying that the IOUs should estimate residential and nonresidential load impacts for Scenarios 1 – 3. (See Appendix A.) The IOUs subsequently retained Christensen Associates to complete the requested scenario analysis.

Christensen's Residential Assumptions and Method

Christensen Associates Energy Consulting ("Christensen") produced a study, dated November 15, 2015, titled, *Statewide Time-of-Use Scenario Modeling for 2015 California Energy Commission Integrated Energy Policy Report*. This study documents the potential load impacts from offering new TOU rates for residential and nonresidential customers in California and considers a range of scenarios regarding the design and market participation of the new TOU rates at the three California IOUs. Also included are alternative scenarios regarding retention rates for nonresidential default critical-peak pricing (CPP)[18] after expiration of customers' bill protection period.

Moreover, the report provides simulated load impacts for 2016 through 2025, where results are based on (1) customer class-level reference load data, (2) TOU rate designs, (3) assumptions regarding customer price responsiveness, and (4) different trajectories of customer participation over time. In doing so, this study simulates the potential percentage and cumulative load impacts at each utility, and statewide, under alternative scenarios of TOU rate

[18] Critical peak pricing is a rate designed to to reward participating customers for reducing electricity use, or shifting use to off-peak hours.

design (for example, different price structures and the peak period occurring later in the day) and opt-in participation rates.

The Christensen study method simulates load impacts of TOU rates using three sets of data plus an analytical tool or model:

- Hourly load data for a base period for relevant groups of customers
- TOU rate designs and participation rates
- Assumptions on how participating consumers respond to TOU rates.

The analytical tool (that manipulates the load data and applies the customer response information to relevant TOU periods) implements a version of the constant elasticity of substitution (CES) demand model (used to model functional economic relationships), which is applied separately to each day of the year, using the applicable rates, pricing periods, and reference loads for the day.

The most directly relevant source of TOU demand response information for this study is the Statewide Pricing Pilot (SPP) because of the direct relevance to the Christensen study and the fact that the SPP quantified the difference in demand response across the widely varying climate zones in California. Christensen used results from the CPP-F portion of the pilot, focusing on normal (non-CPP) weekdays, in which a TOU rate applied. The relevance of the SPP outweighs the fact that it is somewhat dated (2005).

TOU Rate Assumptions: *S*cenario 1 rates reflect existing TOU periods and rates, while removing the pricing tiers. The TOU rates proposed by the utilities for Scenarios 2 and 3 for this study are generally characterized by peak, part-peak, and off-peak prices. Each utility proposes to move the peak period to later in the evening than is the case in the current rates. Different rates are designed for Californians for Affordable and Reliable Energy (CARE) and non-CARE customers. **Table 3** summarizes the rate designs.

Table 3: Residential Scenario 1 – 3 TOU Rate Designs

Season	Pricing Period	Scenario 1 Non-CARE	Scenario 1 CARE	Scenario 2 & 3 Non-CARE	Scenario 2 & 3 CARE
PG&E					
Summer	Off-peak	$ 0.181	$ 0.100	$ 0.207	$ 0.141
	Partial-peak	$ 0.258	$ 0.163		
	Peak	$ 0.373	$ 0.259	$ 0.310	$ 0.212
Winter	Off-peak	$ 0.176	$ 0.099	$ 0.156	$ 0.107
	Peak/Partial-peak	$ 0.192	$ 0.113	$ 0.175	$ 0.120
SCE					
Summer	Super Off-peak	$ 0.113	$ 0.073	$ 0.113	$ 0.073
	Off-peak	$ 0.198	$ 0.142	$ 0.198	$ 0.142
	Peak	$ 0.366	$ 0.263	$ 0.366	$ 0.263
Winter	Super Off-peak	$ 0.113	$ 0.073	$ 0.113	$ 0.073
	Off-peak	$ 0.159	$ 0.114	$ 0.159	$ 0.114
	Peak	$ 0.265	$ 0.190	$ 0.265	$ 0.190
SDG&E					
Summer	Off-peak	$ 0.210	$ 0.119	$ 0.173	$ 0.096
	Semi-peak	$ 0.252	$ 0.153	$ 0.229	$ 0.141
	Peak	$ 0.311	$ 0.200	$ 0.266	$ 0.170
Winter	Off-peak	$ 0.211	$ 0.126	$ 0.176	$ 0.105
	Semi-peak	$ 0.232	$ 0.143	$ 0.194	$ 0.119
	Peak	$ 0.247	$ 0.155	$ 0.211	$ 0.133

Source: Christensen Report, November 15, 2015, Table 2.1.

Christensen Results: Residential Scenarios 1 – 3 Load Impacts

Table 4 presents results of the TOU load impact simulations, where the results represent the **average** peak period reduction across nonholiday weekdays. Peak hour reductions are 40 percent to 50 percent higher than the average peak period reductions reported below.[19] The first two columns indicate season and pricing period. The results are presented in three sets of columns. The first two show TOU demand response in percentage terms, for non-CARE and CARE customers, respectively. These percentages apply to TOU participants only. The class-level percentage load changes are much smaller and vary by year as the assumed enrollment rate increases. The final set shows implied combined load changes for the final year of analysis (2025) after applying the percentage changes to the number of participating customers, according to the relevant assumed participation rate at the end of the period. The three columns in each set report results for each of the three scenarios. In all columns, negative signs indicate load *reductions*. The bold values within the groups of rows for each utility indicate average hourly results for the summer peak period.

19 Average hourly impacts could be increased by 17 percent to 48 percent via targeted marketing of TOU rate in hotter areas (Christensen report, p.28).

Table 4: Residential Scenario 1 – 3 TOU Load Impacts: Percentage and Combined (MW) Changes

Season	Pricing Period	Non-CARE Percentage Impact Scen. 1	Non-CARE Percentage Impact Scen. 2	Non-CARE Percentage Impact Scen. 3	CARE Percentage Impact Scen. 1	CARE Percentage Impact Scen. 2	CARE Percentage Impact Scen. 3	Total Aggregate Impact (MW) - 2025 Scen. 1	Total Aggregate Impact (MW) - 2025 Scen. 2	Total Aggregate Impact (MW) - 2025 Scen. 3
PG&E										
Summer	Off-peak	1.1%	-0.3%	-0.3%	0.8%	-0.1%	-0.1%	3.1	-0.9	-2.6
	Partial-peak	-1.3%	n/a	n/a	-0.8%	n/a	n/a	-4.8	n/a	n/a
	Peak	**-3.7%**	**-3.0%**	**-3.0%**	**-2.4%**	**-1.5%**	**-1.5%**	**-16.0**	**-16.2**	**-48.7**
	Summer total	-0.6%	-0.9%	-0.9%	-0.3%	-0.4%	-0.4%	-3.3	-4.1	-12.2
Winter	Off-peak	0.4%	0.4%	0.4%	0.3%	0.2%	0.2%	1.3	1.1	3.3
	Peak/Partial-peak	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.6	0.3	1.0
	Winter total	0.4%	0.3%	0.3%	0.3%	0.2%	0.2%	1.2	0.9	2.8
SCE										
Summer	Super Off-peak	4.3%	4.3%	4.3%	2.5%	2.5%	2.5%	13.0	13.0	38.9
	Off-peak	-0.9%	-0.9%	-0.9%	-0.6%	-0.6%	-0.6%	-3.6	-3.6	-10.9
	Peak	**-6.3%**	**-6.3%**	**-6.3%**	**-3.4%**	**-3.4%**	**-3.4%**	**-32.3**	**-32.3**	**-96.8**
	Summer total	-0.1%	-0.1%	-0.1%	0.0%	0.0%	0.0%	-3.9	-3.9	-11.6
Winter	Super Off-peak	1.2%	1.2%	1.2%	0.7%	0.7%	0.7%	3.1	3.1	9.4
	Off-peak	0.2%	0.2%	0.2%	0.0%	0.0%	0.0%	0.4	0.4	1.3
	Peak	-1.3%	-1.3%	-1.3%	-0.7%	-0.7%	-0.7%	-4.5	-4.5	-13.5
	Winter total	0.2%	0.2%	0.2%	0.1%	0.1%	0.1%	0.3	0.3	1.0
SDG&E										
Summer	Off-peak	1.0%	1.7%	1.7%	0.7%	1.2%	1.2%	0.8	1.3	3.9
	Semi-peak	-0.4%	-0.5%	-0.5%	-0.2%	-0.3%	-0.3%	-0.4	-0.4	-1.1
	Peak	**-2.0%**	**-1.6%**	**-1.6%**	**-1.2%**	**-1.0%**	**-1.0%**	**-1.7**	**-1.7**	**-5.2**
	Summer total	-0.4%	-0.2%	-0.2%	-0.2%	-0.1%	-0.1%	-0.4	-0.3	-1.0
Winter	Off-peak	0.2%	0.4%	0.4%	0.1%	0.3%	0.3%	0.2	0.3	1.0
	Semi-peak	0.0%	0.2%	0.2%	0.0%	0.1%	0.1%	0.0	0.1	0.4
	Peak	-0.2%	-0.1%	-0.1%	-0.1%	-0.1%	-0.1%	-0.2	-0.1	-0.2
	Winter total	0.1%	0.2%	0.2%	0.0%	0.1%	0.1%	0.0	0.1	0.4

Source: Christensen Report, November 15, 2015, Table 4.2.

Targeted Marketing Sensitivity

Christensen also studied a sensitivity case in which the utilities target marketing of TOU rates in hotter climate zones that contain (on average) more responsive customers. They assumed an extreme case in which all opt-in TOU customers come from the hottest (and most demand responsive) climate zones. **Table 5** provides the approximate percentage increases in load impacts due to target marketing, relative to the base case. Christensen qualifies these results, noting that these results likely overstate the realistic effects of targeted marketing, because it assumes the utilities are able to focus all TOU enrollments in the climate zones that are expected to have the highest TOU demand response.

Table 5: Targeted Marketing Sensitivity Case: Residential Scenarios 1 – 3

Utility	Scenario 1	Scenario 2	Scenario 3
PG&E	48%	41%	41%
SCE	17%	17%	17%
SDG&E	26%	25%	25%

Source: Christensen Report, November 15, 2015, p.28.

Christensen Nonresidential Load Impacts

Background

While large C&I customers (200 kW and above) have been on time-differentiated rates (TOU and/or combined TOU/CPP rates, with demand charges) for nearly a decade, until recently most small and medium C&I customers were on flat (non-time-differentiated) rates, possibly including a demand charge. Small and medium C&I customers began transitioning to TOU rates in 2012 (for PG&E) and 2014 (for SCE). SDG&E will begin the transition in November 2015. As the transition is not yet complete, there are, as yet, limited data available to assess the responses of those customers to TOU pricing.

Scenarios 2 – 4[20] include two elements that affect load impacts from nonresidential TOU and/or combined TOU/CPP programs:

- The change in the definition of the TOU peak period, which the authors assume coincides with the event-day critical pricing period
- Low and high assumed levels of participation for customers defaulted to CPP.

The most recent DR load impact studies contained a complete *ex-ante* forecast of DR load impacts for each utility, including TOU and CPP. Christensen based the scenario analyses on these studies, using per-customer reference loads and load impacts by size group (less than 20 kW, 20 to 200 kW, and more than 200 kW) for each peak month day (peak day of individual months) of the years 2016 through 2025.

TOU Load Impacts for Small and Medium C&I Customers

Christensen reports the following results:

For Small C&I Customers (under 20 kW):

- For SCE, TOU load impacts of 2 percent to 4 percent were observed in all hours.
- For PG&E, TOU load impacts of 1.5 percent to 3.5 percent were observed in all hours.
- SCE load impacts were not materially different than PG&E load impacts, in spite of SCE's much larger peak to off-peak price differential (price ratios 2.93 (SCE) vs 1.17 [PG&E])

20 Scenario 1 "status quo" did not consider any changes to existing TOU periods; Scenarios 5 and 6 did not include nonresidential rates.

For Medium C&I Customers (20 to 200 kW):

- For SCE, TOU load impacts of 0 percent to 1 percent were observed in all hours, with a peak-hour impact of 0.4 percent.
- For PG&E, TOU load impacts of 2 percent to 3 percent were observed in all hours, with a peak-hour impact of 2.1 percent.
- SCE load impacts were less than PG&E load impacts, in spite of SCE's much larger peak to off-peak price differential (price ratios 2.13 (SCE) vs 1.22 [PG&E])

In summary, Christensen concludes that

> "…customers have not responded in a manner consistent with economic price theory (i.e., reducing usage in newly higher-price peak hours). Rather, customers appear to respond by conserving in roughly equal percentages across the pricing periods, perhaps reflecting increased energy awareness due to participation in the transition process."

However, notwithstanding this analysis, Christensen forecast *ex ante* load impacts of 20 to 25 MW each, for PG&E and SCE, from small and medium C&I TOU rates in load impact evaluations conducted for those utilities.[21]

TOU Load Impacts for Large C&I Customers:

As Christensen states,

> "these [large] customers have been on TOU rates for many years, so their TOU demand response is "embedded" in the Utility's load profile. However, one might expect the load profile for these customers to change after their rate structure [definition of TOU periods] is modified."

To estimate the effects of changing TOU period definitions, Christensen performed both a data analysis (SDG&E data) and a series of simulations based on assumed elasticity values.

Based on the simulations, Christensen estimated load *increases* of 3.7percent (SCE and PG&E) and 3.0 percent (SDG&E), for the early afternoon hours that are proposed to shift out of the peak period. Correspondingly, Christensen estimated load *decreases* of 3.8 percent (SCE), 2.8 percent (PG&E), and 3.1 percent (SDG&E) for the later evening hours that are proposed to be newly included as peak hours. However, Christensen issues caveats for these results as follows:

> The CES model used to conduct the simulations produced results (based on assumptions about customer price-driven behavior) that appear to exaggerate some of the load impacts. Specifically, the load increases that occur in the middle of the day may not be likely to occur (or persist) in exactly that way (we might expect some smoothing of the load changes). The 3 to 4 percent simulated

21 *2014 Load Impact Evaluation of Southern California Edison's Mandatory Time-of-Use Rates for Small and Medium-Sized Business and Agricultural Customers: Ex-post and Ex-ante Report*, Hansen and Patton, April 2015, p.39.

load changes that occur in the re-classified on-peak hours may prove to be large compared to real-world experience.[22]

CPP Assumptions for C&I Customers:

Load impacts for C&I customers on CPP[23] for the proposed peak-period definition were simulated by shifting the *ex-ante* percentage load impacts for the current event window to coincide with the forecast event window. The *level* of the load impacts will change with the (presumably lower) load levels during the later event window. The mapping of percentage load impacts was carried out using the following assumptions.

For Small C&I Customers (Under 20 kW):

- For PG&E and SCE, load impacts were assumed to be 2 percent during event hours and 0 elsewhere.
- For SDG&E, the authors assumed no load impacts from these customers, which is consistent with its findings and assumptions to date.

For Medium C&I Customers (20 to 200 kW):

- For PG&E and SCE, load impacts were assumed to be 1.5 percent during event hours and zero elsewhere.
- For SDG&E, the load impact percentage is based on a 2.5 percent "base" value that is adjusted downward due to customer awareness assumptions. This results in load impacts of roughly 2.2 percent in later years.
- Christensen issues caveats for these load impact assumptions as follows:
- "For small and medium customers, we lack robust empirical data about how they respond to default CPP. Around 170,000 SMB [small and medium business] customers were defaulted onto CPP in November 2014 at PG&E, but those customers have yet to experience any CPP events. SCE and SDG&E small and medium customers have yet to be defaulted onto CPP. Therefore, default CPP ex-post impact estimates are not available."[24]

CPP event hours were assumed to be the following:

- PG&E: Scenario 1 = 2 to 6:00 p.m.; Scenarios 2 and 3 = 4:00 p.m. to 9:00 p.m.
- SCE: Scenario 1 = 2 to 6:00 p.m.; Scenarios 2 and 3 = 2:00 p.m. to 8 p.m.
- SDG&E: Scenario 1 = 11:00 a.m. to 6:00 p.m.; Scenarios 2 and 3 = 2:00 p.m. to 9:00 p.m.

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22 Christensen Report, November 15, 2015, pp. 40-41.

23 Large C&I customers were defaulted to CPP beginning in 2009; more than half have opted out to a non-CPP TOU rate (with demand charges). Small and medium C&I customers are in the early stages of being defaulted to combined CPP/TOU rates; most of these customers are now on a transitional TOU-only rate. In Scenario 2 (low enrollment), 25 percent of small and medium C&I customers defaulted to CPP are assumed to remain on that rate after their bill protection expires; For Scenario 3 (high enrollment), the corresponding assumption is 75 percent.

24 Christensen Report, November 15, 2015, p.42.

CPP Load Impacts Results for C&I Customers

Christensen estimates total C&I CPP impacts of about 100 MW (PG&E), 50 to 65 MW (SCE), and 30 MW (SDG&E) for the high enrollment Scenario 3. Results for Scenario 2 were about 70 MW, 25 to 30 MW, and 25 MW, for PG&E, SCE, and SDG&E, respectively. Scenario 1 results were similar to Scenario 2 results, but slightly higher[25]. In each case, the load impacts represent a 1-in-2 utility August peak day. According to Christensen's report:

> The results for the 3 IOUs show that load impacts are lower in Scenario 2 than Scenario 1. Despite the fact that the enrollment and event-hour percentage load impacts are held constant, the shift to a later event window reduced the load impacts because overall load levels were lower during that time. SDG&E's CPP load impacts are largely from the large C&I customers, the enrollment for which remains constant across scenarios. The load impacts for the medium C&I customers vary with enrollments, but are small in comparison to the large C&I load impacts.[26]

CPP load impacts and enrollments, excluding the large C&I (more than 200 kW) customers for Scenario 3, are estimated to be about 35 MW (PG&E), 35 to 45 MW (SCE), and 8 to 9 MW (SDG&E). These estimates are highly sensitive to enrollment assumptions and are reduced by one-half to two-thirds under Scenarios 1 and 2.[27]

MRW Analysis of Residential Load Impact Scenarios

The MRW study, *Potential Load Impacts of Residential Time of Use Rates in California*, focused not only how much TOU rates could decrease load and consumption during peak-demand hours, but also if TOU rates could induce additional consumption during times that the California ISO is predicting that California might experience overgeneration events: spring afternoons when solar is producing significant amounts of power and spring runoff that requires hydroelectric facilities to operate.

MRW modeled six TOU rate scenarios for each of the three major California IOUs, consistent with the joint staff-specified scenarios provided in Appendix A. The six scenarios assumed differing by TOU periods, rates, and customer participation (opt-in versus opt-out). Four scenarios used current an IOU proposed rates and TOU periods. Two additional cases investigated what would happen if periods that reflect the California ISO's four-season TOU periods and large price differentials were instituted. All the scenarios relied upon the price elasticity values coming out of the California Statewide Pricing Pilot, which were found to be generally consistent with the literature.

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25 Figures 7.1 to 7.3 from the Christensen Report. Scenarios 1 and 2 assume the same enrollment levels but different CPP event hours.

26 Christensen Report, November 15, 2015, p.44.

27 Figures 7.4 to 7.6 from the Christensen Report.

In addition to base cases, MRW also modeled an "Expected+ Case" for each of the six scenarios. The Expected + case used the same basic elasticity inputs but with modifications to simulate the use of enabling technologies (for example, devices that help users shift their usage). **Table 6** summarizes the approach.

Table 6: MRW Assumptions: Base Case vs. Expected+

Assumption	Base Case	Expected+
Technology	No Enabling Technology	30% of Participants Use Enabling Technology
Customer Response		100% Greater Than Base Case for Those Using Enabling Technology

Source: MRW Report, October 16, 2015, Table 3, p.15.

The modeling suggests that the current and proposed time-of-use rates can induce modest peak reductions on the order of 100 MW to 800 MW for the three major IOUs. Key factors that contribute to the range are assumed participation rates (80 percent for an opt-out program, 10 to 30 percent for an opt-in one) and, to a lesser degree, the penetration and use of enabling technologies (that is, devices that help users to shift their usage). The modest results are partly due to the rates not having large TOU period price differentials and partly due to the TOU periods not lining up with the peak demand period (early evening).

With more aggressive scenarios using the California ISO-defined TOU periods, the magnitude of the load decrease during the peak hours is more pronounced. At the 7:00 p.m. peak, the TOU rates would decrease the peak demand by 1,400 MW, 125 percent greater than the impact with the same participation rate (80 percent), but the more standard TOU rate design.

The impact of the TOU rates on the spring daylight hours was also of interest. As should be expected, because the current and proposed IOU rates are not designed to induce additional consumption in key hours, the scenarios using them showed only minimal to counterproductive results. The scenarios with the California ISO-designed rate periods and more pronounced rate differentials still had only modest impacts on usage during the spring, increasing the low springtime weekday usage by only about 60 MW. This is attributable primarily to the small substitution elasticity of demand (-0.012). For experimentation, when an aggressive substitution elasticity (-0.066) is applied[28], the projected impact more than triples to more than 200 MW.

Because no existing pilot or study is directly applicable to the analysis here, the modeled impacts must be seen as indicative of the possible load responses rather than predictive. Additional pilots designed to specifically investigate California residential responses to particular rate designs are needed. Even so, the modeling performed suggests:

28 This "aggressive" elasticity value is more consistent with the spring season PECO results and is still much lower than summer elasticities found for PG&E, SMUD, and the Salt River Project. Neither the 60 MW nor the 200 MW spring impact estimates should be taken as definitive "bookends," pending an actual trial (pilot) in California of rates designed specifically to induce customers to shift load to super-off-peak periods in the spring.

- Conventional residential TOU rate designs, such as those in place and those proposed, can reduce summer peak demands on the order of hundreds of MWs. But to get more than about 100 MW reduction, high customer participation is required, such as from having the TOU rates be default.
- The current and proposed TOU rates will likely induce little to no additional use during spring afternoons when the California ISO predicts possible overgeneration events.
- When hypothetical rates designed to align with the California ISO's load profile and with very aggressive TOU price differentials, the modeling suggests much greater peak load impacts could occur, on the order of 1,000 MW to 1,500 MW.
- Even with aggressive rate design in targeted TOU periods, only modest increases in residential loads during periods where overgeneration is being predicted should be expected, given current knowledge. This result is very uncertain, however, as consumer response to rates designed to induce usage has not been explicitly investigated, and thus further research is suggested, including pilots of rates specifically designed to increase usage during periods of expected surplus renewable energy.

CHAPTER 4: California ISO's Needs Analysis and TOU Period Design

Scenarios 5 and 6 are based on conceptual TOU periods developed by the California ISO to match future grid conditions reflecting significant renewable penetration. Given the trend of renewable development in California, California ISO developed these periods to maximize the integration of renewable resources to maintain reliable operation of the grid. In a departure from most TOU rates that encourage peak reductions, Scenarios 5 and 6 explored the possibility of boost consumer *consumption* (or shift consumption from peak periods) when generation is plentiful.

California ISO's Analysis of "High Renewables" Grid Needs

California ISO's analysis began with historical data from 2013 and 2014 to study identified trends in renewable generation compared to electric demand on the system. The California ISO also gathered data from the CPUC's 2024 LTPP proceeding and 2021 wind and solar projections, as well as demand forecasts for 2021 and 2024 produced by the Energy Commission. From these data, the California ISO created projections of future load curves in 2021 of anticipated electricity needs and net load curves, calculated by subtracting solar and wind output from the overall demand. The California ISO then created time blocks comparing the load to the 5-minute distribution of net load.

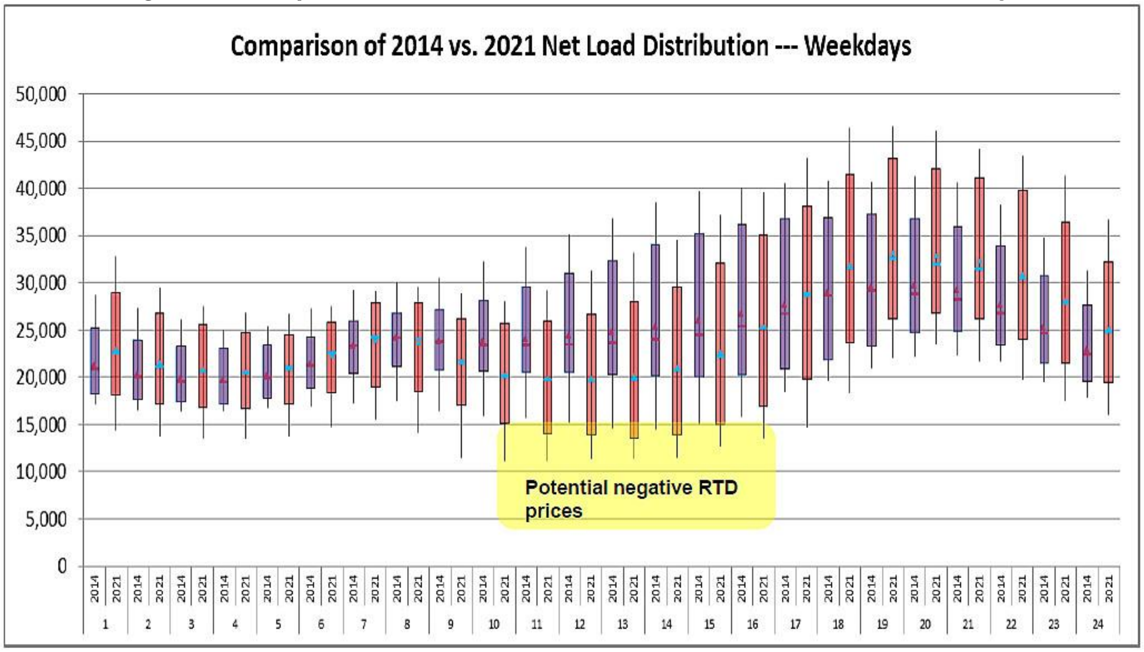
The analysis produced several interesting conclusions. First, California ISO's coincident peak demand varies by season, is generally coincident with the three IOUs during spring, fall, and winter, and is one hour ahead of PGE's during the summer. However, significant renewable penetration, especially from solar, shifts the summer coincident net load peak from 4:00 p.m. – 5:00 p.m. to 6:00 p.m. – 7:00 p.m. The California ISO also observed that demand was particularly high during summer weekdays in July and August, creating "super peaks."

On the other hand, plentiful renewable resources also mean that energy production can outpace demand during certain times of the day. In the absence of significant storage capabilities, the surplus energy (both renewable and conventional) may be curtailed.

The California ISO's analysis found that with the exception of July and August, on the weekends, supply surplus is expected to occur during "super off-peak" hours from 10:00 a.m. to 4:00 p.m. when solar generation is highest. Similarly, surplus conditions are expected during this same period on March and April weekdays, when the weather is mild and air conditioning use is at a minimum. Furthermore, supply is projected to be generally plentiful starting at 9:00 p.m. through the next morning or afternoon, depending on the month.

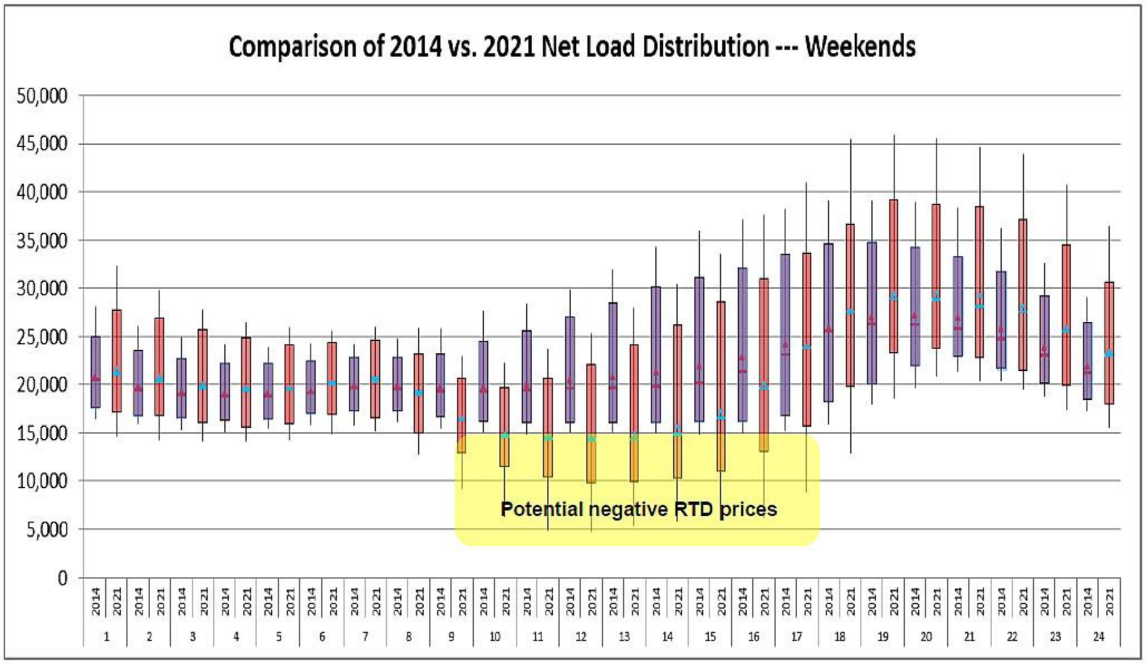
Figure 1 and **Figure 2** show the hourly net load distribution for 2014 and 2021. The colored bars represent 95 percent of the net load distribution in each hour. The top of each vertical line shows the hourly maximum, and the bottom shows the minimum net load for that hour. The minimum net load reflects a level of generation that must be maintained for reliability and may result in negative wholesale prices during the mid-day (for example, from 10:00 a.m. to 4:00 p.m.).

Figure 1: Comparison of 2014 vs. 2021 Net Load Distribution: Weekdays



Source: California ISO, "CAISO's TOU period analysis to address 'High Renewable' grid needs," March 12, 2015. Available at http://www.caiso.com/Documents/CalifornialSO_Time_UsePeriodAnalysis.pdf.

Figure 2: Comparison of 2014 vs. 2021 Net Load Distribution: Weekends



Source: ***California ISO, CAISO's TOU period analysis to address 'High Renewable' grid needs*****, March 12, 2015. Available at: http://www.caiso.com/Documents/CalifornialSO_Time_UsePeriodAnalysis.pdf.**

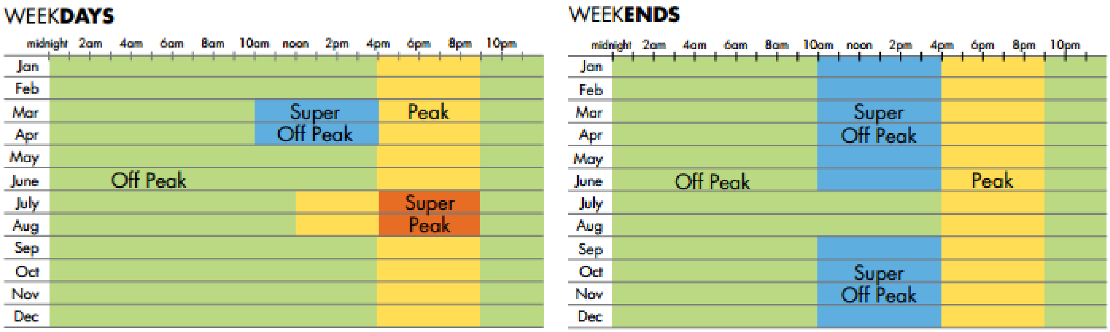
California ISO's observed patterns in the data resulted in the recommended price periods for weekdays and weekends reflected in the conceptual rates provided by CPUC staff for Scenarios 5 and 6 (described further below).

California ISO's Proposed "High Renewables" TOU Periods

Based on the analysis, California ISO established a maximum of three time blocks per day tailored to seasons and the higher use patterns on weekdays versus weekends (**Figure 3**). Furthermore, the TOU periods also reflect the system needs when generation is constrained during the late afternoon/early evening peak and plentiful at midday. The periods were designed to reduce peak load or shift that demand to nonpeak periods. Importantly, the rate periods were designed to stimulate load to consume during low-demand periods to minimize overgeneration. Collectively, reducing the peak demand and increasing off-peak consumption may lessen the need for flexible capacity resources used during the steep ramping period in the late afternoon to meet peak demand.[29]

29 See also California ISO's "Duck Chart" explaining the impact of renewables on grid operations.at http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf.

Figure 3: California ISO Proposed TOU Periods



Source: California ISO, *Matching Time-of-Use Rate Periods with Grid Conditions Maximizes Use of Renewable Resources*, June 11, 2015. Available at: http://www.caiso.com/Documents/MatchingTimeOfUsePeriodsWithGridConditions-FastFacts.pdf.

As discussed below, CPUC staff provided reasonably aggressive, revenue-neutral,[30] rates for each period designed to encourage conservation or consumption, as appropriate.

30 CPUC staff's conceptual Scenario 5 and 6 TOU rates are revenue-neutral to a projected flat rate for each IOU, on an annual basis, but not revenue-neutral by season.

CHAPTER 5: CPUC Staff-Developed Conceptual TOU Rates for Scenarios 5 and 6

CPUC staff developed conceptual TOU rates for scenarios 5 and 6 using a two-stage process. First, economic principles were applied to produce uncapped rates (Stage 1), for example, the so-called "science" of rate design. Second, a cap was placed on selected rates to yield potentially "acceptable" rates from a customer perspective (Stage 2), for example, the so-called "art" of rate design.

The two stages are described as follows:

Stage 1: TOU Rate Construction

CPUC staff developed a rate model built up from the following components:

- Transmission Rate
- Other Nonbypassable Costs (NBCs)
- Marginal Energy Cost (MEC)
- Marginal Generation Capacity Cost (MGCC)
- Marginal Distribution Capacity Cost (MDCC)
- Other (remaining rate components not included above)

The assumed cost allocation of each rate component is set forth in Table 1 of Appendix C. Further detail on model input assumptions is provided in Table C-2 of Appendix C. The rates were designed to be revenue-neutral with standard residential rates expected in 2021.

CPUC staff followed the following six-step process for deriving fully time-differentiated TOU rates:

- Use preliminary calculations of fixed charge and volumetric revenues for 2021 (CARE and non-CARE).
- Compute sales by TOU period.31
- Compute time-differentiated generation marginal costs (energy and capacity) by TOU period.
- Time-differentiate the marginal distribution (MDCC) rate component.
- Compute factors for EPMC allocation of "Other" costs.
- Compute "Blended" allocation of "Other" costs; compute uncapped TOU rates.

31 Provided by Christensen Associates.

Stage 2: Capped Rates

Modeling the rate allocations in the manner described above sometimes produced rates in which both the super-off-peak and the super-peak rates appeared to CPUC staff to be too high[32]; and the allocation methods do not allow both to be reduced simultaneously. For the super-off peak periods, CPUC staff found it desirable for the rate to be as low as possible (to maximize demand response); therefore, the rate was subjected to a "floor" consisting of the sum of the transmission rate, the NBCs, and the super-off-peak period average MEC. CPUC staff also found it desirable that the super-off-peak rate be designed to collect some distribution costs.[33] Super-off-peak rates resulting from the above method were often higher than necessary under that criterion, in CPUC staff's opinion; therefore, a 7.5 cents/kWh price cap (or floor, in certain cases) was established.

For the July-August "Inner Summer" period, the outcome yielded super-peak rates that (in CPUC staff's judgment) appeared likely to be unacceptable to customers. Therefore, a price cap was also applied to the super-peak period. That rate was set to exceed the sum of the transmission rate, the NBCs, the MGCC, the super-peak period average MEC, and the MDCC, or roughly 60 cents per kWh.[34] The model computes the revenue shortfall produced by capping the super-off-peak and super-peak rates and reallocates the shortfall equally to all units of demand (equal cents per kWh) in the remaining TOU periods.[35] The outcome of capping produces TOU rates that, in CPUC staff's opinion, are shaped generally according to economic principles (that is, they are reasonably cost-based) and may be acceptable to customers if properly accompanied by customer education and outreach and/or enabling technologies.

This process produced results, such as the rates provide in **Figure 4** and **Figure 5** (using PG&E as an example). A complete set of Scenario 5 and 6 rate results for PG&E, SCE, and SDG&E is provided in Appendix B.

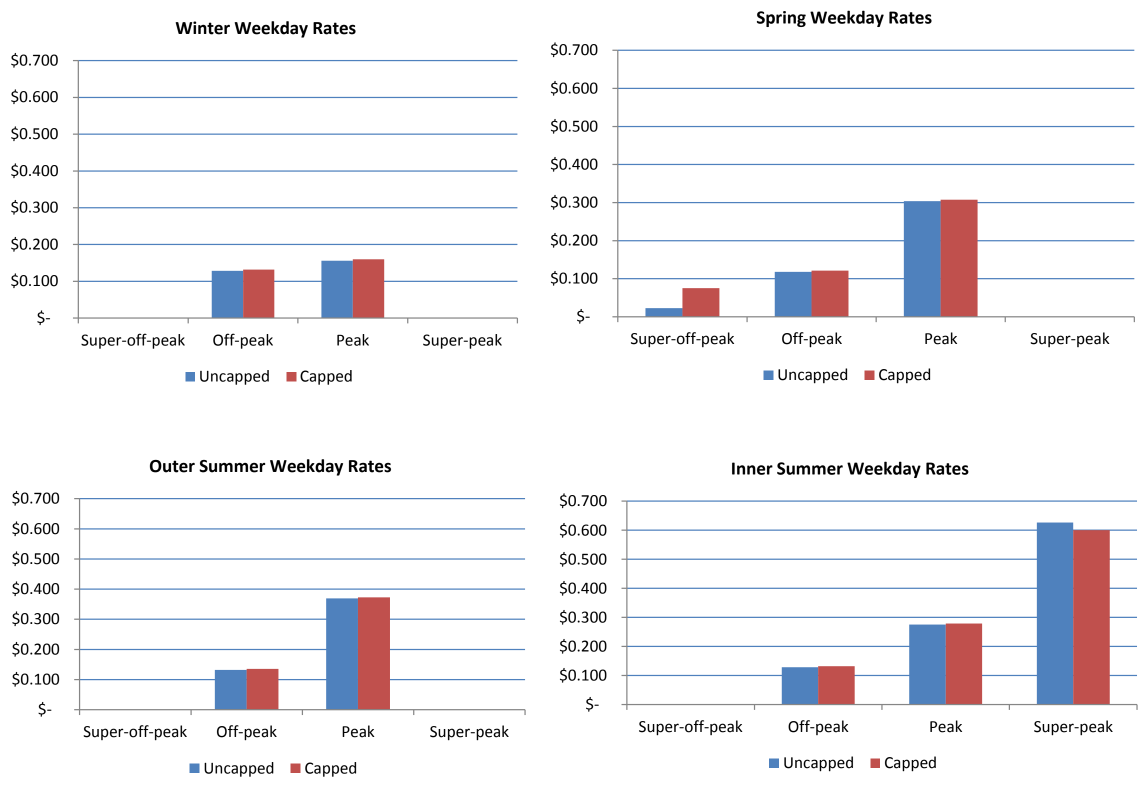
32 In the case of super-peak rates, CPUC staff believes that the uncapped rate is too high from a customer acceptance perspective; in the case of super-off-peak rates, CPUC staff believes that the uncapped weekend super-off-peak rates were too high above the marginal cost and NBC floor price from an economic efficiency perspective. In the case of the spring weekday super-off-peak rate, CPUC staff increased the uncapped price to equate it with the assumed weekend super-off-peak rate.

33 For the 2021 data, the lowest CPUC staff-suggested super-off-peak rate cap is about 7.5 cents per kWh. In most cases, the uncapped super-off-peak rates are higher. However, in the spring weekday super-off-peak TOU period, the uncapped rate is less than the cap. In this case the 7.5 cent "cap" actually acts as a floor in the model. The result in CPUC staff's model is that all super-off-peak rates are set at 7.5 cents.

34 See, for example, the discussion of floor prices in D.07-09-016. For the 2021 data, the lowest suggested super-peak rate cap is about 60 cents per kWh.

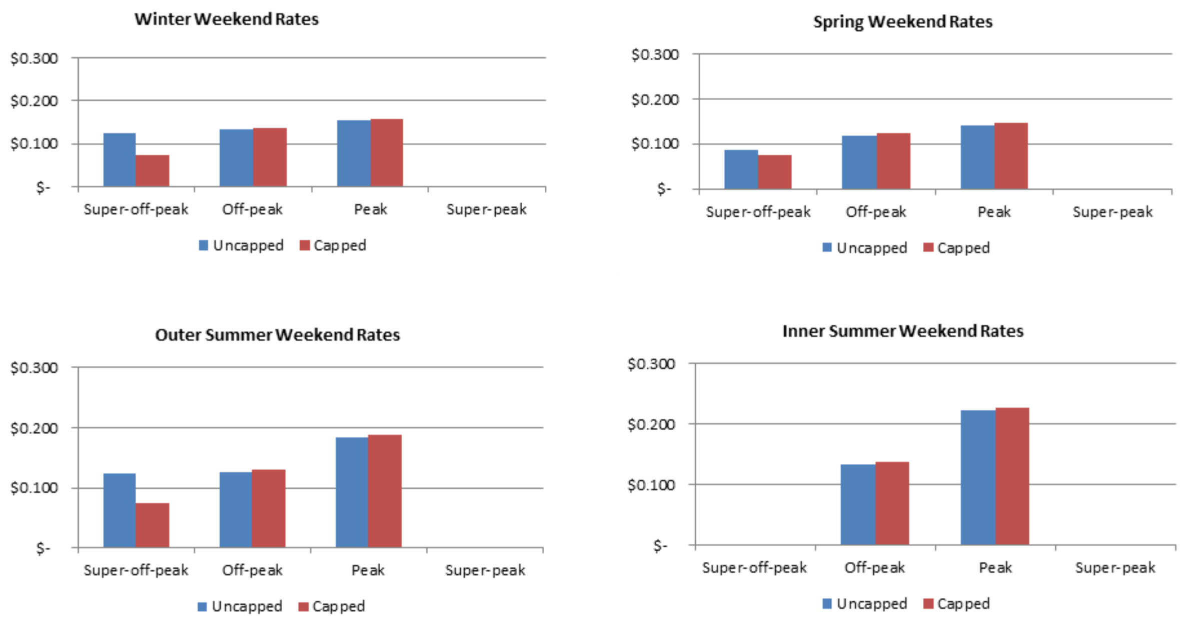
35 Since the reallocated rate component was small (on the order of 1 cent per kWh), it was not deemed necessary to do a more complex (for example, proportional) reallocation.

Figure 4: Weekday Conceptual TOU Rates for Scenarios 5 and 6: PG&E Example ($/kWh)



Source: CPUC staff, June 2015.

Figure 5: Weekend Conceptual TOU Rates for Scenarios 5 and 6: PG&E Example ($/kWh)



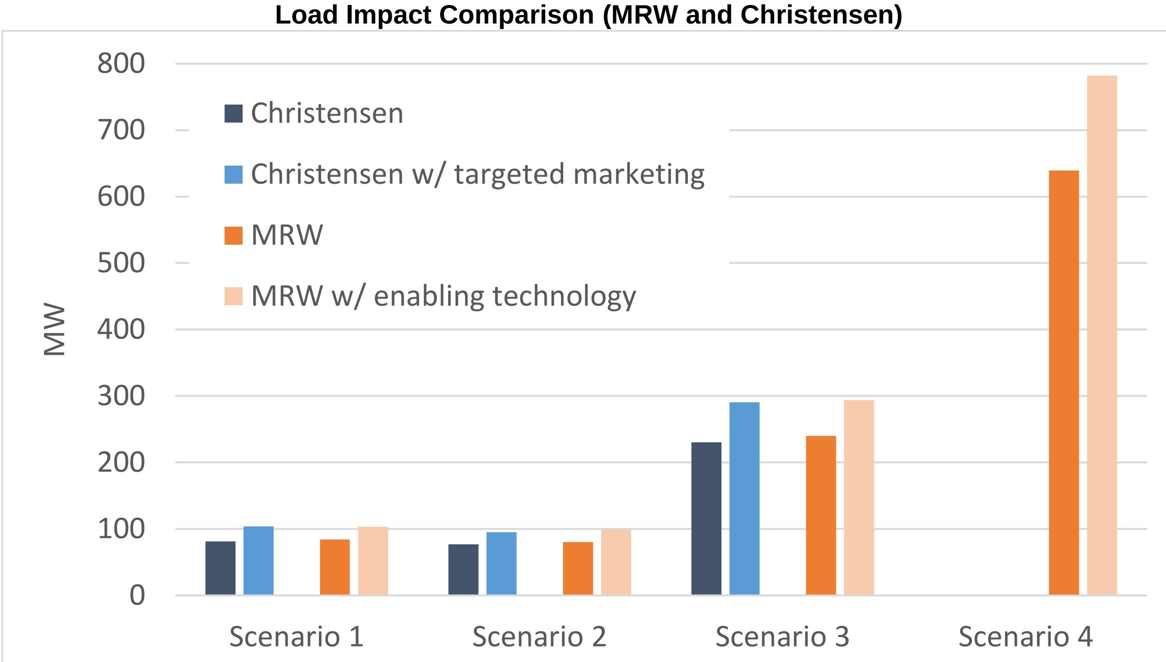
Source: CPUC staff, June 2015.

CHAPTER 6:
Conclusions and Recommendations

Conclusions

Taken from the two studies, **Figure 6** shows the combined peak-hour load reductions for all three utilities under Scenarios 1 through 4. Results between the studies are very consistent for Scenarios 1 through 3 and show that an increase in the default participation percentage (increasing from 10 percent under Scenario 1 to 30 percent under Scenario 3) triples the load reduction to about 250 MW by 2025. These savings can increase by another 60 MW when combined with either targeted marketing or enabling technology. Scenario 4, analyzed under one study, shows that the load reduction can more than double to 650 MW if participation increases from 30 percent (under Scenario 3, high adoption opt-in) to 80 percent (under Scenario 4, default). Enabling technology provides another 150 MW of load reduction.

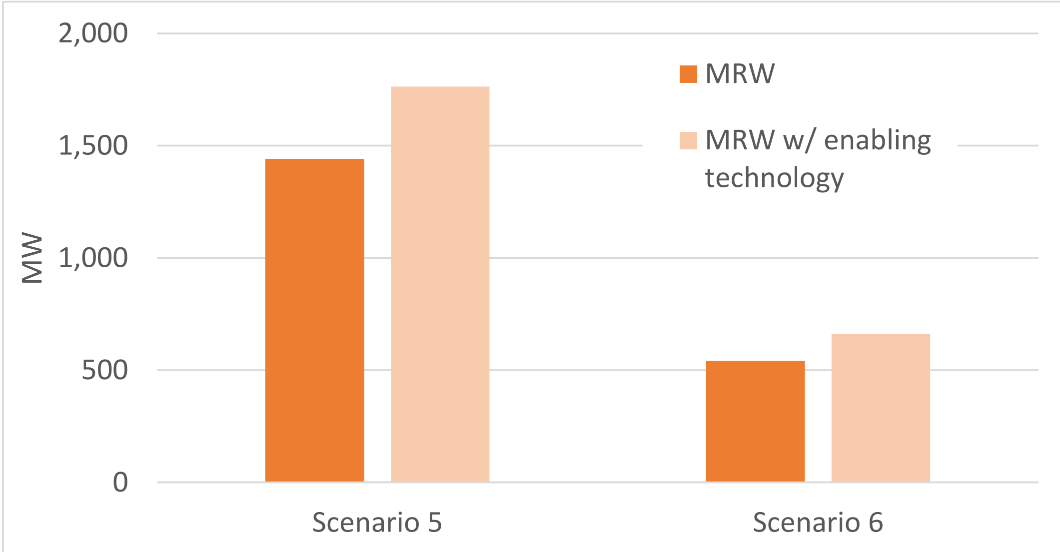
Figure 6: Residential Scenarios 1-4: Summer Peak Load Impact Comparison (MRW and Christensen)



Source: Christensen Report Table 4.2 for peak-hour load impact for scenarios 1 - 3. Christensen peak-hour load impact with targeted marketing based on the ratio of average peak period impact with targeted marketing (shown in Christensen Report Figures 4.8 – 4.10) to average peak period impact (shown in Christensen Report Table 4.2) multiplied by the peak hour load impact (also from Christensen Report Table 4,2). MRW Report Table 15.

Figure 7 shows similar findings of increased load reduction up to 1,500 MW based on an 80 percent default participation rate under Scenario 5 versus a 30 percent under Scenario 6. Savings increase another 300 MW with enabling technology.

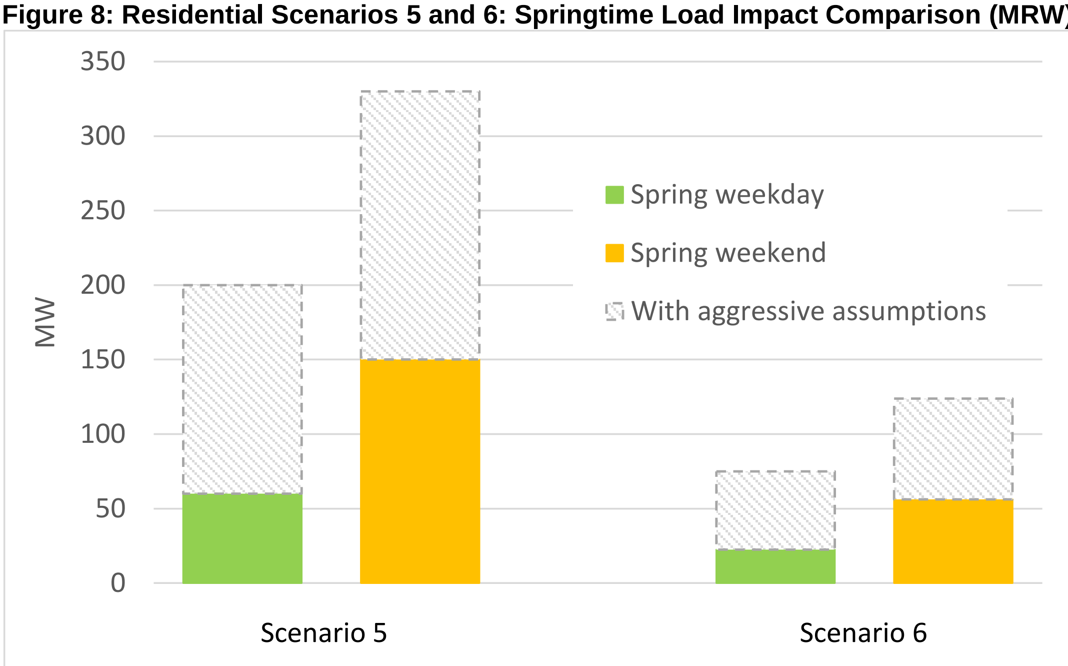
Figure 7: Residential Scenarios 5 and 6: Summer Peak Load Impact Comparison (MRW)



Source: MRW Report Table 16.

The potential to increase load during periods of plentiful renewable generation and low load during spring was also studied under Scenarios 5 and 6. **Figure 8** found the savings to be at most 60 MW during the week and 150 MW during the weekend by 2025. Given the limited literature on load increase potential, more aggressive assumptions show a higher estimate of 330 MW of load increase during the weekend. These estimates should not be taken as "bookends," due to the extremely limited experimental data on spring season price response.

Figure 8: Residential Scenarios 5 and 6: Springtime Load Impact Comparison (MRW)



Source: MRW Report Table 14.

Recommendations

Joint staff observes a number of high-level conclusions from this analysis that have implications for future studies or regulatory proceedings.

- More research and experience with residential TOU in California are needed to understand potential load impacts of default TOU with sufficient certainty to incorporate them into the Energy Commission's demand forecast. Statewide load impacts of TOU, regardless of season or time of day, depend greatly on assumptions about enrollment strategy (default vs. opt-in), adoption of enabling technology, marketing strategy, and customer response (demand elasticity). In the next full *IEPR* cycle, the Energy Commission's consideration of whether to include the potential impact of default residential TOU in 2019 (as directed in D.15-07-001) will be informed by the research produced out of the TOU pilots in R.12-06-013.
- Peak-load impacts of shifting summer on-peak TOU periods to later in the day ("late-shift" TOU) are potentially significant and should be considered in the IOUs' rate design proceedings or a new TOU period rulemaking. California ISO staff proposed TOU periods (and CPUC staff applied conceptual rates to these periods) in an effort to craft a "best fit" rate design that could help address late-shift peak demand and growing overgeneration concerns anticipated in the near future. The rate design has two key features: (a) a springtime super off-peak rate and (b) a late-shifted summer super peak rate (coinciding with a late-shifted peak rate in all other months). The latter feature aligns with the general trajectory of late-shift peak rates proposed by SDG&E for all rate classes in its RDW case (A.14-01-027), which will soon be refiled in its GRC Phase 2 case (A.15-04-012); proposed by PG&E for all residential TOU rates in its RDW case (A.14-11-014); and already approved for one SCE optional residential TOU rate (D.14-12-048).
- CPUC Decision 15-08-040 rejected SDG&E's late-shift TOU proposal until further review in a successor proceeding, citing insufficient record on forecasted grid conditions to justify the change. SDG&E's proposal faced opposition from parties representing agriculture, schools, and the solar industry. CPUC Commissioners have discussed the possibility of opening a new rulemaking on TOU periods to treat the issue comprehensively for all IOUs. To the extent that the IOUs' proposals contribute, in part, to achieving the California ISO's proposed vision for TOU, the California ISO's participation in CPUC proceedings to further consider these proposals will be critical.
- Springtime super off-peak load impacts should be further researched through California-specific pilot studies to gather essential elasticity data lacking in the literature. While the "indicative" MRW results for springtime load increase under the California ISO-proposed rate periods were small, joint agency staff sees merit in further study of the potential to modify consumption behavior during periods of excess renewable supply. There is a clear gap in the literature with regard to springtime load shifting potential. To draw firm conclusions about the potential for rate design to contribute as a solution to renewables integration, California-specific pilots to better quantify springtime demand elasticity are needed.
- The CPUC's rate reform rulemaking (R.12-06-013) presents an opportunity to pilot such advanced rates in IOU service territories through the residential TOU pilots ordered in D.15-07-001 being conducted in Phase 3. The TOU working group in R.12-06-013 is developing a menu of potential default (or new opt-in) TOU rates that will be piloted during 2016 – 2017 in preparation for 2018 filings to propose default residential TOU effective 2019. An Assigned Commissioner Ruling in that proceeding directed the IOUs to pilot, at minimum, one opt-in TOU rate option with a "more complex combination of seasons and time periods than traditional TOU rates that better matches system needs." Joint staff recommends that one or more of the "advanced" TOU rate designs pilots

should incorporate the California ISO-proposed TOU periods or a variant that incorporates the essential features. In addition to the design of the TOU periods, it is critically important that the super-off-peak rate be low enough to capture the attention of customers. These pilots should also test the effect of new technologies (such as programmable thermostats, smart phone-based energy management apps, and/or direct load control devices) that could increase demand response and enhance customer awareness and acceptance of these advanced rate designs. The California ISO and Energy Commission should accompany the design and implementation of these pilots to ensure that they produce actionable results for future load forecasting and grid management.

- More research and experience with mandatory TOU (with, and without CPP) for small and medium C&I customers are needed to better understand and maximize potential load impacts. The IOUs should experiment with alternative rate designs, targeted marketing and outreach, and/or enabling technology through pilot studies or other methods to reach these customers and enhance demand response. While impacts of TOU and combined TOU/CPP programs on large C&I customers have been well studied, and are already incorporated into the *IEPR* forecasts, small and medium C&I customers have only very recently begun transitioning to mandatory TOU and default TOU/CPP programs. As a result, there are almost no data available as to how these customers will respond to these rates. Initial indications are that small and medium C&I customers newly transitioned to TOU are responding predominantly by conserving energy in all hours, rather than by shifting load out of the peak hours, as would be expected by economic theory. Initial *ex ante* load impact forecasts for small and medium C&I customers from TOU and CPP/TOU have been small.
- In future rate proceedings (GRC Phase 2 or Rate Design Window), the IOUs should propose new pilots and/or other strategies targeted at small and medium C&I customers. These efforts should test alternative TOU rate designs (for example, more aggressive price differentials), targeted marketing and outreach and/or enabling technologies to encourage demand response in this customer segment. Alternatively, the CPUC may wish to consider scoping this issue into a new or existing rulemaking.

ACRONYMS

Acronym	Definition
A&P	Agricultural and pumping
AB 327	Assembly Bill 327
ACR	Assigned Commissioner's Ruling
C&I	Commercial and industrial
California ISO	California Independent System Operator
CARE	Californians for Affordable and Reliable Energy
CES	Constant elasticity of substitution
Christensen	Christensen Associates Energy Consulting
CPP	Critical peak pricing
CPUC	California Public Utilities Commission
DR	Demand response
EAP II	*Energy Action Plan II*
Energy Commission	California Energy Commission
EPMC	Equal percent of marginal cost
GRC	General rate case
IEPR	*Integrated Energy Policy Report*
IOU	Investor-owned utility
kW	Kilowatt
kWh	Kilowatt-hour
LOLE	Loss of load energy
LTPP	Long-Term Procurement Planning proceeding
MCP	Market clearing price
MDCC	Marginal distribution capacity cost
MEC	Marginal electricity costs
MGCC	Marginal generation capacity cost
MRW	MRW & Associates, LLC
MW	Megawatt
NBC	Nonbypassable charges
PG&E	Pacific Gas and Electric Company
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SMUD	Sacramento Municipal Utilities District
SOP	Super off-peak
SPP	Statewide Pricing Pilot
TOU	Time-of-use

APPENDIX A: Supplemental TOU Scenarios Studied, Relative to *IEPR* Base Case Assumptions

Table A-1: Supplemental TOU Scenarios

	2015 IEPR Baseline	Supplemental Analysis: Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6
		Current TOU periods, 10% Res TOU Opt-in, Low CPP	Proposed TOU periods, 10% Res TOU opt-in, Low CPP	Proposed TOU periods, 30% Res TOU opt-in, High CPP	Proposed TOU periods, Res TOU default, High CPP	TOU period overhaul, Res TOU default	TOU period overhaul, 30% Res TOU opt-in
Residential							
Fixed Charge	None Assumed	$10/Month	$10/Month	$10/Month	$10/Month	$10/Month	$10/Month
TOU							
Participation Rate	~2% (no growth)	Ramp to 10% by 2025	Ramp to 10% by 2025	Ramp to 30% by 2025	Ramp to 80% by 2025	Ramp to 80% by 2025	Ramp to 30% by 2025
TOU Period							
PG&E	12 pm - 6 pm (current)	12 pm - 6 pm (current)	4 pm - 9pm (proposed)	4 pm - 9pm (proposed)	4 pm - 9pm (proposed)	ISO staff-recommended periods/ CPUC staff-provided conceptual rate design	
SCE	12 pm - 6 pm (current), 2 pm - 8pm (optional rate)	12 pm - 6 pm (current), 2 pm - 8pm (optional rate)	2 pm - 8pm (effective 2019)	2 pm - 8pm (effective 2019)	2 pm - 8pm (effective 2019)		
SDG&E	11 am - 6 pm (current) or 2 pm - 9pm (proposed)	11 am - 6 pm (current)	2 pm - 9pm (proposed)	2 pm - 9pm (proposed)	2 pm - 9pm (proposed)		
Non-Residential							
TOU Period					N/A	N/A	
PG&E	12 pm - 6 pm (current)	12 pm - 6 pm (current)	4 pm - 9pm (proposed for res.)	4 pm - 9pm (proposed for res.)			
SCE	12 pm - 6 pm (current)	12 pm - 6 pm (current), 2 pm - 8pm (optional rate)	2 pm - 8pm (effective 2019)	2 pm - 8pm (effective 2019)			
SDG&E	11 am - 6 pm (current) or 2 pm - 9pm (proposed)	11 am - 6 pm (current)	2 pm - 9pm (proposed)	2 pm - 9pm (proposed)			
CPP Participation	Varies by IOU	Low (as specified by IOU)	Low (as specified by IOU)	High (as specified by IOU)			

Notes: "Proposed" generally means as proposed by the IOUs in pending CPUC rate design cases

Source: Joint staff work product (CPUC, Energy Commission, and California ISO), March 2015.

APPENDIX B:
Scenarios 5 and 6 Conceptual TOU Rates for PG&E, SCE, and SDG&E

Table B-1: PG&E Conceptual Capped TOU Rates (For Scenarios 5 and 6)

Conceptual PG&E Non-CARE Rates per TOU Period (2021)

	Super Off-Pk	Off-Pk	Peak	Super Peak	Ratio (h/l)
Volumetric Charge ($/kWh)					
Weekday					
Winter		$0.132	$0.160		1.21
Spring	$0.075	$0.121	$0.307		4.09
Outer Summer		$0.136	$0.373		2.74
Inner Summer		$0.132	$0.279	$0.60	4.55
Weekend					
Winter	$0.075	$0.136	$0.159		2.12
Spring	$0.075	$0.123	$0.146		1.95
Outer Summer	$0.075	$0.130	$0.187		2.49
Inner Summer		$0.137	$0.226		1.65
Fixed Charge	$11.33	Per Month (in 2021)			

Conceptual PG&E CARE Rates per TOU Period (2021)

	Super Off-Pk	Off-Pk	Peak	Super Peak	Ratio (h/l)
Volumetric Charge ($/kWh)					
Weekday					
Winter		$0.089	$0.108		1.21
Spring	$0.051	$0.082	$0.207		4.06
Outer Summer		$0.092	$0.252		2.74
Inner Summer		$0.089	$0.188	$0.405	4.55
Weekend					
Winter	$0.051	$0.092	$0.107		2.10
Spring	$0.051	$0.083	$0.099		1.94
Outer Summer	$0.051	$0.088	$0.126		2.47
Inner Summer		$0.093	$0.153		1.65
Fixed Charge	$5.66	Per Month (in 2021)			

Source: CPUC staff, June 2015.

Table B-2 SCE Conceptual Capped TOU Rates (For Scenarios 5 and 6)

Conceptual SCE Non-CARE Rates per TOU Period (2021)					
	Super Off-Pk	Off-Pk	Peak	Super Peak	Ratio (h/l)
Volumetric Charge ($/kWh)					
Weekday					
Winter		$0.148	$0.177		1.20
Spring	$0.075	$0.138	$0.331		4.41
Outer Summer		$0.152	$0.399		2.63
Inner Summer		$0.148	$0.297	$0.60	4.05
Weekend					
Winter	$0.075	$0.152	$0.177		2.36
Spring	$0.075	$0.140	$0.162		2.16
Outer Summer	$0.075	$0.147	$0.207		2.76
Inner Summer		$0.155	$0.246		1.59
Fixed Charge	$11.33	Per Month (in 2021)			

Conceptual SCE CARE Rates per TOU Period (2021)					
	Super Off-Pk	Off-Pk	Peak	Super Peak	Ratio (h/l)
Volumetric Charge ($/kWh)					
Weekday					
Winter		$0.100	$0.119		1.19
Spring	$0.051	$0.093	$0.224		4.39
Outer Summer		$0.103	$0.270		2.62
Inner Summer		$0.100	$0.201	$0.405	4.05
Weekend					
Winter	$0.051	$0.103	$0.120		2.35
Spring	$0.051	$0.094	$0.110		2.16
Outer Summer	$0.051	$0.099	$0.140		2.75
Inner Summer		$0.105	$0.166		1.58
Fixed Charge	$5.66	Per Month (in 2021)			

Source: CPUC staff, June 2015.

Table B-3: SDG&E Conceptual Capped TOU Rates (for Scenarios 5 and 6)

Conceptual SDG&E Non-CARE Rates per TOU Period (2021)					
	Super Off-Pk	Off-Pk	Peak	Super Peak	Ratio (h/l)
Volumetric Charge ($/kWh)					
Weekday					
Winter		$0.228	$0.256		1.12
Spring	$0.075	$0.219	$0.353		4.71
Outer Summer		$0.228	$0.414		1.82
Inner Summer		$0.229	$0.348	$0.60	2.62
Weekend					
Winter	$0.075	$0.233	$0.257		3.43
Spring	$0.075	$0.221	$0.242		3.23
Outer Summer	$0.075	$0.227	$0.278		3.71
Inner Summer		$0.234	$0.316		1.35
Fixed Charge	$11.33	Per Month (in 2021)			

Conceptual SDG&E CARE Rates per TOU Period (2021)					
	Super Off-pk	Off-pk	Peak	Super Peak	Ratio (h/l)
Volumetric Charge ($/kWh)					
Weekday					
Winter		$0.154	$0.173		1.12
Spring	$0.051	$0.148	$0.238		4.67
Outer Summer		$0.154	$0.279		1.81
Inner Summer		$0.154	$0.235	$0.405	2.63
Weekend					
Winter	$0.051	$0.157	$0.173		3.39
Spring	$0.051	$0.149	$0.164		3.22
Outer Summer	$0.051	$0.153	$0.188		3.69
Inner Summer		$0.158	$0.213		1.35
Fixed Charge	$5.66	Per Month (in 2021)			

Source: CPUC staff, June 2015.

APPENDIX C: Rate Model Assumptions and Method for Scenario 5 and 6 Conceptual TOU Rates

Table C-1: Assumed Cost Allocation by Rate Component for Scenario 5 and 6 Conceptual TOU Rates

Rate Component	Assumed Allocation by TOU Period
Transmission Rate • Transmission rates are a pass through of Federal Energy Regulatory Commission regulated transmission rates and are not time-variant.	Flat
Other Nonbypassable Costs (NBCs) • As stated in D.07-09-016, NBCs cannot be discounted. The general interpretation is that this requires that NBCs cannot differ by time (for example, a lower NBC rate during off-peak periods)	Flat
Marginal Energy Cost (MEC) • California ISO staff provided a forecast of hourly MECs for 2024 and stated these would be reasonable for a 2021 forecast. CPUC staff selected the PG&E Bay Area zone and SCE territory as representative zones. These forecasts were then averaged by TOU period.	Averaged by TOU Period
Marginal Generation Capacity Cost (MGCC) • CPUC staff used SCE's proposed MGCC value of $120.40/year from its 2015 GRC Phase 2 (A.14-06-014) as the starting point for the MGCC rates for each IOU. This is the most recently filed proposal and reflects the full long-run marginal cost of generation capacity without adjustments for short term surplus. • CPUC staff used the Loss of Load Energy (LOLE) (or Loss of Load Probability) method of allocation, which is derived from probabilistic production simulation modeling which accounts for both loads and supply availability. In response to a CPUC data request, SCE provided its hourly relative LOLEs for 2017, which were then adjusted as described and combined by TOU period.[36]	By LOLE

36 The California ISO-proposed TOU periods to address "High Renewables" grid needs call for a super-on-peak period for July and August; assuming that the highest LOLE would occur in those months. However, in examining SCE's LOLE data, CPUC staff discovered that the hottest days for the historical year on which the loads were based occurred in early September. Because California ISO staff's recommended TOU periods separate July-August from May-June-September-October, an adjustment was made to smooth the LOLEs during the four summer months (June-September). CPUC staff assumes a reallocation of the total June-September weekday relative LOLE (96%) as follows: June- 19 percent; July- 29 percent; August- 29 percent; and September- 19 percent. This was followed by a second reallocation of 10 percent of the relative LOLE from the inner summer peak hours to the spring peak hours (based on a potential need for ramping capacity during those hours). The final allocations of MGCC are as follows: 5 percent each to March and April weekday peak hours; 19 percent each to the June and September peak hours, and 24 percent to the July-August super-peak hours. The assumed allocation of MGCC to the TOU periods is based on the LOLE's adjusted as described above. The result is that about 38 percent of the MGCC is allocated to the "outer summer" (May, June, September, and October) weekdays, 48 percent is allocated to the "inner summer" (July and August) weekdays, 10 percent to spring peak hours, and about 4 percent to summer weekends. No MGCC cost is allocated to the winter months.

Rate Component	Assumed Allocation by TOU Period
Marginal Distribution Capacity Cost[37] [38] (MDCC) • Distribution circuit data from SDG&E shows a strong tendency to peak during roughly the same summer afternoon and evening hours as the system load; however according to SDG&E, 17% of its distribution circuits are winter-peaking. SCE indicates that about 33% of its circuits are either winter- or night-time peaking. SCE's and PG&E's distribution circuits have similar distributions of peaking times. • To accommodate the diversity in distribution circuit peak times, CPUC staff assumed an allocation of MDCC as a blend (weighted average) of a flat distribution and a distribution based on adjusted LOLE (as used to allocate MGCC). Initially, CPUC staff assumed weights of 50% flat and 50% LOLE.	50% Flat; 50% by LOLE for PG&E; 60/40 for SCE 85/15 for SDG&E
Other (Remaining Rate Components) • The three marginal cost components (MEC, MGCC, MDCC), a transmission and NBCs comprise 65% to 75% of the total rate. The remaining 25-35% consists of marginal customer costs, which are non-time-varying, and non-marginal costs associated with recovery of past capital investments, fixed O&M and A&G costs. • In the context of TOU rates, CPUC staff assumed a blend of flat and equal percent of marginal cost (EPMC)[39] allocation to shape the non-marginal costs in proportion to the marginal costs. Modeling results suggest that a 50-50 blend of Flat and EPMC allocations works well when rates are uncapped. Transmission rates and NBCs are necessarily excluded from the EPMC shaping as described above.	50% Flat; 50% by EPMC for PG&E; 60/40 for SCE 85/15 for SDG&E (*)[40] (*)Proportional to the Sum of MEC, MGCC, & MDCC

Source: CPUC staff.

37 Marginal distribution capacity costs comprise only a portion of the distribution component of residential rates. The remainder of the distribution rate consists of marginal customer access costs and non-marginal distribution costs, which are included in the "Other Costs" component described below.

38 Unlike MECs and MGCC, there are no standard methods for allocating MDCC to TOU periods. However, all three IOUs have modeled such allocations for some ratesetting applications.

39 CPUC staff applied an EPMC methodology, which has a long history at the CPUC, dating to the earliest CPUC usage of marginal costs in rate-setting. In the Rate Reform Order Instituting Rulemaking, the following definition of EPMC was incorporated into an ALJ ruling: "Equal Percent Marginal Cost (EPMC): EPMC is a marginal cost-based revenue allocation method whereby all classes and rate schedules receive revenue requirement allocations that are the same percentage above or below their marginal cost revenues. Utilities often apply the EPMC to rate cases when requesting the Commission to approve allocation of authorized revenue according to marginal cost revenue."(March 19, 2013 ALJ Ruling, Attachment C, R.12-06-013)

40 CPUC staff believes these "Other" costs have no inherent variation with time or with customer demands for energy or capacity. Nevertheless, CPUC staff finds that there may be sound reasons to time-differentiate these non-marginal costs in proportion to the time differentiation of the marginal costs, based both on economic theory and on CPUC-precedent.

Table C-2: Detailed Rate Model Assumptions for Conceptual TOU Scenarios 5 & 6

	PG&E	SCE	SDG&E	Units
Base Year 2015 Fixed Charge (Non-CARE) [41]	$10	$10	$10	Per Month
CPI Escalator	2.1%	2.1%	2.1%	
Volumetric CARE Discount	32.5%	32.5%	32.5%	
Fixed Charge CARE Discount	50%	50%	50%	
Average Non-CARE Rate (2015)[42]	20.345	19.7	25.4	Cents/kWh
Marginal Distribution Rate Component (MDCC) (2015)	3.479	5.06	6.7	Cents/kWh
Transmission Rate (2015)	1.973	1.182	2.544	Cents/kWh
Other NBCs Rate Component (2015)	1.75	2.247	1.424	Cents/kWh
Marginal Generation Capacity Cost (2015)	$120.40	$120.40	$120.40	$/kW-year
Rate Component Escalation Rate	1.19%	1.38%	1.22%	
Number of Residential Households (Base Year)	4,648,200	4,426,273	1,345,240	
Care Percentage (Households)	26.8%	29.4%	22%	
Household Growth Rate	0.92%	0.89%	0.82%	
CARE Percentage (Sales)	28%	29.4%	22%	

Source: CPUC staff.

Other model inputs: In addition, the rate model required 8,760 hourly values for the following inputs:

- Hourly residential sales for 202143
- Hourly marginal energy prices44

41 At the time these study assumptions were made, the IOUs' fixed charge proposals in R.12-06-012 were pending a CPUC decision. The IOUs proposed to implement a $10 per month charge, the maximum allowed under AB 327. D.15-07-001 rejected these proposals and implemented a minimum bill instead. While not intended as an endorsement of the IOUs' fixed charge proposals, joint agency staff assumed a $10 fixed charge ($11.33 in 2021 adjusted for inflation) for **all** scenarios, as this was the most conservative view of potential load impacts of TOU (given that fixed charges may discourage conservation).

42 Components shown in bold were obtained from data requests to the utilities or utility tariff sheets.

43 Christensen Associates developed a standard set of reference loads for each utility, based on 2012 load profiles and updated forecasts of rooftop solar penetration.

44 Provided by Dr. Shucheng Liu of California ISO from the 2024 hourly energy market clean price (MCP) by zone-2014 LTPP Trajectory scenario, which assumes a 33 percent Renewables Portfolio Standard. According to Dr. Liu, here are some hours the MCP reaches $2,000/MWh. That is a sign that there is insufficient capacity to meet the sum of load and reserves. There are also some hours the MCP equals -$300 per megawatt hour when there is over-generation. No adjustment to this data was made by CPUC staff.