Estimating Default Dynamic Pricing Price Responsiveness for Medium C&I Customers

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ABSTRACT

From 2008 to 2010, the three investor-owned California utilities defaulted roughly 15,000 large and medium commercial and industrial (C&I) customers with approximately 4,400 MW of peak load onto default critical peak pricing (CPP). The customers ranged in size and included a wide range of industries, climate regions and tariffs. Over 2,800 of the accounts defaulted onto default CPP had average consumption per hour of 100 kWh or less. These customers are the focus of this paper.

The 2010 California experience provides the largest body of evidence to date regarding non-residential customer choices and price response on default dynamic pricing as well as the only source of data for medium customer price responsiveness under default dynamic pricing. In addition, 2010 was the first year when load response to critical peak pricing events could be observed after bill protection expired. It was also the first year for which persistence of CPP impacts could be estimated. The medium customer price response is extremely useful for guiding future policy decisions and for jurisdictions considering default dynamic pricing for commercial and industrial customers.

The paper details how medium customer price responsiveness with default dynamic pricing varied across key dimensions such as utility, industry, size, location and structural wins – that is, bill impacts under the revenue neutral dynamic pricing tariffs assuming no change in behavior. It also quantifies the effects of the removal of price protection on price response and the persistence of impacts across multiple years at SDG&E.

Introduction

By the summer of 2010, the three investor-owned California utilities – Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) – had defaulted approximately 15,000 commercial and industrial (C&l) accounts onto default critical peak pricing (CPP). Of the customers defaulted onto CPP, roughly 7,100 remained on the CPP tariff by the end of the summer. Combined, they accounted for approximately 2,200 MW of system coincident peak load. Over 2,800 of the accounts defaulted onto CPP had average consumption per hour of 100 kWh or less. Most of the prior studies on default non-residential dynamic pricing have been focused on large customers served under tariffs with peak prices that do not include the capital cost of peaking generation (capacity). The 2,800 customers with average consumption per hour of 100 kWh or less provide evidence of the response to default dynamic pricing among medium customers and are the focus of this paper.[1]

In the next three years, approximately 1,200,000 medium and small non-residential accounts are scheduled to default onto CPP across California. Combined, they account for roughly 8,500 MW during peaking conditions. The estimated 200,000 customers in California with annual non-coincident maximum demand between 20 and 200 kW are responsible for approximately 6,000 MW of these 8,500 MW. Because

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[1] The definition of medium customers varies across utilities throughout the U.S. and can range from customers with annual maximum demand of as little as 10 kW to customers with annual maximum demand of 500 kW.

the 2010 implementation of default CPP included a variety of customers by size, industry and climate, the results provide a wealth of information about how different types of medium customers respond to default dynamic pricing.

This paper is organized as follows: The next section provides a brief summary of CPP tariffs and the default process; this is followed by a comparison of customer characteristics; the third section describes the methodology used to estimate the percent load reductions. The following section presents the percent load reductions by utility, industry, size and location. The fifth section highlights other important findings from the study such as response by structural winners, persistence of impacts and the effects of bill protection. The final section summarizes the primary conclusions from the analysis.

Overview of CPP Tariffs and the Default Process

In 2009, the CPUC produced guidelines for dynamic pricing rate design. However, there are many differences in the details of the tariffs and the implementation processes across PG&E, SCE and SDG&E. Per CPUC guidelines, each utility implemented a CPP rate with an underlying TOU component as the default rate. With CPP rates, customers are exposed to higher prices during a specified window on critical peak event days. In exchange, customers are provided rate reductions during non-event days, including reduced demand charges. The event-day peak prices ranged from $1.20 to $1.33, varying by utility and service voltage level. The critical peak prices reflect both energy costs and the cost of building additional peaking power plants to meet high demand levels. By limiting energy usage during PDP event days, participants can reduce both their personal electricity bill and help limit the need to build additional peaking power plants. The rate reductions to offset CPP event day peak prices were mainly implemented in the form of reduced on-peak demand charges and ranged from approximately $5.67 to $12.50 per kW. All customers defaulted onto the tariff could opt-out to their prior Time of Use (TOU) tariff.

The actual TOU prices, CPP event prices, CPP credits and options associated with CPP, as well as many other relevant details, vary by utility. Table 1 summarizes the default CPP characteristics at each utility, as well as rate features such as rate periods, seasonal timing and other program characteristics. Almost all customers who were defaulted onto CPP transitioned from pre-existing TOU rates that already provided customers with strong incentives to shift or reduce electricity usage during peak periods. As a result, the price response under default CPP is likely smaller than if customers were to transition directly from flat rates to CPP. TOU prices vary by time-of-day but are otherwise constant throughout the summer. At all three utilities not only did energy prices vary by time of day, but demand charges were also higher during peak hours, producing even stronger incentives for customers to reduce electricity usage during peak hours or shift it to off-peak hours.

If just energy prices are considered, SCE's peak and off-peak prices are roughly 15¢ and 7¢, for a 2.1 peak to off-peak ratio. However, when demand charges are factored in, the peak to off-peak ratio is much greater. For example, one of SCE's TOU rates has an on-peak demand charge of $15.00 per kW that applies between 12 PM and 6 PM on summer weekdays. Roughly 128 hours per month are at risk for this on-peak demand charge. If the revenue from this summer on-peak demand charges ($/max kW) was converted to energy charges ($/kWh), assuming a load factor of 0.70, the on-peak energy price would increase by roughly 17¢. For SCE, factoring in this demand charge produces a peak to off-peak ratio of 3.7 (34.3¢/9.3¢). The TOU summer on-peak energy charges and demand charges give customers a significant incentive to reduce peak electricity use or shift it to off-peak hours absent implementation of default CPP.

Table 1. CPP Characteristics across California Utilities

CPP Characteristics	Utility		
	PG&E	SDG&E	SCE
Date of First CPP Default	May-10	May-08	Oct-09
Demand Criterion for CPP Default	>200 kW	>20 kW	>200 kW
Number of Months Demand Must Exceed Threshold	3 out of 12	12 out of 12	NA
Opt-Out Period	Rolling	Once Annually	Rolling
Event Period Hours	2 pm-6 pm	11 am-6 pm	2 pm-6 pm
Capacity Reservation Default	50%[1]	50%[1]	NA
First Year Bill stabilization	Yes	Yes	Yes
Event Season	Year-round	Year-round	Summer M-F
Number of Events	9 (Min) -15 (Max)	Maximum 18	9 (Min) -15 (Max)
Summer TOU Peak Hours	12 pm-6 pm, M-F	11 am-6 pm, M-F	12 pm-6 pm, M-F
Winter TOU Part-Peak Hours	NA	5pm-8pm, M-F	NA
Summer Season Definition	May-Oct	May-Sep	Jun-Sep
Winter Season Definition	Nov-Apr	Oct-Apr	Oct-May
TOU peak to off-peak price ratio [2]	2.9 to 3.2	2.6 to 2.8	3.6 to 4.8
CPP day peak prices (¢/kWh)	90¢ to 120¢	97¢ to 104¢	133¢ to 136¢
Demand charge credits ($/kW)	Peak: $5.67 to $6.31 Part-peak: $1.19 to $1.38	Peak: $5.81 Part-peak: $0.00	Peak: $11.6 to $12.5 Part-peak: $0.00
Energy charge credit (¢/kWh)	Peak: 0.4¢ Part-peak: 0.1¢	All hours: 0.6¢	0.0¢

[1] A Capacity reservation default level of 50% refers to 50% of the customer's max demand averaged over the prior year's summer months.

[2] The peak to off-peak ratio is a measure of the strength of the incentive to shift load from peak to off-peak hours. The calculation includes both differences in energy prices ($/kWh) and period-specific demand charges. On-peak and non-coincident demand charges were converted into an energy price based on the hours affected and a load factor of 0.7.

At all three utilities, the TOU peak period rate reductions designed to offset to CPP prices were substantial. The effect of these TOU rate reductions was not transparent because the rate reductions took the form of reduced consumption charges, reduced demand charges or both:

- For SDG&E CPP participants, the on-peak rate reduction is equivalent to 6.2¢ and 0.6¢ for all other hours. This amounts to a 24% decrease in on-peak prices and a 5% to 6% reduction in prices for all other hours.
- Participation in SCE's CPP rate lowers the on-peak demand charges by $11.6 to $12.5 per kW. This is equivalent to a 30% to 35% decrease in on-peak prices.
- PG&E's default CPP rate lowers both on-peak and part-peak summer demand charges and also provides a credit for energy charges during these rate blocks. The net effect is a reduction of 21% to 23% for on-peak periods and a 8% to 9% reduction in part-peak period prices.

Comparison of Customer Characteristics

PG&E has defaulted over 5,000 accounts onto CPP. By September 2010, slightly more than 1,800 accounts remained on the default tariff. SCE has defaulted over 8,000 accounts onto CPP. By the end of the 2010 summer, roughly 4,100 accounts remained. Since 2008, SDG&E has defaulted approximately 2,400 accounts and has retained over 1,350 accounts. At all three utilities, both large and medium customers were defaulted.

In practice, the definition of medium and large customers varies across utilities throughout the U.S. and ranges from customers with annual maximum demand of 10 kW to customers with annual maximum demand of 500 kW. Across all three utilities, 2,800 participants used 100 kWh or less on average. However, schools, which make up 700 of these 2,800 customers, are not included in the analysis. Average impacts for schools could not be accurately quantified without a proper control group due to the diversity in seasonal schedules between individual schools. Leaving out schools reduced the estimating sample of medium customers to roughly 2,100 accounts. Broken down across the three utilities, there were 412 accounts from PG&E, 1,259 accounts from SDG&E and 456 accounts from SDG&E that were suitable for the medium customer analysis. The remainder of this section breaks down the characteristics of these customers by utility, location, size and industry.

Table 2 shows the number of medium customers in each geographic area by utility. The table also shows the number of customers in four different bins of usage within each region. The 412 customers in PG&E's territory were located in areas with high heat intensity, such as Fresno, and in more temperate regions like the Bay Area. SCE and SDG&E serve more compact areas. Of all three utilities, a larger share of the SDG&E customers on default CPP had annual average hourly consumption below 50 kWh per hour.

Table 2. Enrollment during the Average 2010 CPP Event by Utility and Geographic Area

Utility	Location	Annual Average Hourly Consumption				
		25 kWh/hr or less	25-50 kWh/hr	50-75 kWh/hr	75-100 kWh/hr	TOTAL
PG&E	Greater Bay Area	1	28	40	94	163
	Central Valley	64	11	14	23	112
	Other	25	18	43	51	137
	TOTAL	**90**	**57**	**97**	**168**	**412**
SCE	LA Basin	79	180	334	453	1,046
	Outside LA Basin (Desert)	6	18	17	31	72
	Other (Ventura/ Big Creek)	8	27	47	59	141
	TOTAL	**93**	**225**	**398**	**543**	**1,259**
SDG&E	San Diego	114	109	103	130	456
	TOTAL	**114**	**109**	**103**	**130**	**456**

Table 3 shows the industry mix among the relevant CPP customers for the average event day by utility; it also shows the range of customer hourly electricity demand during CPP event conditions. 50% of customers had demand levels between the 25th and 75th percentiles during critical system conditions. SCE had far more accounts that met the criteria for this study than PG&E or SDG&E, but the SCE customers were generally larger. The first three industry groups – Mining & Construction, Manufacturing and Wholesale & Transport – are industrial operations. The remaining four business groups are commercial. Roughly half of the relevant PG&E accounts on default CPP are commercial. For SCE about 45% of accounts are commercial and approximately 55% of SDG&E accounts are commercial. Understanding industry mix in the medium CPP population at each of the California utilities is important because it can explain systemic differences in medium CPP customer impacts by utility. At each utility, the majority of participants are either in the Manufacturing sector or Offices & Hotels sector.

Table 3. CPP Industry Mix Across California Utilities and Peak Loads for Customers with Annual Average Hourly Consumption Below 100 kWh/hr

Industry	PG&E			SCE			SDG&E		
	Accts	Peak Load (kW) Percentile		Accts	Peak Load (kW) Percentile		Accts	Peak Load (kW) Percentile	
		25th	75th		25th	75th		25th	75th
Mining & Construction	23	18.2	115.1	48	13.6	107.2	3	39.0	155.4
Manufacturing	113	53.5	130.2	430	60.4	139.1	66	42.8	132.7
Wholesale & Transport	69	17.7	125.1	206	44.6	140.8	136	15.7	86.9
Retail Stores	20	17.9	189.7	91	91.4	167.6	20	27.8	147.3
Offices & Hotels	125	3.5	178.7	311	103.7	172.8	133	37.8	152.8
Institutional/Government	47	3.5	157.4	138	63.9	150.6	96	20.1	125.2
Other or Unknown	15	0.2	80.4	35	18.3	133.0	2	81.7	170.0
ALL CUSTOMERS	**412**	**25.1**	**154.8**	**1259**	**62.5**	**153.8**	**456**	**25.8**	**122.5**

Methodology

Based on the program dispatch pattern, CPP naturally produces an alternating or repeated treatment design. The primary intervention – event days with higher critical peak prices – is introduced on some days and not on others, making it possible to observe behavior with and without events under similar conditions. A repeated treatment design enables us to assess whether the dependent variable – hourly electricity usage – rises or falls with the presence or absence of the main treatment, a critical peak pricing event. The entire event day is evaluated to estimate both load reductions during event hours and load shifting to non-event hours. The natural variation in CPP allows us to estimate the impact of event days relative to non-event days.

We relied on individual customer regressions as our primary method for calculating ex post impacts. The ex post estimated models are based on hourly load data for each customer, including a year of pre-enrollment data. The use of pre-enrollment data helps ensure that factors correlated with CPP event days are not confounded with rate impacts. This is important because CPP event days tend to coincide with hot temperatures and response to CPP prices can be confounded with weather when pre-enrollment data is not employed. The dependent variable is the average hourly demand (kW) in each time period for each participant. In total, 2 years or 17,520 observations were used for almost every participant. The model is intentionally flexible in order to capture usage patterns at the individual customer level. The variables included in the regression and corresponding definitions are detailed in Table 4. Mathematically, the regression model can be expressed as:

$$kW_t = A + \sum_{i=1}^{24} B_i \times Hour_i \times Year2010 + \sum_{i=1}^{24}\sum_{j=1}^{5} C_{ij} \times Hour_i \times DayType_j$$
$$+ \sum_{i=1}^{24}\sum_{j=1}^{12} D_{ij} \times Hour_i \times Month_j + \sum_{i=1}^{24} E_i \times Hour_i \times TotalCDH_t$$
$$+ \sum_{i=1}^{24} F_i \times Hour_i \times TotalCDHsqr_t + \sum_{i=1}^{24} G_i \times Hour_i \times TotalHDH_t$$
$$+ \sum_{i=1}^{24} H_i \times Hour_i \times TotalHDHsqr_t + \sum_{i=1}^{24} I_i \times Hour_i \times SummerCPP_t$$
$$+ \sum_{i=1}^{24} J_i \times Hour_i \times WinterCPP_t + \sum_{i=1}^{24} K_i \times Hour_i \times OtherDR_t$$
$$+ \sum_{i=1}^{24} L_i \times Hour_i \times Eventday_t + \sum_{i=1}^{24} M_i \times Hour_i \times Eventday_t \times TotalCDH_t + \varepsilon_t$$

Table 4. Variable definitions and Logic for Inclusion in Evaluation Model

Variable	Definitions and Logic for Inclusion
kW_t	Represents the average hourly demand (kW) for each time period;
A	Is the estimated constant term;
B through M	Represent the regression model parameters;
$Hour_i$	Is a series of binary variables for each hour. They account for the basic hourly load shape of the customer after other factors such as weather and prices are accounted for;
$Year_j$	Is a binary variable with a value equal to 1 for 2010. It was included to reflect changes in overall load patterns and economic conditions between the pre- and post-enrollment periods;
$DayType_j$	Is a series of binary variables representing five different day types (Mon, Tues-Thurs, Fri, Sat, Sunday/Holiday);
$Month_j$	Is a series of binary variables for each month designed to reflect seasonality in loads;
$TotalCDH_t$	Is a measure of heat intensity for the day. It is the sum of cooling degree hours (base 65) for the day;
$TotalCDHsqr_t$	Is the square of the above variable;
$TotalHDH_t$	Is the sum of heating degree hours (base 65) for the day;
$TotalHDHsqr_t$	Is the above variable squared;
$SummerCPP_t$	Is a binary variable representing a customer's CPP status (enrolled or not enrolled) on summer weekdays in interval t. Interacting it with the hourly binary variables quantifies the incremental effects of the summer weekday CPP rate discounts on the pre-default TOU rate;
$WinterCPP_t$	Is a binary variable representing a customer's CPP status (enrolled or not enrolled) on winter weekdays in interval. By interacting it with the hourly binary variables, the effects of the

Variable	Definitions and Logic for Inclusion
	differences between the pre-default TOU rate and the CPP rate in the winter period are captured;
$OtherDR_t$	Is a binary variable representing a customer's participation in another DR event in interval t;
$Eventday_t$	Is a binary variable representing a CPP event day in interval t,[2] and;
e_t	Is the error term.

A number of these variables explain variation in customer loads patterns by time-of-day, day-of-week, month, year, temperature and participation in other DR programs. These variables were each interacted with each hour of the day to reflect differences in behavior across hours and months due to operation schedules. However, the primary goal of the regressions was to accurately estimate the impact of the change in prices associated with the shift to default CPP. Clearly, this meant estimating the impact of CPP prices on event days. However, the decreases in summer weekday peak demand and consumption charges were too substantial to ignore. In other words, there were two interventions with default CPP: an increase in CPP prices and rate discounts on regular summer weekdays. It has been argued that unless the rate discounts are explicitly into account, the impact of CPP rates may be overstated.

To estimate the impact of CPP prices, event days were interacted with prices and weather. This captured both load reductions during high-priced CPP periods, shifting to periods before and after the CPP prices and differences in response associated with weather conditions. To estimate the effect of the rate discount, whether or not the customer was enrolled on CPP during the summer was interacted with hour. This estimated the incremental changes in electricity use patterns between the pre-default and CPP period after controlling for other factors. In other words, it estimated the change in electricity use associated with the rate reductions, which were in effect each day. This approach estimated impacts through treatment variables and avoided imposing theoretical pre-conceptions about how customers respond to dynamic pricing and about functional form (i.e., assumption such as constant price elasticities or a log-log functional form).

Validation Methods

The validation of the regression models focused on lack of bias and precision. An unbiased model produces accurate impact estimates. A model with high precision produces estimates with smaller standard errors and tighter confidence bands. The precision of the estimates is particularly important when percent load reductions are relatively small. Lack of bias and precision are closely related but are not the same. We are interested foremost in accuracy or lack of bias in the impact estimates.

Estimating the bias of a regression model requires knowledge of the actual electricity use patterns in the absence of DR and event impacts. During event days, the load without the critical peak price in effect cannot be directly observed, it must be estimated. However, actual load patterns without DR can be observed for event-like days during both pre-enrollment and post-enrollment periods.

For each utility we performed out-of-sample tests by defining groups of days similar to event days, withholding those days from the regression database, predicting out-of-sample for those days and then comparing the predicted load on those days to the actual load. This produces a measure of percent bias for individual customers, which we can use to assess if biases are systematic across observable customer characteristics such as location, business type and weather sensitivity. The out-of-sample tests were conducted on a sample of all customers used in the evaluation and included large customers. However, for

[2] SCE had 12 events during the time period included in the estimation, whereas PG&E had 9 events and SDG&E had 4 events.

each medium participant, we calculated a similar in-sample measure of bias by comparing predicted versus actual electricity usage patterns during event-like hours.

The event-like days were sampled from the hottest days in the pre-CPP and non-event day history of each customer. For all three utilities, the regression models produce highly accurate estimates of the actual load. For PG&E, SCE and SDG&E the difference between predicted and actual values across the event window was less than 0.2%, 0.9% and 1.1%, respectively.[3] After removing the 1% of customers with high bias, the difference between predicted and actual values for event-like hours was -2.1%, 0.1%, 0.9% for PG&E, SCE and SDG&E medium customers, respectively. The high degree of accuracy of these out-of-sample event-like tests adds confidence that the regressions produce accurate counterfactuals and impact estimates.

In addition to testing out-of-sample predictive accuracy, false event-day variables were included during event-like days to determine if error was being confounded with critical peak pricing conditions. This was done as part of the overall program evaluation and the sample pulled for this test included large customers. The coefficients on the false event-day variables should be insignificant and centered around zero because there are no DR events on false event days. If the coefficients on these false event-day variables impact actual electricity usage by close to 0%, it is reasonable to conclude that error is not being confounded with the treatment effects and that the model is specified correctly. If the difference is substantial, the model is incorrectly specified and needs to be improved. In practice, coefficients are sometimes significant due to the large number of observations analyzed,[4] so we looked at the percent by which the false event-day coefficients impact actual electricity usage.

Table 5 shows the degree of bias in the false event-day coefficients during event hours. The default assumption is that the false event day and hour interactions should have close to 0% impact on the dependent variable, otherwise there is evidence that event hours are correlated with the error term. Except for PG&E, all of the coefficients on the false event day and hour interactions are insignificant. For SCE, the coefficients on the estimated false event day and hour interactions bias actual kWh by 0.04%. For SDG&E, the bias is 0.26%. PG&E shows a small degree of bias, 2.32%.

Table 5. False Event Coefficient Tests

Event hour	SCE		PG&E		SDG&E	
	T-Value	% Bias	T-Value	% Bias	T-Value	% Bias
11 AM to 12 PM	-	-	-	-	0.52	0.06%
12 PM to 1 PM	-	-	-	-	-0.35	-0.04%
1 PM to 2 PM	-	-	-	-	1.83	0.27%
2 PM to 3 PM	0.56	0.18%	13.02	2.43%	0.9	0.14%
3 PM to 4 PM	0.27	0.08%	13.36	2.52%	1.97	0.32%
4PM to 5 PM	-0.47	-0.15%	12.58	2.42%	2.45	0.38%
5 PM to 6 PM	-0.90	-0.30%	9.07	1.86%	5.75	0.73%
TOTAL	-0.27	-0.04%	24.01	2.32%	4.88	0.26%

Table 6 summarizes the amount of variation explained by the regressions for each industry and for the average customer. Across all three utilities, the regressions explain over 97% of the variation around the

[3] These numbers were pulled from the main evaluation, which includes large customers.

[4] Statistical power is a function of the amount of data. With a large volume of data, even small differences are significant. For each customer, almost two years of interval data was used – roughly 16,000 observations. For each utility, tens of millions of observations were used in estimating aggregate impacts.

mean. In other words, factors not included in the regression account for less than 3% of the variation in average customer behavior and electricity usage patterns. The likelihood that CPP effects are confounded with unaccounted factors is minimal. For almost all industries in each utility, well over 90% of the variation in electricity usage is explained.

Table 6. R-squared values by Industry for Each Utility

Industry	R-squared		
	PG&E	**SDG&E**	**SCE**
Mining & Construction	0.82	0.86	0.92
Manufacturing	0.94	0.94	0.95
Wholesale & Transport	0.87	0.88	0.93
Retail Stores	0.99	0.98	0.99
Offices & Hotels	0.98	0.97	0.98
Institutional/Government	0.94	0.97	0.90
All Customers	0.98	0.97	0.97

Default CPP Load Impacts

Table 7 provides the estimated average reduction in electricity demand by industry and utility for medium customers for 2010 CPP event hours. The percent impacts vary substantially across utilities and industries. PG&E had the largest load reductions. On average, their medium-sized participants, excluding schools, reduced electricity usage by 10.0% during CPP event hours. In contrast, medium customers at SCE and SDG&E averaged percent reductions of 1.2% and 3.3% across all events, respectively. There are several potential explanations for the higher percent impacts from PG&E's medium CPP customers. First, the retention rate for default CPP was lower for PG&E than for SCE and SDG&E at 40%. In other words, Second, the PG&E rates had a relatively high CPP charge of $1.20 per kWh. And, the pre-existing TOU tariffs at PG&E did not provide as strong an incentive to shift or reduce electricity usage during peak periods as the pre-existing TOU tariffs at SCE and SDG&E. Put differently, the relative increase in peak period prices under default CPP was higher for PG&E customers.

An each utility, customers in industrial businesses produced larger percent load reductions than those in commercial enterprises. The percent reductions in electricity demand for industrial customers ranged from 17.2% at PG&E, to 4.6% at SCE and 7.2% at SDG&E. These impacts differ markedly from those provided by commercial customers. Except for those at PG&E, commercial customers did not reduce electricity usage during event day peak hours. Across all utilities, the Offices industry group did not provide load response. This may be due to several factors. First, the opportunity cost of shifting or reducing load may be higher than the losses incurred under event day prices for these customers. Second, many offices are in multi-tenant facilities with centrally controlled energy systems. Building owners are unlikely to adjust thermostat settings or lighting for their tenants without advance permission. Third, event day impacts are more difficult to disentangle for weather sensitive commercial customers. Operating schedules, hot weather, TOU prices and CPP prices are closely related and can be confounded. While the validation analysis did not indicate a bias in the results for offices, there may very well be subtle, but substantive, differences between the event-like days used for validation and the actual event days. This appears to be the case for SCE, since the load impacts run counter to what is expected under higher event day prices.

On average, the impact of the price reduction on the TOU components of the rate was not statistically significant. The reductions in prices were substantial in percentage terms, bud did not lead to large enough changes in electricity consumption for them to be statistically significant.[5] This doesn't mean that customers did not increase weekday on-peak electricity use due to the rate discounts. It simply means that the changes were too small to rule out random variation as an explanation.

Table 7. Estimated Ex Post Percent Load Impacts by Industry, Average 2010 CPP Event

Industry	PG&E			SCE			SDG&E		
	Reference Load	Average Event Impact per Customer	Percent Reduction	Reference Load	Average Event Impact per Customer	Percent Reduction	Reference Load	Average Event Impact per Customer	Percent Reduction
	kW	kW	%	kW	kW	%	kW	kW	%
Mining & Construction	70.7	21.4	30.3%	64.5	3.4	5.0%	94.1	22.6	24.0%
Manufacturing	96.9	13.4	13.9%	95.7	5.4	5.3%	88.1	6.1	7.0%
Wholesale & Transport	81.1	16.0	19.8%	90.8	2.7	2.9%	55.6	3.7	6.7%
Retail Stores	105.0	11.0	10.4%	129.9	-0.2	-0.1%	91.8	2.9	3.2%
Offices & Hotels	104.9	-1.0	-1.0%	136.0	-3.2	-2.4%	98.4	-0.5	-0.5%
Institutional/Government	89.7	9.2	10.3%	112.7	-1.3	-1.2%	74.6	2.3	3.1%
All Customers	**92.8**	**9.3**	**10.0%**	**109.1**	**1.3**	**1.2%**	**78.9**	**2.6**	**3.3%**
Commercial	**96.9**	**3.4**	**3.5%**	**124.1**	**-2.5**	**-2.0%**	**89.0**	**0.8**	**0.9%**
Industrial	**88.6**	**15.2**	**17.2%**	**96.5**	**4.4**	**4.6%**	**66.6**	**4.8**	**7.2%**

Even within the subset of customers used for this analysis, there is substantial variation in customer size. Table 8 shows the percent load reductions for customers of different sizes in the commercial and industrial sectors. At each utility, industrial customers across the range of the medium population reduced load during default CPP events. In other words, the reductions were not restricted to the largest customers. For commercial customers at SDG&E and PG&E, customers on the smaller side of the size spectrum produced the largest percent load reductions. While this is an important finding, at this stage it is not prudent to conclude that the pattern will hold for commercial customers within or outside of California as more customers are defaulted onto dynamic pricing.

Table 9 shows load impacts by geographic area. The climate in California is diverse and includes areas with high heat intensity, such as the Central Valley, as well as more temperate regions like the Bay Area and San Diego. Industrial customers in each geographic area reduced electricity usage during CPP event hours. Based on the table, the reductions are larger in hotter areas such as the Central Valley, Outside the Los Angeles Basin and in PG&E's Other category. However, there are differences in both the customer mix and underlying rates between geographic areas. What is clear is that price response is not restricted to specific geographic areas. For commercial customers, the results vary substantially. SCE and SDG&E, commercial customers did not provide meaningful reductions. At PG&E, the results for commercial

[5] This is best understood through an example. For PG&E, the net effect of the default CPP rate discounts is a reduction of 21% to 23% for on-peak periods on regular weekdays. This translates into a peak to off-peak price ratio is 2.26 rather than 2.94. In comparison, during CPP event days, the peak-to-off peak price ratio is 11.2. Given customer price elasticities, the percent change in on-peak electricity change associated with the rate discount is trivial and difficult to detect.

customers vary quite widely with customers in the Central Valley, who are also generally smaller, producing the largest percent reductions.

Table 8. Estimated Ex Post Percent Load Impacts by Size Category, Average 2010 CPP Event

Utility	Consumption Category	Commercial			Industrial		
		Accts	Reference Load	Reduction	Accts	Reference Load	Reduction
	Annual Avg. kWh/hr		kW	%		kW	%
PG&E	25 kW or less	68	3.5	27.8%	22	8.8	26.8%
	25 to 50	17	70.4	5.3%	40	47.3	18.6%
	50 to 75	31	120.0	4.0%	66	90.9	16.5%
	75 to 100	91	163.7	2.9%	77	131.0	17.1%
	Total	**207**	**96.9**	**3.5%**	**205**	**88.6**	**17.2%**
SCE	10 to 25	41	18.0	-	52	15.7	8.5%
	25 to 50	78	58.9	-	147	54.0	3.6%
	50 to 75	164	124.5	-	234	96.8	4.5%
	75 to 100	292	156.2	-	251	137.8	4.8%
	Total	**575**	**124.1**	**-2.0%**	**684**	**96.5**	**4.6%**
SDG&E	10 to 25	65	20.0	5.7%	49	19.1	8.8%
	25 to 50	52	57.6	0.8%	57	45.4	0.5%
	50 to 75	55	114.1	-0.3%	48	86.6	4.7%
	75 to 100	79	149.0	1.1%	51	117.3	11.5%
	Total	**251**	**89.0**	**0.9%**	**205**	**66.6**	**7.2%**

Table 9: Estimated Ex Post Load Impacts by Local Capacity Area, Average 2010 CPP Event

Utility	Consumption Category	Commercial			Industrial			Max Temp	Min Temp
		Accts	Reference Load	Reduction	Accts	Reference Load	Reduction		
	Annual Avg. kWh/hr		kW	%		kW	%	°F	°F
PG&E	Greater Bay Area	82	150.6	2.4%	81	95.8	9.4%	61.7	88.6
	Central Valley	71	40.1	9.6%	41	69.4	16.2%	70.4	99.9
	Other	54	89.9	2.9%	83	91.1	25.5%	62.3	95.4
	TOTAL	**207**	**96.9**	**3.5%**	**205**	**88.6**	**17.2%**	**64.2**	**93.9**
SCE	LA Basin	468	123.4	-	578	98.4	4.1%	65.1	89.4
	Outside LA Basin (Desert)	38	123.5	-	34	80.5	19.4%	64.7	95.4
	Other (Ventura/ Big Creek)	69	129.0	-	72	88.6	2.5%	60.2	84.8
	TOTAL	**575**	**124.1**	**-2.0%**	**684**	**96.5**	**4.6%**	**64.5**	**89.2**
SDG&E	San Diego	251	89.0	0.9%	205	66.6	7.2%	68.7	87.1
	TOTAL	**251**	**89.0**	**0.9%**	**205**	**66.6**	**7.2%**	**68.7**	**87.1**

Structural Wins, Bill Protection and Persistence of Impacts at SDG&E

For SDG&E, it was possible to analyze persistence of impacts across multiple years and the effect of bill protection due to a unique combination of program roll-out and regulatory decisions. In addition, we also analyzed the relationship between structural wins and losses and percent load reductions.

At SDG&E, bill protection expired for most CPP participants in May 2009, as initially scheduled. However, halfway through the 2009 summer, the CPUC extended bill protection for customers that defaulted in 2008 for an additional year. For the first half of 2009, these customers would have provided price response as if bill protection had expired since the extension of bill protection was not known at the time. For the latter half of the 2009 summer, they provided price response knowing bill protection was in place. The regulatory change provided a unique opportunity to disentangle the effects of multi-year participation from bill protection.

The primary intent of bill protection is to encourage risk-averse customers to try dynamic rates. With bill protection, consumers are guaranteed that they will not pay more under the CPP tariff than they would under the alternate opt-out TOU rate. At some point in time, typically at the end of a year or the end of a tariff season, a customer's bill is calculated based on the opt-out TOU rate and the CPP rate, and they are refunded the difference, if any, between the CPP rate and the opt-out TOU rate. Basic economic theory suggests that bill protection should eliminate customer response to CPP events that is based solely on financial motives. However, in practice, the potential for reimbursement at the end of the summer is often outweighed by the immediacy of paying higher summer monthly bills. The period under bill protection was also the only chance for customers to figure out how the CPP rate would impact them financially. It was in their interest to proceed with business as usual during the bill protection period as to accurately determine whether or not a CPP tariff was in their best interest.

The introduction of default CPP creates structural winners and losers and, as a result, can be controversial. While dynamic pricing rates have many benefits, altering hourly prices can change customer bills even if they do not change their behavior. Under flat pricing, customers who use more electricity during high-cost periods and drive the need for additional peaking generation are subsidized by those who do not. While a TOU price signal can address differences in electricity production costs, it does not reflect that the need for additional generation or transmission capacity is highly concentrated in relatively few hours. Put differently, capital investment in electricity use are driven by coincident peak demands and are often not closely related to electricity production costs reflected in wholesale market prices. Because of their load shapes, some customers benefit from the transition to default CPP and opt-out TOU absent any changes in their electricity consumption behavior, while other customers lose their cross-subsidies.

To estimate the effects of bill protection, persistence of impacts and structural wins, the percent impacts from each event day experienced by each customer were regressed as a function of multi-year participation, bill protection, CPP price insurance (capacity reservation levels), structural wins, 10 industry types, average temperature throughout each event and customer size groups. The regression analysis included all 2009 and 2010 event days experienced under default CPP. The analysis was possible because we had CPP impact estimates for each customer and event day. Mathematically, the regression model can be expressed as:

$$
\begin{aligned}
PercentImpact_{it} = {} & A + B_i \times PctWinsBins_i + C_i \times Industry_i + D_i \times SizeBins_i \\
& + E_{it} \times Temperature_{it} + F_{it} \times CRL_{it} + G_{it} \times Persistence_{it} \\
& + H_{it} \times BillProtection_{it} + v_{it}
\end{aligned}
$$

The regression on percent load impacts tells us how different characteristics and program features relate to percent load reductions. However, the results of this regression cannot be interpreted as causal since there are potential unobservable characteristics that may not be fully accounted for in the model. The individual customer percent impacts also contain measurement error, which can be problematic if it is systematic and correlated with the dependent variable. If uncorrelated with the dependent variable, measurement error simply produces wider, more conservative confidence bands. The individual customer estimates of bias were analyzed to determine if there were systematic differences due to industry, location and weather sensitivity. There were no substantive systematic biases.

The focus of research is often on statistically significant differences. In this instance, a finding of no difference has substantive policy implications. The dummy variable for persistence of impacts was insignificant, indicating that customers do not behave differently during their second or third year on the CPP program. The marginal effect of the dummy variable for bill protection was also not significant. In the case of structural wins, the variables were statistically significant. Customers that experienced structural wins provided larger percent load impacts than structural losers. While in the residential sector, customers with more peak usage due to AC use typically have more discretionary load: structural winners in the commercial and industrial sectors are usually customers with flatter load shapes.

Conclusions

The 2010 California experience provides the largest body of evidence to date regarding medium non-residential customer choices and price response on default dynamic pricing. Several conclusions can be drawn from the California experience:

- When defaulted onto dynamic rates, substantial shares of customers remain on the dynamic rate.
- Customers defaulted onto dynamic rates reduce consumption during peak event hours even without enabling technology.
- Industrial customers provide larger percent load reductions than commercial customers.
- Customers of various sizes and in different climate regions engage in price response.
- Bill protection does not have a statistically significant effect on price response.
- Price response persists into the 2nd and 3rd year of participation.

While customers reduced use in response to default dynamic pricing, the percent load reductions were not large. This is due, in part, to the fact that customers were transitioned from pre-existing TOU rates that already strongly encouraged them to reduce or shift peak electricity usage. Customers who transition from flat rates to similar CPP rates should provide larger percent reductions.

Several policy questions remain. To date, impacts for small C&I customers are based on opt-in pilots. Relatively little is known about their participation and pricing response in actual programs and even less is known about their response under default dynamic pricing. In addition, for both small and medium customers, relatively little is known about how offering enabling technology affects their acceptance of these rates. In practice, many customers are concerned about bill volatility both with and without dynamic pricing. Another key research question is how coupling dynamic pricing with balanced payment plans, which eliminate bill volatility, will affect acceptance of default dynamic rates as well as price response.