- Slight energy conservation effects resulted from residential consumption under TOU rates compared to residential consumption under the flat tariffs.
- Conservation effects were larger in winter than in summer for the residential customers.
- Business customer price elasticities are not statistically significant. Therefore, they should be interpreted with caution.

Energy Australia started the Strategic Pricing Study in 2005 which included 1,300 voluntary customers (50 percent business, 50 percent residential customers). The study tested seasonal, dynamic, and information only tariffs and involved the use of in-house displays and online access to data. Study participants received dynamic peak price signals through Short Message Service (SMS), telephone, email, or the display unit.

Preliminary results that are available from three dynamic peak pricing (DPP) events show that:

- Residential customers reduced their dynamic peak consumption by roughly 24 percent for DPP high rates (A$2+/kWh) and roughly 20 percent for DPP medium rates (A$1+/kWh).
- Response to the 2nd DPP event was greater than that to the 1st DPP event. This may be attributed to the day-ahead notification under the 2nd DPP event (versus day-of notification under the 1st DPP event) and/or temperature differences.
- Response to the 2nd event was also greater than to the 3rd DPP event. This may be explained by lower temperatures on the 3rd DPP event which may have led to less discretionary appliances to turn off.

ONTARIO/CANADA- ONTARIO ENERGY BOARD SMART PRICE PILOT[29]

The Ontario Energy Board operated the residential Ontario Smart Price Pilot (OSPP) between August 2006 and March 2007. The OSPP used a sample of Hydro Ottawa residential customers and tested the impacts from three different price structures:

- The existing Regulated Price Plan (RPP) TOU: The RPP TOU rates are shown in Table 26.
- RPP TOU rates with a CPP component (TOU CPP). The CPP was set at C$0.30 per kWh based on the average of the 93 highest hourly Ontario electricity prices in the previous

[29] Ontario Energy Board, "Ontario Energy Board Smart Price Pilot Final Report," 2007.

year. The RPP TOU off-peak price was decreased to C$0.031 (from C$0.035) per kWh to offset the increase in the critical peak price. The maximum number of critical day events was set at nine days, however only seven CPP days were called during the pilot.

- RPP TOU rates with a critical peak rebate (TOU CPR): The CPR provided participants with a C$0.30 per kWh rebate for each kWh of reduction from estimated baseline consumption. The CPR baseline consumption was defined as the average usage during the same hours over the participants' last five non-event weekdays, increased by 25 percent.

Table 26- Regulated Price Plan (RPP) TOU Rate Design

Season	Time	Charge	Applicable
Summer (Aug 1- Oct 31)	Off-peak	C$0.035/kWh	10 p.m.- 7 a.m. weekdays; all day on weekends and holidays
Summer (Aug 1- Oct 31)	Mid-peak	C$0.075/kWh	7 a.m.- 11 a.m. and 5 p.m.- 10 p.m. weekdays
Summer (Aug 1- Oct 31)	On-peak	C$0.105/kWh	11 a.m.- 5 p.m. weekdays

A total of 373 customers participated in the pilot: 124 in TOU-only, 124 in TOU-CPP, and 125 in TOU-CPR. The control group included 125 participants who had smart meters installed but continued to pay non-TOU rates.

The OSPP results show that:

- The load shift during the critical hours of the four summer CPP events ranged between 5.7 percent and 25.4 percent. [30]
- The load shift during the entire peak period of the four summer CPP events ranged between 2.4 percent and 11.9 percent.

Table 27 shows the shift in load during the summer CPP events as a percentage of the load in critical peak hours and of the entire peak period. It is important to note that the percentage reductions for the TOU-only customers are not significant at the 90 percent confidence level.

[30] Under the OSPP, 3 to 4 hours of the peak period were defined as critical on a CPP day.

Table 27- Percentage Shift in Load during the Four Summer CPP Events

Period	TOU- only	TOU- CPP	TOU- CPR
Shift as % of critical peak hours	5.7%	25.4%	17.5%
Shift as % of all peak hours	2.4%	11.9%	8.5%

This study also analyzed the total conservation impact during the full pilot period. The total reduction in electricity consumption due to program impacts is reported in Table 28. The average conservation impact across all customers was estimated to be six percent.

Table 28- Total Conservation Effect for the Full Pilot Duration

Program	% Reduction in Total Electricity Usage
TOU-only	6.0%
TOU- CPP	4.7% (ns)
TOU- CPR	7.4%
Average Impact	6.0%

SEATTLE SUBURBS- PUGET SOUND ENERGY (PSE)'S TOU PROGRAM[31]

PSE initiated a TOU program for its residential and small commercial customers in 2001. The rate design involved four price periods. Prices were most expensive during the morning and evening periods with mid-day and economy periods following these most expensive periods. Some 300,000 PSE customers were placed in the program and given the option to go back to the standard rates if they were not satisfied with the program. The peak price was roughly 15 percent higher than the average price that prevailed before the program and the off-peak price was 15 percent lower. In 2002, the second year of the program, customers were charged a monthly fee of $1 per month for meter-reading costs. The results of PSE's quarterly report revealed that the 94 percent of the customers paid an extra $0.80 (the total of $0.20 power savings and $1 meter reading costs) by participating in the pilot. This was in contrast with the first year results where customers were not charged meter reading costs and around 55 percent of them experienced bill savings. As a result of customer dissatisfaction and negative media coverage, PSE ceased its TOU program. Following are several lessons that were derived from this experience:

[31] Faruqui, A., S. S. George. 2003. "Demise of PSE's TOU Program Imparts Lessons." Electric Light & Power Vol. 81.01:14-15.

- Modest price differentials between peak and off-peak may induce customers to shift their load if they are accompanied with unusual circumstances such as the energy crisis of 2000-2001 in the West. An independent analysis of the program found that the customers lowered peak usage by five percent per month over a 15 month period, with reductions being slightly higher in the winter months and slightly lower in the summer months.
- It is important to provide the customers with accurate expectations about their bill savings.
- It is essential to offer a pilot program before implementing a full-scale program.

WASHINGTON- THE OLYMPIC PENINSULA PROJECT[32]

The Olympic Peninsula Project was a component of the Pacific Northwest GridWise Testbed Demonstration that took place in Washington and was led by the Pacific Northwest National Laboratory (PNNL). The Peninsula Project tested whether automated two-way communication systems between grid and passive resources (i.e., end use loads and idle distributed generation) and the use of price signals as instruments would be effective in reducing the stress on the system. Our review focuses on the residential response and does not cover the impacts associated with the distributed generation resources.

By the end of 2005, the project recruited participants with the assistance of the local utility companies. The project received a mailing list from the utilities of the potential participants who had high-speed internet, electric HVAC systems, electric water heater, and electric dryer. Letters were mailed to these customers to recruit potential participants. At the end of the recruiting process, 112 homes were installed with the two-way communication equipments that allowed utilities to send the market price signals to the consumers and allowed consumers to pre-program their demand response preferences. These residential participants were then evenly divided into three treatment groups and a control group. Equipment was also installed in the control group homes but they were given no additional information.

Each treatment group was assigned to one of the three electricity contracts:

- Fixed-prices: prices remained constant at all times.

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32 Pacific Northwest National Laboratory. "Pacific Northwest GridWise Testbed Demonstration Projects Part 1: Olympic Peninsula Project", 2007.

- Time-of-use/critical peak prices (TOU/CPP): prices differed between peak and off-peak time periods. Peak price were much higher during critical peak days.
- Real time prices: prices under this contract were unpredictable and varied every five minutes. Participants in this contract responded to real time prices by pre-setting their appliance controls for their preferences through the web but they still had the option to override their preferences at any time.

Table 29 shows the prices that prevailed under fixed price and TOU/CPP contracts.

Table 29- Experimental Rate Design

Contract	Season	Period	Charge	Applicable
Time-of-Use/ CPP	Spring (1 Apr-24 Jul) and Fall/Winter (1 Oct-31 Mar)	Off-peak	$0.04119/kWh	9 am-6pm and 9pm-6am
		On-peak	$0.1215/kWh	6am-9am and 6pm-9pm
		Critical	$0.35/kWh	Not called
	Summer (25 Jul- 30 Sep)	Off-peak	$0.05/kWh	9am-3pm
		On-peak	$0.135/kWh	3pm-9pm
		Critical	$0.35/kWh	When called
Fixed-Price	All seasons	All day	$0.081/kWh	All hours

Results from the pilot are as follows:

- The fixed-price group saved two percent on their average monthly bill compared to the control group; the time-of-use pricing group saved 30 percent and the real time pricing group saved 27 percent.
- Differences in average energy consumption between the contract groups were small but statistically significant. The time-of-use group consumed 21 percent less energy and achieved conservation benefits from time-of-use pricing. The real time group consumed as much as the control group. The fixed-price group used four percent more energy than the control group. The usage comparison across the contract groups is presented in Table 30.

Table 30- Average Daily Energy Consumption per Home (April 06- December 06)

Contract Type	Average Daily Energy Consumption (kWh)	Standard Deviation(kWh)	Percentage Difference (compared to the control)
Control	47	24	0%
Fixed	49	22	4%
Time-of-Use	39	29	-21%
Real-Time	47	26	0%

- Examination of the residential load shapes by contract and season revealed that the time-of-use/CPP contract was the most effective design at reducing the peak-demand.
- On average, the real-time contract did not bring the lowest average peak demand. This is explained by the fact that the real-time pricing induces the response when it is most needed, during a relatively small portion of all hours. Nevertheless, real-time prices were effective at reducing congestion peaks.

Variation of the Demand Response Impacts

Our review of the 17 pricing experiments reveals that the demand response impacts from different pilot programs vary widely due to the difference in the rate designs tested, use of enabling technologies, ownership of central air conditioning and more generally, due to the variations in sample design. To summarize the information, we have constructed a dataset of 28 observations where the impacts are grouped with respect to the rate designs and the existence of an enabling technology. Table 31 provides the mean impact estimates and the 95% confidence intervals associated with the mean values from this dataset.

Table 31- Summary Statistics for Impact Estimates

Rate Design	Number of Observations	Mean	95% Lower Bound	95% Upper Bound	Min	Max
TOU	5	0.04	0.03	0.06	0.02	0.06
TOU w/ Technology	4	0.26	0.21	0.30	0.21	0.32
PTR	3	0.13	0.08	0.18	0.09	0.18
CPP	8	0.17	0.13	0.20	0.12	0.25
CPP w/ Technology	8	0.36	0.27	0.44	0.16	0.51

Notes:

1- Confidence intervals are calculated assuming normal distribution of the impact estimates.

2- Xcel Energy pilot results are excluded from the summary statistics due to the role of self-selection bias, as reported in the study, in driving the large demand impacts.

3- CPP impact for Idaho is also excluded from the summary statistics since it is an outlier.

On average, TOU programs are associated with four percent reduction in peak usage, with a 95 percent confidence interval of three to six percent. CPP programs reduce peak usage by 17 percent on average with a 95 confidence interval of 13 to 20 percent. In the same fashion, CPP programs supported with enabling technologies reduce peak usage by 36 percent on average with a 95 confidence interval of 27 to 44 percent. Average peak reduction impacts associated with PTR and TOU supported with enabling technology programs are also provided in Table 31, however these numbers should be interpreted with caution due to small number of observations underlying the distributions. Nine out of twelve impact estimates with enabling technologies are tested on the customers with CAC ownership, so these impacts also capture impacts due to CAC ownership to some extent.

Our survey finds that in addition to a wide variation among the impact estimates across different rate designs, the impacts also vary widely among the experiments using the same time varying rate concepts. Differences in the rate designs tested and heterogeneity of the experimental designs emerge as the main drivers of this wide variation. It is also important to note that these impacts are induced by the price elasticities of the customers. In simple terms, demand impacts are obtained by the multiplication of the price elasticity of demand and the percent price change relative to the existing rate. Therefore, the variation in the price elasticities of the customers in different regions together with the differences in relative prices help explain this spread in the impact estimates from different programs. Substitution elasticities from the pilots reviewed in this paper ranges from -0.07 to -0.40 while the own price elasticities range from -0.02 to -0.10. Availability of the enabling technologies, ownership of central air conditioning and the type of the days examined (weekend vs. weekday) are some of the factors that lead to variations in the demand elasticities.

Another interesting question is how the impact estimates vary for different critical peak prices. To address this question, we have simulated the demand response to increasing levels of critical prices using the California SPP experiment data and the PRISM (Price Impact Simulation Model).

The PRISM[33] model predicts the changes in electricity usage that are induced by time-varying rates by utilizing the parameter estimates of a constant elasticity of substitution (CES) demand system[34]. This demand system consists of two equations. The substitution equation predicts the ratio of peak to off-peak quantities as a function of the ratio of peak to off-peak prices and other factors. The daily energy usage equation predicts the daily electricity usage as a function of daily price and other factors. Once the demand system is estimated, the resulting equations are solved to determine the changes in electricity usage associated with a time-varying rate. PRISM has the capability to predict these changes for peak and off-peak hours for both critical and non-critical peak days. Moreover, PRISM allows predictions to vary by other exogenous factor such as the saturation of central air conditioning and variations in climate. The model can be set to demonstrate these impacts on different customer types.

Since we would like to determine how the usage impacts vary as the critical prices are increased gradually, we have run the PRISM model using the data points provided in Table 32. To clarify how PRISM models the relationship between the prices and the percentage impact on load in a non-linear fashion, consider the following example. For the average customer, peak period energy usage decreases by 4% when the peak-price increases from \$0.13 per kWh to \$0.23 per kWh. However, peak period energy usage decreases by only 8% when the peak price is increased from \$0.13 per kWh to \$0.43 per kWh. This example demonstrates that the load impact increases by one-fold (rather than two-fold) when the price increases by two-fold. We can also observe the differences between customer types in their price-responsiveness from these response curves. For a given price increase, Non-CAC customers (without CAC ownership) are the least responsive group while CAC customers (with CAC Ownership) are the most responsive.

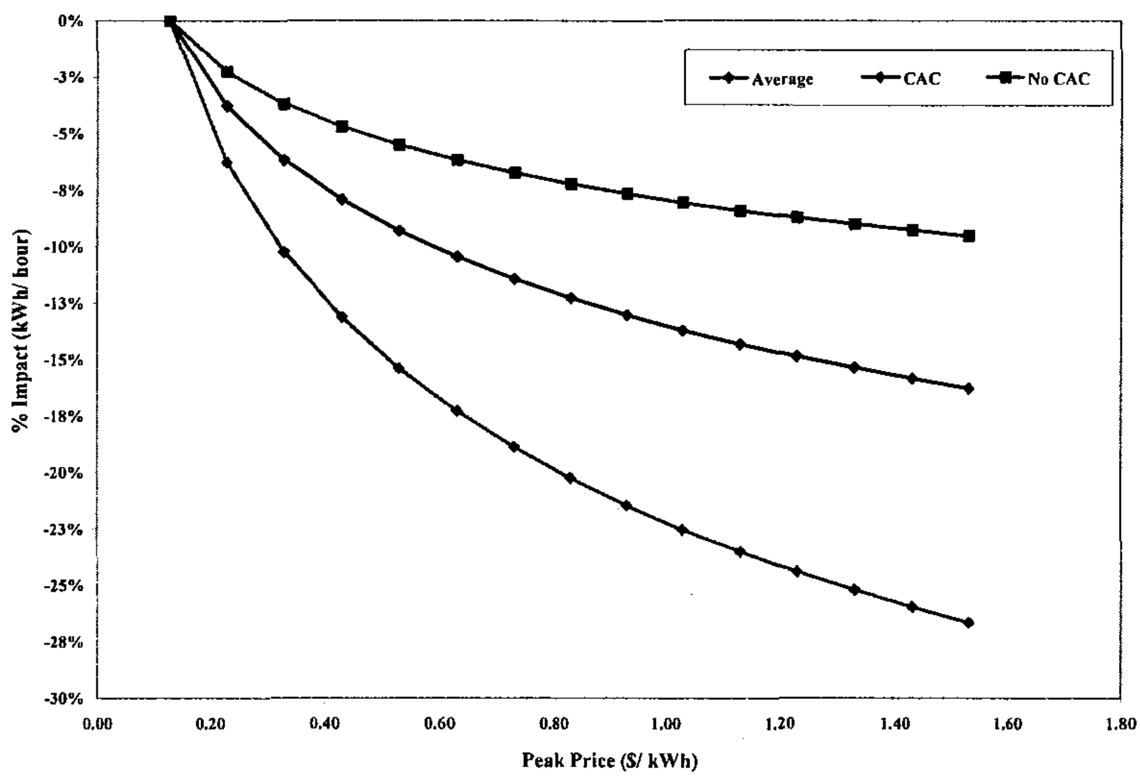
Table 32- PRISM Impact Simulation

[33] PRISM emerged from the data collected during the 2003-2005 California Statewide Pricing Pilot (SPP).

34 For the description of the CES model, see Charles River Associates, "Impact Evaluation of the California Statewide Pricing Pilot," March 2005.

	% Reduction in Quantity		
Critical Price (cents/kWh)	Average Customer	Customer w/ CAC	Customer w/o CAC
0.13	0.0%	0.0%	0.0%
0.23	-3.8%	-6.3%	-2.3%
0.33	-6.2%	-10.2%	-3.7%
0.43	-7.9%	-13.1%	-4.7%
0.53	-9.3%	-15.4%	-5.5%
0.63	-10.4%	-17.3%	-6.2%
0.73	-11.4%	-18.9%	-6.7%
0.83	-12.3%	-20.2%	-7.2%
0.93	-13.0%	-21.5%	-7.7%
1.03	-13.7%	-22.5%	-8.0%
1.13	-14.3%	-23.5%	-8.4%
1.23	-14.9%	-24.4%	-8.7%
1.33	-15.4%	-25.2%	-9.0%
1.43	-15.8%	-26.0%	-9.3%
1.53	-16.3%	-26.7%	-9.5%

Figure 2- Residential Customer Peak Response Curves on Critical Days



The response curves in Figure 2 demonstrate how the percent impact on peak period energy usage varies with the peak-period price on critical days. These curves show that the percentage impact on the peak period energy usage increases as prices increase, but at a decreasing rate. This non-linear relation between usage impacts and prices is reflected in the concave shape of the response curves.

CONCLUSIONS

This article reviews the most recent evidence on the effectiveness of residential demand response dynamic pricing programs in the United States and elsewhere. We find that demand responses vary from modest to substantial, largely depending on the time-varying rates used in the experiments and the availability of enabling technologies integrated into the experiment designs. Across the range of experiments studied, time-of-use rates induce a drop in peak demand that ranges between three to six percent and critical-peak pricing tariffs lead to a drop in peak demand of 13 to 20 percent. When accompanied with enabling technologies, the latter set of tariffs lead to a drop in peak demand in the 27 to 44 percent range. In summary, residential dynamic pricing designs can be effective demand side resources in reducing peak demand.

These results have important implications for the reliability and least cost operation of an electric power system facing ever increasing demand for power and surging capacity costs. Demand response programs that blend together customer education initiatives, enabling technology investments, and carefully designed time-varying rates can achieve demand impacts that can alleviate the pressure on the power system. Uncertainties involving the fuel prices and the form of a carbon pricing regime that is in the horizon emphasize the importance of the demand-side resources. Dynamic pricing regimes also incorporate some uncertainties such as the responsiveness of customers, cost of implementation and revenue impacts. However, these uncertainties can be addressed to a large extent by implementing pilot programs that produce invaluable insights for a full-scale deployment of the dynamic rates.

Table 31- Summary of the Experimental Tariffs from the Studies Reviewed

Study	Control Group Tariff	Applicable Period	Treatment Group Tariff	Applicable Period
California- Anaheim Peak Time Rebate Pricing Experiment	$0.0675/kWh $0.1102/kWh	Usage<=240kWh per month Usage>240kWh per month	**PTR/** Control group tariff **PTR/** $0.35/kWh rebate for each kWh reduction from baseline	All hours except 12a.m.- 6p.m. on CPP days 12a.m.- 6p.m. on CPP days
California- Statewide Pricing Pilot	$0.13/kWh	All hours	**TOU/** Off-peak: $0.09/kWh **TOU/** Peak: $0.22/kWh **CPP-F/** Off-peak: $0.09/kWh **CPP-F/** Peak: $0.22/kWh **CPP-F/** CPP: $0.59/kWh **CPP-V/** Off-peak: $0.10/kWh **CPP-V/** Peak: $0.22/kWh **CPP-V/** CPP: $0.65 /kWh	12a.m.- 2 p.m. and from 7 p.m. until 12a.m. weekdays, all day on weekends 2 p.m. to 7 p.m. weekdays 12a.m.- 2 p.m. and from 7 p.m. until 12a.m. weekdays, all day on weekends 2 p.m. to 7 p.m. weekdays 2 p.m. to 7 p.m. weekdays when called 12a.m.- 2 p.m. and from 7 p.m. until 12a.m. weekdays, all day on weekends 2 p.m. to 7 p.m. weekdays 2 or 5 hours during 2 p.m. to 7 p.m., weekdays when called
Florida- The Gulf Power Select Program	$0.057/kWh	All hours	**RST/** Off-peak: $0.027/kWh **RST/** Peak: $0.104/kWh **RSVP/** Off-peak: $0.035/kWh **RSVP/** Mid-peak: $0.046 /kWh **RSVP/** Peak: $0.093/kWh **RSVP/** CPP: $0.29/kWh	12 a.m.-12p.m. and 9p.m.-12a.m. 12p.m.- 9p.m. 12a.m.-6a.m. and 11p.m.-12a.m. 6a.m.-11a.m. and 8p.m.-11p.m. 11a.m.-8p.m. Assigned hours on CPP days
Idaho- Idaho Residential Pilot Program	$0.054/kWh $0.061/kWh	Usage<= 300 kWh per month Usage>300 kWh per month	**TOU/** Off-peak: $0.045/kWh **TOU/** Mid-peak: $0.061 /kWh **TOU/** On-peak: $ 0.083/kWh **CPP/** Non-CPP hours: $0.054/kWh **CPP/** CPP: $0.20/kWh	9p.m. to 7a.m. weekdays, all day on weekends 7a.m. to 1p.m. weekdays 1p.m. to 9p.m. weekdays All hours except CPP hours 5 p.m. to 9 p.m. on CPP days
Missouri- AmerenUE Residential TOU Pilot Study	-	-	**TOU/** Off-peak: $0.048/kWh **TOU/** Mid-peak: $0.075/kWh **TOU/** On-peak: $0.1831/kWh **CPP/** same as TOU except that there is a CPP component set at $0.30/kWh and peak price is decreased to $0.1675 /kWh	10p.m.–10a.m. weekdays, all day on weekends 10a.m.– 3p.m. and 7p.m.-10p.m. weekdays 3p.m. – 7p.m. weekdays CPP days when called, otherwise same as TOU

Table 31- (Cont'd) Summary of the Experimental Tariffs from the Studies Reviewed

Study	Control Group Tariff	Applicable Period	Treatment Group Tariff	Applicable Period
New Jersey- GPU Pilot	$0.12/kWh $0.153/kWh	Usage<=600kWh Usage>600kWh	**High-rate Design** CPP/ Off-peak: $0.065/kWh CPP/ Shoulder:$0.175/kWh CPP/ Peak:$0.30/kWh CPP/ Critical:$0.50/kWh **Low-rate Design** CPP/ Off-peak:$0.09/kWh CPP/ Shoulder:$0.125/kWh CPP/ Peak:$0.25/kWh CPP/ Critical:$0.50/kWh	1a.m.-8a.m. and 9p.m.-12p.m. weekdays, all day on weekends and holidays 9a.m.-2p.m. and 7p.m.-8p.m. weekdays 3p.m.-6p.m. weekdays When called during peak period 1a.m.-8a.m. and 9p.m.-12p.m. weekdays, all day on weekends and holidays 9a.m.-2p.m. and 7p.m.-8p.m. weekdays 3p.m.-6p.m. weekdays When called during peak period
New Jersey- PSE&G Residential Pilot Program	$0.087/kWh	All hours	CPP/ Night: $0.037/kWh CPP/ Peak: $0.24/kWh CPP/ CPP: $1.46/kWh	10 p.m.-9a.m. daily 1p.m.-6p.m. weekdays 1p.m.-6p.m. weekdays when called
Ontario/ Canada- Ontario Energy Board Smart Price Pilot	$0.058/kWh $0.067/kWh	Usage<= 600 kWh per month Usage>600 kWh per month	TOU/ Off-peak: $0.035/kWh TOU/ Mid-peak: $0.075/kWh TOU/ On-peak: $0.105/kWh CPP/ same as TOU except that there is a CPP component set at $0.30/kWh and off-peak price is decreased to $0.031/kWh PTR/ same as TOU with PTR at $0.30/kWh for each kWh reduction from the baseline	10 p.m.- 7 a.m. weekdays, all day on weekends and holidays 7 a.m.- 11 a.m. and 5 p.m.- 10 p.m. weekdays 11 a.m.- 5 p.m. weekdays CPP days when called, otherwise same as TOU CPP days when called, otherwise same as TOU
Washington - Olympic Peninsula Project	-	-	**Summer** CPP/ Off-peak:$0.05/kWh CPP/ On-peak:$0.135/kWh CPP/ Critical:$0.35/kWh **Fall/ Spring/ Winter** CPP/ Off-peak:$0.04119/kWh CPP/ On-peak:$0.1215/kWh CPP/ Critical:$0.35/kWh Fixed Price/ All hours:$0.081/kWh	9 am-6pm and 9pm-6am 6am-9am and 6pm-9pm When called 9am-3pm 3pm-9pm When called All hours

Table 32- Summary of the Experimental Elasticities from the Studies Reviewed

Pilot	Program	Substitution Elasticity	Own Price Elasticity	Cross Price Elasticity
California- Statewide Pricing Pilot	CPP-F	-0.087	-0.054 (daily)	-
	CPP-V/ Track A	-0.111	-0.027 (daily)	-
	CPP-V/ Track A	-	-0.043 (weekend daily)	-
	CPP-V/ Track C	-0.154 (*)	-0.044 (daily)	-
	CPP-V/ Track C	-	-0.041 (weekend daily)	-
Illinois- The Community Energy Cooperative's Energy-Smart Pricing Plan	RTP	-	-0.047 (Overall)	-
	RTP	-	-0.069 (Overall with AC cycling)	-
	RTP	-	-0.015 (Daytime)	-
	RTP	-	-0.026 (Late daytime/evening)	-
	RTP	-	-0.02 (Daytime+high price notification)	-
	RTP	-	-0.048 (Late daytime/evening+high price notification)	-
New Jersey- PSE&G Residential Pilot Program	CPP w/ CAC	-0.069	-	-
	CPP w/o CAC	-0.063	-	-
	CPP w/ Tech.	-0.125	-	-
New Jersey- GPU Pilot		**1st Month**		
	CPP w/ Tech.	-0.306 (Overall)	-	-
	CPP w/ Tech.	-0.155, -0.166 (Peak-shoulder)	-	-
	CPP w/ Tech.	-0.395, -0.356 (Peak-off-peak)	-	-
	CPP w/ Tech.	-0.191, -0.187 (Shoulder-off-peak)	-	-
		2nd Month		
	CPP w/ Tech.	-0.295 (Overall)	-	-
	CPP w/ Tech.	-0.055, -0.06 (Peak-shoulder)	-	-
	CPP w/ Tech.	-0.407, -0.366 (Peak-off-peak)	-	-
	CPP w/ Tech.	-0.178, -0.176 (Shoulder-off-peak)	-	-
New South Wales/ Australia- Energy Australia's Network Tariff Reform	TOU	-	-0.30 to -0.38	-0.07 (Peak to shoulder)
	TOU	-	-	-0.04 (Peak to off-peak)

(*) Elasticity of substitution for CPP-Track C customers is estimated to be -0.077 and excludes the impact of technology (-0.214). We calculated substitution elasticity including the impact of technology as -0.154 through simulation.

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IMPACT EVALUATION OF THE CALIFORNIA STATEWIDE PRICING PILOT

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Final Report

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1. Executive Summary

California experienced a major power crisis in its unregulated wholesale markets during 2000 and 2001. The crisis was exacerbated by the lack of dynamic pricing in retail markets, which would have given customers an incentive to lower loads during peak times. One of the unknowns in implementing dynamic pricing is whether and by how much customers would reduce peak loads in response to dynamic price signals.

To help address this uncertainty, California's three investor-owned utilities, in concert with the two regulatory commissions, conducted an experiment to test the impact of time-of-use (TOU) and dynamic pricing among residential and small commercial and industrial customers. The primary objectives of California's Statewide Pricing Pilot (SPP) were to:

- Estimate the average impact of time-varying rates on energy use by rate period and develop models that can be used to predict impacts under alternative pricing plans
- Determine customer preferences and market shares for time-varying rate options
- Evaluate the effectiveness of and customer perceptions about pilot features and educational materials.

This evaluation report addresses the first objective. A previous report presented preliminary impact estimates for selected pilot treatments from the initial summer of the pilot (2003). This report updates and significantly extends those results. It is a comprehensive, standalone document and there is no need to review the previous report. Any discrepancies between results presented previously and those presented here reflect methodological enhancements and, therefore, should be resolved in favor of the current report.

The SPP involved some 2,500 customers and ran from July 2003 to December 2004. Several different rate structures were tested. These included a traditional time-of-use rate (TOU), where price during the peak period was roughly 70 percent higher than the standard rate and about twice the value of the price during the off-peak period. The SPP also tested two varieties of critical peak pricing (CPP) tariffs, where the peak period price during a small number of critical days was roughly five times higher than the standard rate and about six times higher than the off-peak price. One CPP rate, CPP-F, had a fixed critical peak period and day-ahead notification. The other, CPP-V, had a variable peak period on critical days and day-of notification. CPP-V customers had the option of having an enabling technology installed free of charge to help facilitate demand response. The SPP also tested an information treatment that urged customers to reduce demand on critical days in the absence of time-varying price signals.

1. Executive Summary

1.1 METHODOLOGICAL OVERVIEW

Both the overall design of the SPP, as well as the evaluation approach underlying the results presented here, allow not only for estimation of the impact of the specific price levels tested in the SPP, but also for estimation of demand response for prices that were not explicitly used as part of this experiment. The experimental design included control groups that stayed on the standard tariff and treatment groups that were placed on new time-varying tariffs or information programs. The treatment groups for each tariff were divided into subgroups that faced different price levels so that statistical relationships between energy use by rate period and prices could be estimated.

These statistical relationships, referred to as demand models, were used to estimate the demand response impact for the average prices used in the SPP. Importantly, they can also be used to estimate the impact of other prices that are within a reasonable range of those tested, as illustrated in some of the figures presented later in this Executive Summary as well as in the report. Most of the demand models also allow one to adjust the magnitude of price responsiveness to account for variation in climate and the saturation of central air conditioning. Thus, demand response impact estimates can be developed for customer segments with characteristics that differ from those included in the experiment.

As noted above, the data used to estimate demand models includes information on both treatment and control customers. For treatment customers, information on energy use by rate period is available both before and after being placed on the new rate. This type of database allows one to separate the impact of the experimental treatments from the impact of other factors that might influence energy use, including self-selection bias.

The demand system estimated for each tariff consists of two equations. One equation predicts daily energy use as a function of daily price and other factors. The second equation predicts the share of daily energy use by rate period. This type of demand system is commonly used in empirical analysis of energy consumption. While the complexity of the experimental design has created numerous empirical challenges, these challenges have been addressed through careful application of widely accepted statistical methods.

1.2 RESIDENTIAL SECTOR SUMMARY

Three rate treatments were examined for residential customers; CPP-F, CPP-V and TOU. An information only treatment was also examined. The CPP-F and TOU rates were implemented among a statewide sample of customers. The sample size for the CPP-F treatment was much larger than for the TOU treatment and the results are more robust. The CPP-V rate was implemented only in the SDG&E service territory and the Information Only treatment in the PG&E service territory.

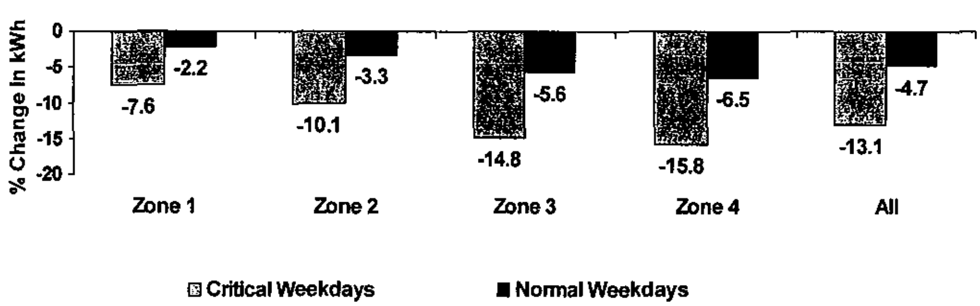
1.2.1 CPP-F Impacts

A key focus of the SPP was to assess the impact of dynamic tariffs. Estimated impacts vary on critical days (when the highest prices are in effect), normal weekdays (when lower peak prices are in effect) and weekends (which have the same prices as off-peak weekday periods).

Figure 1-1 summarizes the impact of the average CPP-F prices on energy use during the peak period on critical and normal weekdays. Statewide, the estimated average reduction in peak-period energy use on critical days was 13.1 percent. Impacts varied across climate zones, from a low of –7.6 percent in the relatively mild climate of zone 1 to a high of –15.8 percent in the hot climate of zone 4. The average impact on normal weekdays was -4.7 percent, with a range across climate zones from –2.2 percent to –6.5 percent.

The statewide impact estimate of -13.1 percent has a 95 percent confidence band of +/- 1 percentage point. This means that there is a 95 percent probability that the actual reduction in peak-period energy use on critical days based on average SPP prices would fall between 12.1 and 14.1 percent.

Figure 1-1
Percent Change In Residential Peak-Period Energy Use
(Avg CPP-F Prices/Avg 2003/2004 Weather)

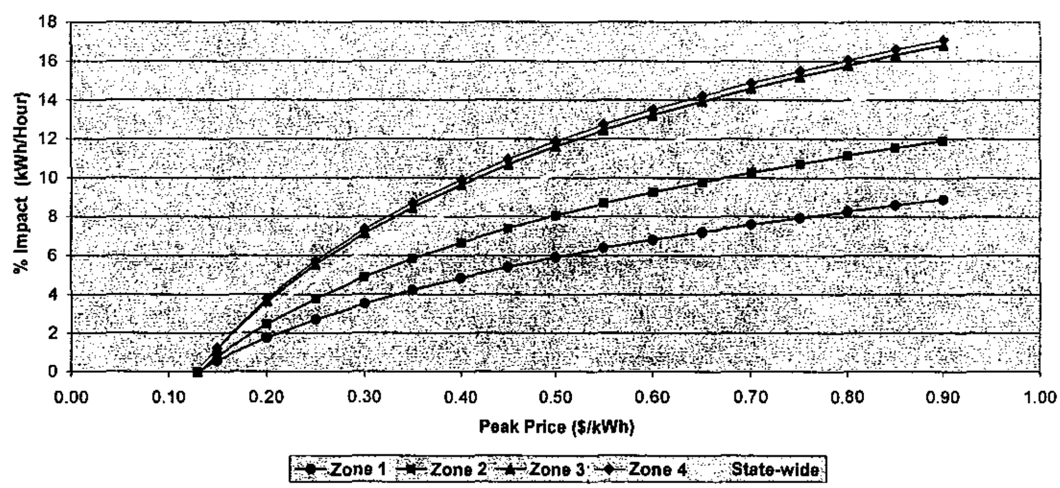


Other key findings for the CPP-F rate include:

- Differences in peak-period reductions on critical days across the two summers, 2003 and 2004, were not statistically significant
- Differences in impacts across critical days when two or three critical days are called in a row (as might occur during a heat wave) were not statistically significant
- Average impacts on critical days were greater during the hot summer months of July through September (the "inner summer") than during the milder months of May, June and October (the "outer summer")

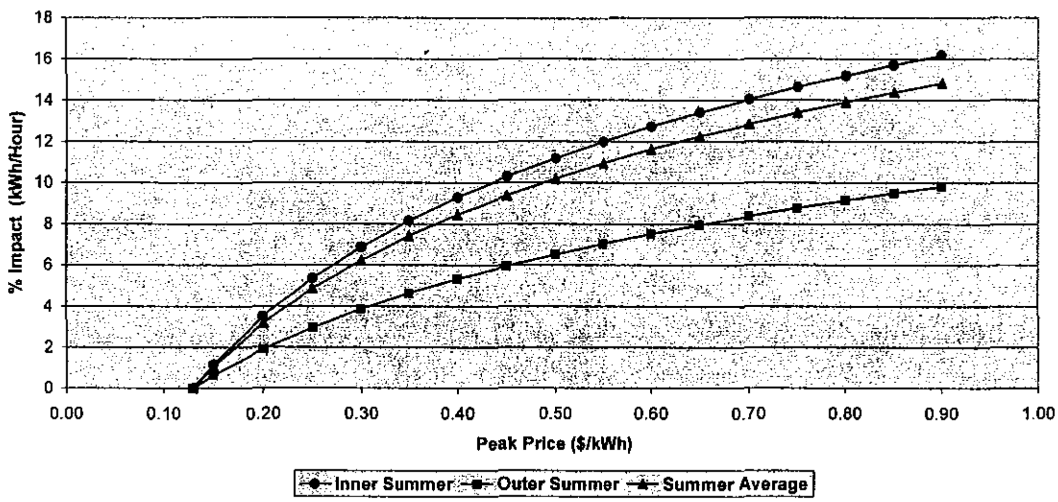
- Households with central air conditioning were more price responsive and produced greater absolute and percentage reductions in peak-period energy use than did households without air conditioning
- Demand response impacts were lower in the winter than in the summer, and lower during the milder winter months of November, March and April (the "outer winter") than during the colder months of December, January and February (the "inner winter").
- There was essentially no change in total energy use across the entire year based on average SPP prices. That is, the reduction in energy use during high-price periods was almost exactly offset by increases in energy use during of-peak periods.

Figure 1-2
Percent Reduction in Peak-Period Energy Use on Critical Days
Average Summer, 2003/04



As previously mentioned, one of the primary advantages to developing demand models is to estimate the impact of prices that were not specifically tested in the SPP. Figures 1-2 and 1-3 show how the percent reduction in peak-period energy use on critical days varies with changes in the peak-period price on critical days (when everything else is held constant). The curves indicate that the reduction in peak-period energy use increases as prices increase, but at a diminishing rate. Figure 1-2 shows that reductions are greater in percentage terms (and even greater in absolute terms) in hotter climate zones (where air conditioning saturations are high) than in cooler zones. Figure 1-3 shows that reductions are greater in the inner summer months of July, August and September than in the outer summer months of May, June and October. We believe the greater responsiveness in the inner summer is due primarily to the influence of air conditioning.

Figure 1-3
Percent Reduction in Peak-Period Energy Use on Critical Days by Season



1.2.2 TOU Impacts

The reduction in peak-period energy use resulting from TOU rates in the inner summer of 2003 equaled –5.9 percent. This 2003 value is comparable to the estimate for the CPP-F tariff on normal weekdays when prices were similar to those for the TOU treatment. However, in 2004, the TOU rate impact almost completely disappeared (-0.6 percent). TOU winter impacts are comparable to the normal weekday winter impacts for the CPP-F rate.

Drawing firm conclusions about the impact of TOU rates from the SPP is somewhat complicated by the fact that the TOU sample sizes were small relative to the CPP-F sample sizes. Small sample sizes are more subject to influence by outliers and changes in the sample composition over time. Further complicating the estimation of the daily energy equation is that variation in daily prices over time is quite small, which makes it difficult to obtain precise estimates of daily price responsiveness. In short, there are reasons to take the analysis of the TOU rate treatment with a "grain of salt." Indeed, an argument could be made that the normal weekday elasticities from the CPP-F treatment may be better predictors of the influence of TOU rates on energy demand than are the TOU price elasticity estimates.

On the other hand, if the TOU results are accurate, they have very important policy implications, since they suggest that the relatively modest TOU prices tested in this experiment do not have sustainable impacts.

1.2.3 CPP-V Impacts

The residential CPP-V rate was tested among two different populations, both within the SDG&E service territory.

Track A customers were drawn from a population of customers with average summer energy use exceeding 600 kWh per month. The saturation of central air conditioning among the Track A treatment group was roughly 80 percent, much higher than among the general population, and average income was also much higher. Track A customers were given a choice of having an enabling technology installed free of charge to facilitate demand response. About two-thirds of participants took one of three technology options and about half of those selected a smart thermostat.

Track C customers were recruited from a sample of customers that had previously volunteered for the AB970 Smart Thermostat pilot. All Track C customers had smart thermostats and central air conditioning.

Key findings for the CPP-V rate treatments include:

- The reduction in peak-period energy use for Track A customers on critical days equaled almost 16 percent, which is about 25 percent higher than the CPP-F rate average

- The peak-period reduction for the Track C treatment equaled roughly 27 percent. About two-thirds of this reduction can be attributed to the enabling technology and the remainder is attributable to price-induced behavioral changes

Although comparisons between Track A and Track C CPP-V treatments and between the CPP-V and CPP-F treatments must be made carefully due to differences in sample composition, the Track C results suggest that impacts are significantly larger with enabling technology than without it. The 27 percent average impact for the Track C, CPP-V treatment is roughly double the 13 percent impact for the CPP-F rate for the average summer. It is also substantially larger than the Track A, CPP-V treatment impact, where only some customers took advantage of the technology offer.

1.2.4 Information Only Impacts

The Information Only treatment was included primarily as a crosscheck on the results of the CPP-F rate treatment. Specifically, the purpose was to determine whether simply appealing for a reduction in energy use on critical days might produce significant impacts even in the absence of any price incentive. Information Only customers were given educational material regarding how to reduce loads during peak periods, and they were notified in the same manner as were CPP-F customers when critical days were called. However, participants were not placed on time varying rates.

The Information Only treatment was implemented in two climate zones in the PG&E service territory. In one of the two zones in 2003, demand response was statistically significant while in the other zone it was not. In 2004, there was no evidence of any response in either zone. At a minimum, one can conclude that demand response in the absence of a price signal is not sustainable. Furthermore, we believe it is not unreasonable to consider the 2003 impact for a single climate zone to be an anomaly and to conclude that there is no clear evidence from the SPP of any significant impact from an appeal to reduce energy use on critical days in the absence of a price signal.

1.2.5 Residential Summary

Table 1-1 summarizes the key findings with regard to reductions in peak-period energy use resulting from the various tariff options tested in the SPP.

The most robust and generalizable estimates from the SPP are for the CPP-F rate. TOU rate impacts vary across years and are suspect due to sample size limitations and other factors. We recommend using the CPP-F models to predict TOU impacts. Although the Track C, CPP-V results are more difficult to generalize to the overall population, they provide useful estimates of the incremental impact of prices and enabling technology.

Table 1-1 Summary of Average Peak-Period Impacts by Treatment Type for Residential Customers				
Treatment	**Day Type**	**Avg. Price (¢/kWh)**[1]	**Impacts**	**Comments**
Track A CPP-F	**Critical Weekday**	P = 59 OP = 9 D = 23 C = 13	-13.1% average summer -14.4% inner summer -8.1% outer summer	No statistically significant difference for inner summer between 2003 and 2004 (differences across the two years can not be estimated for the outer summer or the average summer)
	Normal Weekday	P = 22 OP = 9 D = 12 C = 13	-4.7% average summer -5.5% inner summer -2.3% outer summer	Difference between critical & normal days is primarily due to price differences and secondarily to differences in weather
Track A TOU	**All Weekdays**	P = 22 OP = 10 D = 13 C = 13	-5.9% inner summer 2003 -0.6% inner summer 2004 -4.2% outer summer 2003/04	Results are suspect because of the small sample size and observed variation in underlying model coefficients across the two summers. Recommend using normal weekday CPP-F model to predict for TOU rate.
Track A CPP-V	**Critical Weekday**	P = 65 OP = 10 D = 23 C= 14	-15.8% average summer 2004 Represents average across households with and without enabling technology—could not separate price & technology impacts	Not directly comparable to CPP-F results due to differences in population (CAC saturation for CPP-V treatment group twice that of CPP-F; CPP-V average income much higher; 2/3 of CPP-V customers had enabling tech.; all households located in SDG&E service territory)
	Normal Weekday	P = 24 OP = 10 D = 14 C = 14	-6.7% average summer 2004	See above comments about population differences
Track C CPP-V	**Critical Weekday**	Same as for Track A	-27.2% combined tech & price impact for average summer 2003/04 -16.9% impact for tech only -11.9% incremental impact of price over & above tech impact	Not directly comparable to Track A results due to population differences (All Track C customers are single family households with CAC located in SDG&E service territory). Some evidence that impacts fell between 2003 & 2004
	Normal Weekday	Same as for Track A	-4.5% average summer 2003/04	See above comments about population differences
Track A Info Only	**Critical Weekday**	13 for all periods	Statistically significant response in one of two climate zones in 2003. No response in 2004.	Analysis provides no evidence of sustainable response in the absence of price signals.

It is interesting to compare the results obtained from the SPP with those that have been found elsewhere. There have been dozens of studies of the impact of time-varying rates conducted over the years, many of them quite dated.[2] Very few previous studies

[1] P = peak period price; OP = off-peak price; D = daily price; C = control group price.

[2] Chris S. King and Sanjoy Chatterjee. *Predicting California Demand Response.* Public Utilities Fortnightly, July 1, 2003.

examined dynamic rates, which was a key focus of the SPP. Making comparisons across studies is very difficult because of differences in methodology, differences in the characteristics of underlying populations and differences in price levels and other factors. Ignoring such complexities, a simple comparison shows that the SPP estimates of price responsiveness in California are at the low end of the range reported in the literature.

One study, conducted in the early 1980s by the Electric Power Research Institute,[3] allows for a more careful comparison between the SPP results and estimates based on several of the well-designed TOU rate experiments that were conducted in the late 1970s. The EPRI study used a similar model specification to the one used here so that we were able to estimate the impact of SPP prices using the price responsiveness measures from the EPRI study. Using these earlier model parameters along with average SPP prices, the estimated peak-period reduction on critical days is roughly 70 percent greater than the estimated value from the SPP (i.e., -22.5 percent versus -13.1 percent).

Based on these comparisons, it would appear that price responsiveness in California today is less than it was in California and elsewhere a quarter century ago. This is not surprising in light of the significant conservation and load management programs that were implemented in the last 25 years. Actions taken by many consumers following the energy crises of 2000 and 2001 may also have reduced the ability or willingness of California's customers to further reduce energy use. Nevertheless, it is also very clear from the results presented here that there still remains a significant amount of demand response that can be achieved through TOU and dynamic pricing.

1.3 COMMERCIAL AND INDUSTRIAL SECTOR SUMMARY

CPP-V and TOU tariffs were also tested among C&I customers. All treatments were implemented in the SCE service territory. The C&I population was segmented into two groups, customers with peak demands less than 20 kW (LT20) and customers with peak demands between 20 and 200 kW (GT20). The CPP-V tariff was implemented among two population samples. The Track A sample was recruited from the general population while the Track C sample was drawn from a pre-existing Smart Thermostat pilot. All Track C customers had central air conditioning and smart thermostats. Most Track A customers had central air conditioning but only about half selected the smart thermostat technology option. In light of these and other differences, direct comparisons between Track A and Track C results must be made carefully.

For the Track A, CPP-V treatment, key findings include:

[3] Results from the EPRI study are summarized in Douglas Caves, Laurits Christensen and Joseph Herriges, *Consistency of Residential Customer Response in Time-of-Use Electricity Pricing Experiments.* Journal of Econometrics 16 (1984) 179-203, North-Holland.

- LT20 customers had a very small but statistically significant demand response, with the average peak-period reduction on critical weekdays equal to 6.0 percent
- The peak-period reduction on normal weekdays for LT20 customers was roughly 1.5 percent
- Although the percent reduction in peak-period energy use was much smaller among LT20 customers than among residential customers on the CPP-F rate, the absolute reduction was slightly larger because average energy use for LT20 customers was about three times larger than for residential customers
- GT20 customers showed a larger percent reduction in peak-period energy use on critical weekdays (-9.1 percent) than did LT20 customers
- Reductions in peak-period energy use on normal weekdays for GT20 customers equaled 2.4 percent
- The absolute size of the reduction in peak-period energy use for GT20 customers was roughly 10 times larger than for LT20 customers, due primarily to the fact that average energy use for GT20 customers was much larger than for LT20 customers and secondarily to the fact that GT20 price responsiveness was greater than it was for LT20 customers.

Key findings for the Track C, CPP-V treatment include:

- LT20 customers reduced peak-period energy use on critical weekdays by 14.3 percent. All of this reduction is attributable to the enabling technology. That is, this customer segment did not have any incremental price response.
- GT20 customers reduced peak-period energy use on critical weekdays by 13.8 percent. Roughly 80 percent of this reduction is attributable to the enabling technology.

For the C&I TOU rate treatment, demand response and impacts varied significantly between summer 2003 and summer 2004. In 2003, price was not statistically significant for the LT20 customer segment. However, price was significant in 2004 and the estimated reduction in peak-period energy use equaled almost 7 percent. Price was statistically significant in both summers for the GT20 segment. Peak period impacts in 2003 equaled –4.0 percent and in 2004 equaled –8.6 percent. These results should be viewed cautiously, however, in light of the small sample size and significant variation in the underlying model coefficients across summers.

Table 1-2 summarizes the key findings for the C&I analysis. The Track C, CPP-V results suggest that technology could have a relatively significant influence on demand response in the C&I sector, although this population is not representative of the overall population of C&I customers. Price responsiveness among the smallest segment (LT20) is quite small in most instances. Responsiveness is greater for GT20 customers than it is for LT20 customers.

Table 1-2 Summary of Average Peak-Period Impacts by Treatment Type for C&I Customers				
Treatment/ Customer Segment	**Day Type**	**Avg. Price (¢/kWh)**	**Impacts**	**Comments**
Track A TOU LT20	**All Weekdays**	P = 28 OP = 12 D = 18 C = 18	-0.3% in 2003 -6.8% in 2004	The 2003 value is not statistically significant. Small sample size and variation in underlying model coefficients across summers suggest estimates may be suspect. Recommend using normal weekday CPP-F model to predict for TOU rate.
Track A TOU GT20	**All Weekdays**	P = 23 OP = 12 D = 16 C = 15	-3.9% in 2003 -8.6% in 2004	The difference between 2003 and 2004 is statistically significant. Same caveat as described above for LT20 customers.
Track A CPP-V LT20	**Critical Weekday**	P = 81 OP = 12 D = 30 C = 17	-6.1% in 2004	This treatment was not implemented in 2003 Price responsiveness measure is small but statistically significant
	Normal Weekday	P = 20 OP = 12 D = 15 C = 17	-1.5% in 2004	Same comments as above
Track A CPP-V GT20	**Critical Weekday**	P = 66 OP = 11 D = 24 C = 15	-9.1% in 2004	This treatment was not implemented in 2003 This segment is more price responsive than LT20 customers
	Normal Weekday	P = 18 OP = 12 D = 14 C = 15	-2.4% in 2004	Same comments as above
Track C CPP-V LT20	**Critical Weekday**	P = 87 OP = 12 D = 33 C = 18	-14.3% combined tech & price impact for average summer 2003/04 -18.2% for tech alone +4.5% incremental impact of price over & above tech impact	The tech only impact is higher than the combined price/tech impact, indicating that price does not provide any incremental impact for this customer segment
	Normal Weekday	P = 21 OP = 12 D = 16 C = 18	+1.1 in average summer 2003/04	The estimate is not statistically significant. Additional evidence that this customer segment is not price responsive.
Track C CPP-V GT20	**Critical Weekday**	P = 71 OP = 11 D = 24 C = 15	-13.8% combined tech & price impact for average summer 2003/04 -11.0% for tech alone -3.2% incremental impact of price over & above tech impact	Incremental impact of price over technology declined by roughly 75% between 2003 and 2004 GT20 participants use significantly less electricity on average than the average control group
	Normal Weekday	P = 19 OP = 11 D = 14 C = 15	-0.9% in average summer 2003/04	Same comments as above

2. Background and Overview

2.1 INTRODUCTION

One of the lessons gleaned from California's energy crisis in 2000/2001 is that the lack of demand response in retail markets makes it very difficult to equilibrate wholesale markets at reasonable prices.[4] Studies have shown that economic efficiency in the allocation of scarce capital, fuel and labor resources can be improved by introducing demand response in retail markets. One method for introducing demand response in retail markets is time-varying pricing. With this in mind, the California Public Utilities Commission (CPUC) initiated a proceeding in July 2002 designed to introduce demand response in California's power market.[5]

As part of this proceeding, three working groups were charged with developing specific tariff proposals to achieve increased demand response in the state. The mission of Working Group 3 (WG3) was to develop a dynamic tariff (or set of tariffs) for residential and small commercial customers with demands less than 200 kW. WG3 included representatives from the state's three investor-owned utilities[6], two regulatory commissions[7], equipment vendors, The Utility Reform Network (TURN) and other interested parties.

In support of the WG3 deliberations, Charles River Associates (CRA) conducted a preliminary analysis of the potential benefits of a variety of time-differentiated rates at Pacific Gas & Electric Company (PG&E). The analysis included static time-of-use (TOU) rates and dynamic rates where high price signals are passed through to consumers on selected days when supply is constrained, the timing of which is unknown. The analysis showed a wide range of potential benefits from the implementation of dynamic pricing at PG&E, with the lower end being $561 million and the high end being $2,637 million. Incremental metering and billing costs associated with the provision of dynamic pricing were estimated at about a billion dollars.[8] Consequently, there is a wide range in estimates of the potential net-benefits of dynamic pricing, depending upon assumptions about meter and rate deployment strategy and costs, the level of customer demand response and the magnitude of avoided energy and capacity costs. Analysis also indicated that conducting an experiment with a few thousand customers could significantly reduce uncertainty in the net benefit estimates.

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4 James L. Sweeney, The California Electricity Crisis, Hoover Institution Press, 2002.

5 Order Instituting Rulemaking on policies and practices for advanced metering, demand response and dynamic pricing, CPUC R. 02-06-001.

6 Pacific Gas & Electric (PG&E), San Diego Gas & Electric (SDG&E) and Southern California Edison (SCE).

7 The CPUC and the California Energy Commission (CEC).

8 This cost estimate was very preliminary and is reported here for illustrative purposes only. All three of the utilities involved in the SPP have developed much more refined cost estimates as part of the ongoing AMI proceeding.

Based in part on this preliminary analysis, WG3 recommended on December 10, 2002 that the state conduct a carefully designed pricing experiment with different tariff options prior to making a decision on full-scale deployment of the automated metering infrastructure required to support such time-varying rates.[9] A decision was made to implement a statewide experiment rather than utility-specific experiments to better leverage scarce budget resources and also to ensure consistency in results across the state. The CPUC approved the experiment, now called the Statewide Pricing Pilot (SPP), on March 14, 2003.[10]

The SPP has three primary objectives:

- Estimate the average impact of time-varying rates on energy use by rate period and develop models that can be used to predict impacts under alternative pricing plans
- Determine customer preferences for tariff attributes and market shares for specific TOU and dynamic tariffs, control technologies and information treatments under alternative deployment strategies
- Evaluate the effectiveness of and customer perceptions of specific pilot features and materials, including enrollment and education material, bill formats, web information, and tariff features.

This report primarily addresses the first objective. Separate reports address the second and third objectives. A report summarizing the pilot results for the first summer of the experiment was issued on August 9, 2004 (and posted in October, 2004).[11] The results presented in the Summer 2003 Report did not cover all SPP treatments and covered only the initial summer period. This report updates and extends those findings for all treatments. To the extent that there are differences between the results presented in the Summer 2003 Report and those contained in this report, the results presented here should be used.

The tariffs tested in the SPP included a traditional TOU rate and two dynamic pricing rates. The dynamic rates included a critical-peak pricing (CPP) element that involved a substantially higher peak price (about 50 to 75 cents/kWh) for 15 days of the year and a standard TOU rate on all other days. One type of CPP rate (CPP-F) featured a fixed peak period on both critical and non-critical days and day-ahead customer notification for critical day events. The peak period for residential customers was between 2 pm and 7 pm weekday afternoons and the peak period for commercial and industrial customers

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9 Report of Working Group 3 to Working Group 1, R.-2-06-001. Proposed Pilot Projects and Market Research to Asses the Potential for Deployment of Dynamic Tariffs for Residential and Small Commercial Customers. Version 5, December 10, 2002.

10 Decision 03-03-036, Interim Opinion in Phase 1 adopting pilot program for residential and small commercial customers.

11 Charles River Associates, Inc. *Statewide Pricing Pilot, Summer 2003 Impact Analysis.* August 9, 2004, published October 11, 2003. Hereafter referred to as the Summer 2003 Report.

was from noon to 6 pm on weekdays. The other type of CPP rate (CPP-V) featured a variable-length peak period on critical days, which could be called on the day of a critical event. All SPP rates were seasonally differentiated, with summer running from May through October, inclusive, for residential customers and from the first Sunday in June through the first Sunday in October for commercial and industrial customers.

In addition to the rate treatments described above, an "Information Only" treatment was also tested for residential customers. This treatment involved notifying customers on critical days and asking them to avoid energy use during the peak period. However, prices were the same on critical days as they were on all other days and customers did not face time-varying prices on any day.

Residential customers in the SPP were segmented into four climate zones and commercial/industrial customers into two size strata, those with peak demands less than 20 kW (LT20) and those with peak demands between 20 and 200 kW (GT20). Residential CPP-F and TOU customers were drawn from the service territories of all three participating utilities (PG&E, SDG&E and SCE) while commercial/industrial customers were drawn exclusively from the SCE population. The residential CPP-V tariff was deployed exclusively in the SDG&E service territory and the Information Only tariff was implemented only in the PG&E service territory.

SPP customers were divided into three tracks:

- Track A represented the general population of customers in the state.
- Track B represented the population of relatively low-income customers living in the vicinity of two power plants in the Hunters Point/Potrero division of San Francisco and a control group of customers in the city of Richmond.[12]
- Track C represented the population of customers who had previously volunteered to be in the AB970 Smart Thermostat pilot program in the SCE (small commercial and industrial customers only) and SDG&E (residential customers only) service areas.

The remainder of this section discusses rate design, sample design and customer enrollment issues. Section 3 summarizes the analytical methods and data that were used to estimate the energy and demand impacts attributable to the SPP treatments. Section 4 summarizes the demand modeling and impact evaluation results for the residential CPP-F tariff. Section 5 focuses on the residential TOU tariff and Section 6 on the residential CPP-V rate treatment. Section 7 presents the findings associated with the C&I treatments, which include both TOU and CPP-V tariffs. A glossary of technical terms is contained at the end of this report. Numerous appendices, presented in a

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12 Results from the Track B analysis are contained in a separate report produced by San Francisco Community Power, the contractor that implemented and evaluated the Track B treatments. See *Statewide Pricing Pilot—Track B: Evaluation of Community-Based Enhanced Information Treatment*, Draft Final Report, March 8, 2005.

separate volume, contain a wide variety of technical details as well as the regression results underlying the information presented in subsequent sections.

2.2 RATE DESIGN

The specific tariffs that were tested in the SPP reflect compromises among WG3 members concerning the rate options that it would be desirable to explore, numerous analytical complexities, historical differences across service territories, and several political realities.

2.2.1 Customer Protection Constraints

The CPUC placed a number of constraints on the rate design process in order to address the concerns of various constituencies within WG3. Specifically, the experimental rates were required to satisfy three constraints:

- be revenue neutral for the class-average customer over a calendar year, in the absence of any change in the customer's load shape,
- not change the bill of low and high users by more than 5 percent in either direction, in the absence of any change in the load shape, and
- provide customers with an opportunity to reduce their bills by 10 percent if they reduced or shifted peak usage by 30 percent.

An additional design constraint, suggested by one of PG&E's rate analysts, was to lower bills when price ratios are high and raise bills when price ratios are low, in order to minimize adverse bill impacts for low and high users. Condition (a) was satisfied by placing customers on a high price ratio in the summer and a low price ratio in winter. The rates are revenue neutral on an annual basis, but not on a seasonal basis. The other conditions were satisfied by testing a variety of price ratios.

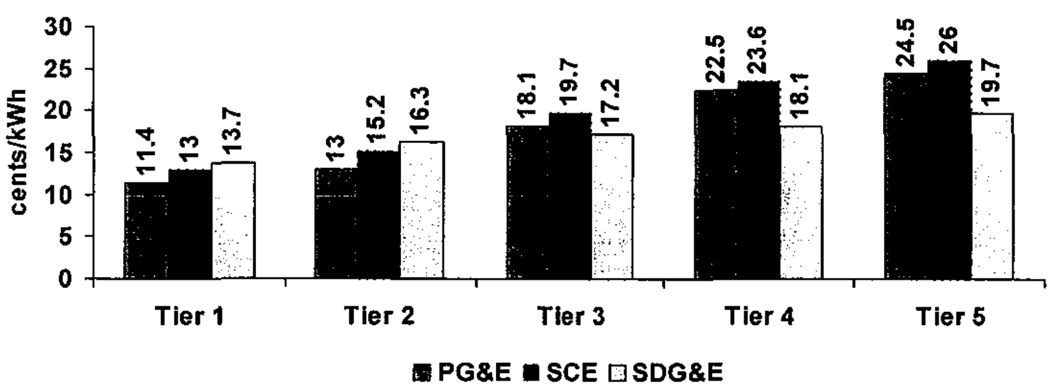
Finally, it is important to note that low-income households in California qualify for a 20 percent discount on their electricity bill under a program called CARE. The maximum eligible income for a CARE household can be no higher than $23,000 with one or two persons in the household; and no higher than $43,500 for a household with six persons. The specific details regarding how the 20 percent CARE discount is implemented varies by utility.

2.2.2 Experimental Considerations

The experimental rates were designed to allow estimation of models of the demand for energy by time-of-use period. Demand models allow for estimation of rate impacts for prices that differ from the specific ones used in the experiment. Each time-varying rate consists of two pricing periods, peak and off-peak. In order to facilitate estimation of demand models, two rate levels were created for each treatment group. When combined with the non-time varying rate for the control group, this yields three price points along the demand curve for energy use in each rate period.

Another rate-related complication was the existence of different base rates across the three utilities. The average prices, expressed in cents/kWh, during the summer of 2003 were 12.7 for PG&E and, rounded, 14.1 for both SDG&E and SCE.[13] As shown in Figure 2-1, the inverted five-tier rate structure differed across utilities. SDG&E customers started out with a higher price in Tier 1 but their prices didn't rise as steeply as they did for PG&E and SCE customers. Thus, customers in SDG&E's service territory paid slightly less than 20 ¢/kWh for Tier 5 usage whereas Tier 5 customers in PG&E's service area paid roughly 24.5 ¢/kWh and in Edison's they paid 26 ¢/kWh.[14]

Figure 2-1
Marginal Prices For Control Group Customers
At Start Of Treatment Period
(Summer 2003)



In developing rates for each utility, a decision was made to expose customers to consistent price differentials by time-of-day while maintaining the differences in the underlying rates across utilities. This approach applies a set of time-varying surcharges and discounts on top of the existing rate structure of each utility. The surcharges and discounts were identical across utilities, causing the effective TOU and CPP prices to differ by small amounts because of the differences in the underlying rates. This approach, which preserved the inverted character of the underlying rate structure, was chosen over an alternative approach that would have used a flat base rate for all

13 Prices have changed over the course of the pilot, more for some utilities than others. The prices presented here represent a snap shot in time and are for illustrative purposes only.

14 Edison's rates fell shortly after the pilot started, especially the Tier 5 marginal price. All tariff changes that were made by each utility during the course of the experiment were passed through to both treatment and control customers so rates varied over time.

consumers, with a time-varying rate structure applying to treatment customers. The primary disadvantage of the second approach is that it would have provided a substantial bill discount to high-use customers relative to low-use customers. As such, many high-use customers would have displayed a strong preference for the time-varying rate because it would have lowered their average rate even in the absence of changing their usage patterns or levels. In addition, the chosen approach automatically reflected changes in the underlying base rates that occurred during the experiment due to the normal course of business by each utility. The alternative approach would have required filing new experimental tariffs every time the underlying tariff changed and was not pursued for this and other reasons.

Given the complex nature of customer bills, customers were provided with a summary sheet showing (a) how much electricity they used by pricing period during the billing cycle, (b) how much they paid for it and (c) the implicit price for each period, expressed in cents per kWh. At the beginning of the experiment, customers were also provided a "shadow bill" that projected their likely electric bill on the experimental tariff during the summer and winter months and compared it with what their bill would have been had they stayed on their existing tariff under different assumptions about the magnitude of load shifting. Customers were provided with another shadow bill after having been in the experiment for twelve months. Customers were given the option of requesting a shadow bill anytime during the experiment. Appendix 1 contains an example of a filed tariff, a summary sheet and a shadow bill.

2.2.3 Critical Peak Dispatch

For the CPP-F and CPP-V tariffs, decisions concerning when to call critical days were based on a variety of criteria. First, about half the time, CPP-F and CPP-V rates were dispatched simultaneously. Second, for residential CPP-V Track C customers, the length of the dispatch period on critical event days was either two hours or five hours. For C&I, CPP-V customers, two, four and five hour dispatch periods were implemented. A total of 12 events were called for each CPP rate treatment in the summer months (May to October) and three were called in the winter. Thus, a total of 27 critical days were called for customers who stayed in the pilot for the entire treatment period. Critical days were chosen based on weather forecasts, system reliability conditions, the need to have a total of 12 days in the summer and to have a variety of days in the week.

In the summer of 2003, all critical events were single days. That is, events were never called on contiguous days. Following this initial period, concerns arose about whether behavioral response to critical day prices would change if events were called on consecutive days, such as might occur during a heat wave. In order to investigate this issue, in the summer of 2004, three critical events involving two or more consecutive days were called. One two-day event was called and two three-day events were called in 2004.

Table 2-1 summarizes the critical events that occurred for each treatment group throughout the pilot. The numbers in each cell indicate the timing and duration of each critical event. All CPP-F events ran for the entire peak period on critical days. CPP-V events varied with respect to start time and duration.

Table 2-1
Critical Peak Pricing Event Summary

Critical Event Date	Residential CPP-F					Residential CPP-V		C&I CPP-V	
	Zone 1	Zone 2	Zone 3	Zone 4	Track B	Track A	Track C	Track A	Track C
07/10/03	2-7	2-7	2-7	2-7	n/a	n/a	2-4	n/a	2-6
07/17/03	2-7	2-7	2-7	2-7	n/a	n/a	2-4	n/a	2-4
07/28/03	n/a	2-7	2-7	2-7	n/a	n/a	2-7	n/a	1-6
08/08/03	n/a	2-7	2-7	2-7	n/a	n/a	3-5	n/a	3-5
08/14/03	n/a	n/a	n/a	N/a	n/a	n/a	n/a	n/a	1-6
08/15/03	n/a	n/a	n/a	N/a	n/a	n/a	2-7	n/a	2-6
08/18/03	2-7	2-7	2-7	2-7	n/a	n/a	n/a	n/a	n/a
08/27/03	2-7	2-7	2-7	2-7	n/a	n/a	4-6	n/a	4-6
09/03/03	2-7	2-7	2-7	2-7	n/a	n/a	2-7	n/a	1-6
09/11/03	2-7	n/a	n/a	N/a	n/a	n/a	n/a	n/a	1-6
09/12/03	2-7	2-7	2-7	2-7	2-7	n/a	2-7	n/a	4-6
09/18/03	2-7	n/a	n/a	N/a	2-7	n/a	n/a	n/a	n/a
09/19/03	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	4-6
09/22/03	2-7	2-7	2-7	2-7	n/a	n/a	n/a	n/a	n/a
09/29/03	n/a	n/a	n/a	n/a	n/a	n/a	2-7	n/a	1-6
10/09/03	2-7	2-7	2-7	2-7	2-7	n/a	3-5	n/a	n/a
10/14/03	2-7	2-7	2-7	2-7	2-7	n/a	2-7	n/a	n/a
10/20/03	2-7	2-7	2-7	2-7	2-7	n/a	3-5	n/a	n/a
10/21/03	n/a	n/a	n/a	n/a	2-7	n/a	n/a	n/a	n/a
01/06/04	2-7	2-7	2-7	2-7	2-7	n/a	2-7	n/a	1-6
01/26/04	2-7	2-7	2-7	2-7	2-7	n/a	2-7	n/a	1-6
01/27/04	n/a	n/a	n/a	n/a	2-7	n/a	n/a	n/a	n/a
02/03/04	2-7	2-7	2-7	2-7	2-7	n/a	2-7	n/a	1-6
07/14/04	2-7	2-7	2-7	2-7	2-7	2-6	2-6	1-6	1-6
07/22/04	2-7	2-7	2-7	2-7	2-7	2-7	2-7	1-6	1-6
07/26/04	2-7	2-7	2-7	2-7	2-7	3-5	3-5	3-5	3-5
07/27/04	2-7	2-7	2-7	2-7	2-7	3-5	3-5	3-5	3-5
08/09/04	2-7	2-7	2-7	2-7	2-7	2-7	2-7	1-6	1-6
08/10/04	2-7	2-7	2-7	2-7	2-7	2-7	2-7	1-6	1-6
08/11/04	2-7	2-7	2-7	2-7	2-7	4-6	4-6	4-6	4-6
08/27/04	2-7	2-7	2-7	2-7	2-7	4-6	4-6	4-6	4-6
08/31/04	2-7	2-7	2-7	2-7	2-7	2-7	2-7	1-6	1-6
09/08/04	2-7	2-7	2-7	2-7	2-7	4-7	4-7	1-6	1-6
09/09/04	2-7	2-7	2-7	2-7	2-7	4-6	4-6	4-6	4-6
09/10/04	2-7	2-7	2-7	2-7	2-7	2-6	2-6	4-6	4-6

2.3 SAMPLE DESIGN

To capture the diversity in California's climate, and to allow customer response to time-varying rates to vary with climate, the SPP experimental design segmented customers into four climate zones. As seen in subsequent sections, demand response impact estimates are presented for each climate zone. Figure 2-2 contains a map of the four statewide climate zones and Figure 2-3 shows the distribution of utility customers across zones. About 48 percent of the population of the three utilities resides in the relatively moderate climate zone 2, 40 percent resides in the hotter zones 3 and 4 and 12 percent resides in the temperate zone 1. A map of the distribution of the SPP sample within each zone appears in Appendix 2.

Figure 2-2
Statewide Climate Zones

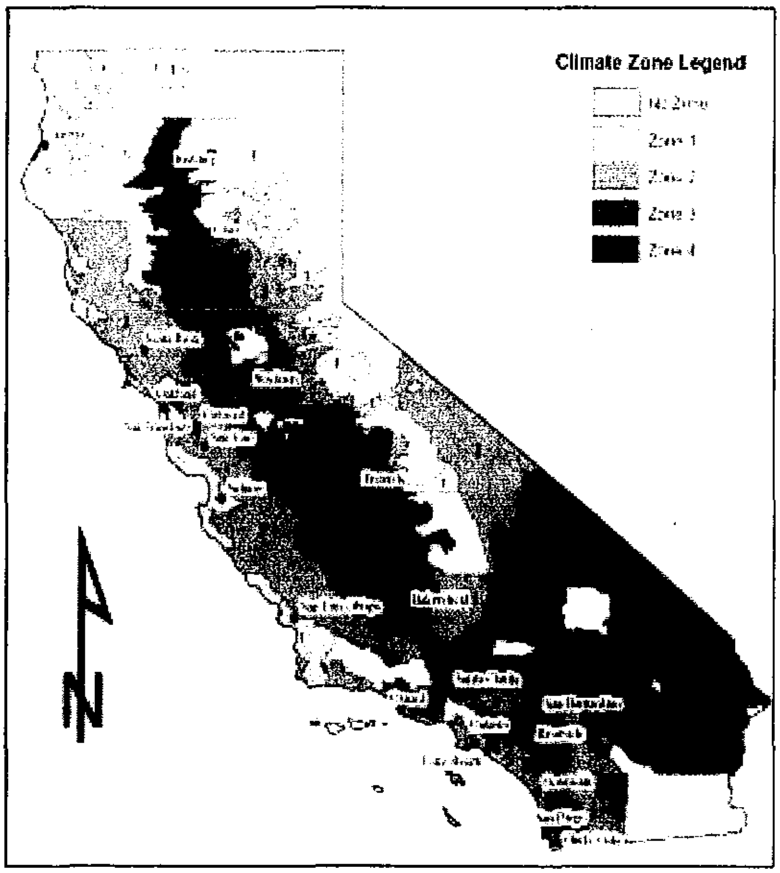
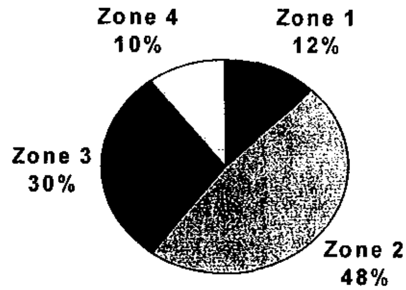


Figure 2-3
Distribution Of Population Across Climate Zones



Roughly 60 weather stations were used across the four climate zones to capture the rather significant number of microclimates that exist in California. Explanatory variables used in the regression models were based on cooling and heating degree hours.[15] The average cooling-degree hour per hour values for each climate zone are shown in Figure 2-4. They represent population-weighted averages based on the weather stations applicable to each climate zone.[16] As seen, there is significant variation in daily cooling degree hours per hour across day types and climate zones. Because cooling degree hours is not a familiar weather statistic, estimates of the average, peak-period temperature by day type and climate zone are shown in Figure 2-5.

[15] These variables are defined and further discussed in Section 3.2.3.

[16] A list of the weather stations and their populations is contained in Appendix 3.

Figure 2-4
Average Daily Cooling Degree Hours Per Hour
July Through September 2003/2004

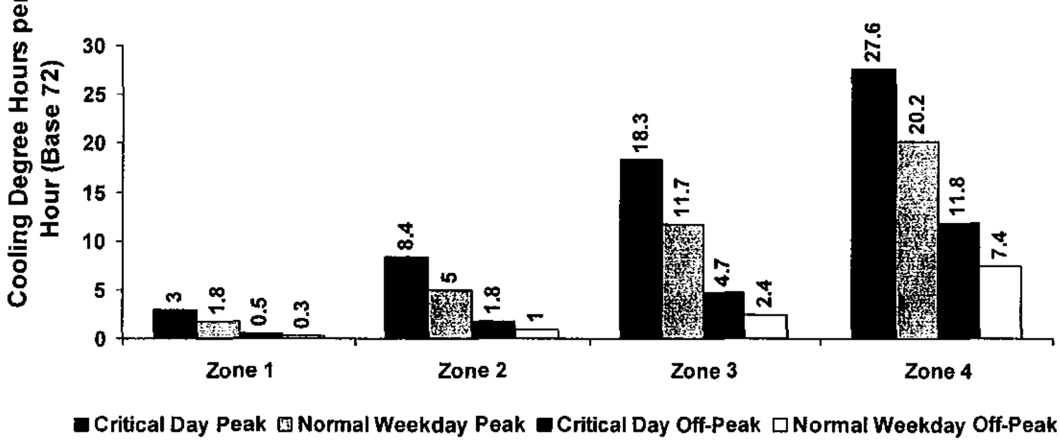
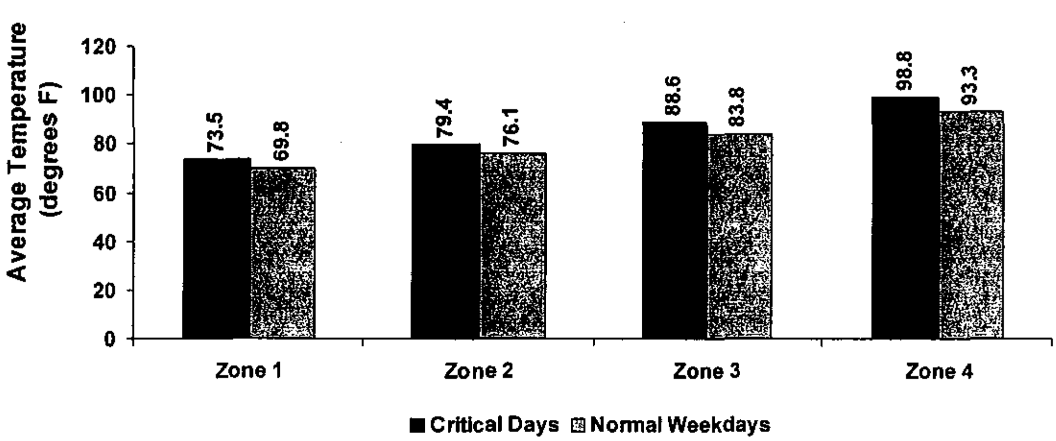


Figure 2-5
Average Temperature During Peak Period
July Through September 2003/2004



Bayesian sampling techniques were used to allocate sample points to each of the various cells in the SPP.[17] In brief, this approach allocates more sample points to cells where prior analysis indicates that the net benefits are potentially large but uncertain and fewer sample points to those cells with small or certain net benefits. The outcome of this sampling approach was that CPP-F and CPP-V cells received the largest sample allocations. Table 2-2 summarizes the original sample allocation resulting from application of the Bayesian approach in combination with judgment regarding coverage for selected cells that the Bayesian analysis otherwise would have excluded.

Within each cell, the samples were optimized to provide the greatest level of accuracy for the pre-specified Bayesian allocations. After stratifying by housing type, the Dalenius-Hodges method[18] was used to determine optimal usage cut points, and the Neyman allocation method[19], which allocates more sample points to strata with greater variance, was applied to increase the explanatory capability of the final sample. A more detailed discussion of the sample design and sample targets by utility, climate zone and treatment, is contained in Appendix 4.

The actual number and allocation of SPP control and treatment customers by time period (e.g., summer 2003, winter and summer 2004) is shown in Table 2-3 for the residential sector and Table 2-4 for the C&I sector. The number of customers participating in the pilot and the number used for estimation purposes differs, as most of the models that were estimated included information on air conditioning ownership that was obtained from a customer survey. Overall, the response rate for the survey was quite high, exceeding 90 percent for nearly all cells. In Tables 2-3 and 2-4, there are two columns representing each time period, one showing the number of customers for which load data were provided by the utility, the second showing the number of customers for which both load and air conditioning ownership data were available. The latter is closest to the number of customers that were used in most of the regression analysis.

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17 Details are presented in the December 10, 2002 report of WG3.

18 The Dalenius-Hodges procedure generates optimal stratification boundaries for a fixed number of strata within a homogenous population. Boundaries are optimal in the sense that the variance of the estimate for a given population parameter is minimized. In this instance, the technique was used to define a set of homogeneous sub-populations. Usually the stratifying variable (as is the case for this sample design) is a proxy value for the population parameter of interest. Peak-peiod demand is not known for residential customers, so summer average daily usage was used as a proxy.

19 The Neyman Optimal allocation technique assigns sampling points to each stratum based on the percentage of the total population standard deviation of the parameter of interest represented by the stratum. Neyman allocation optimizes the fixed sample size (i.e. maximizes the precision). In practice, this technique tends to disproportionately allocate sample units to the high energy users because the variance in these strata is large compared to other strata. Daily average energy use was used as a proxy for the parameter of interest (i.e., energy use during the peak period).

Table 2-2
Original Statewide Pricing Pilot Sample Design

	Control	CPP-F	CPP-F (info)	CPP-V (SDG&E) (1)	Info Only (1)	TOU	Total
Track A: Random Sampling With Opt Out Design							
Residential							
Zone 1	63	52	0	0	0	50	165
Zone 2	100	188	0	0	0	50	338
Zone 3	207	188	0	125	126	50	696
Zone 4	100	114	0	0	0	50	264
Total	470	542	0	125	126	200	**1463**
Commercial				CPP-V (SCE) (1)		TOU (SCE) (1)	
SCE							
<20 kW	88	0	0	58	0	50	196
>20 kW	88	0	0	80	0	50	218
Total	176	0	0	138	0	100	**414**
All Sectors							
Total	646	542	0	263	126	300	**1,877**
Track B: SF Cooperative							
Residential	Control	CPP-F	CPP-F (Info)	CPP-V	Info Only	TOU	Total
PG&E (2)	63	64	126	0	0	0	253
Total	63	64	126	0	0	0	**253**
Track C: AB 970 Sub-Sample							
Residential	Control	CPP-F	CPP-F (Info)	CPP-V (SDG&E)	Info Only	TOU	Total
SDG&E (3)	20	0	0	125	0	0	145
Total	20	0	0	125	0	0	145
Commercial		CPP-F	CPP-F (Info)	CPP-V (SCE)	Info Only	TOU	Total
SCE (3)							
<20 kW	42	0	0	56	0	0	98
>20 kW	42	0	0	76	0	0	118
Total	84	0	0	132	0	0	216
All Sectors							
Total	104	0	0	257	0	0	361
SUMMARY							
	Control	CPP-F	CPP-F (Info)	CPP-V	Info Only	TOU	Total
TOTAL SAMPLE SIZE	**813**	**606**	**126**	**520**	**126**	**300**	**2491**

All sample Sizes include the provision for 20% Opt-Out.

Notes:

(1) Entries are to be spread across various climate zones.

(2) This row corresponds to a proposal made by the San Francisco Cooperative and will be based on an opt out random sample located in the Hunter's Point/Potrero Hill districts of San Francisco and West Oakland/Richmond.

(3) These customers will be selected on an opt-out basis from the existing AB970 sample, which has an opt-in structure. In addition to the 20 control customers selected specifically for this study, the control group of 100 customers for the AB970 pilot is also being utilized. For any given event, half of these customers receive the dispatch signal and the other half do not. The 50 who do not are used as part of the control group for that event.

Table 2-3 Number of Residential Customers in the Experiment and Estimating Sample										
					Load Data			Load & A/C Ownership Data		
Cell ID	Customer Segment	Climate Zone	Track	Tariff	Summer 2003	Winter	Summer 2004	Summer 2003	Winter	Summer 2004
A01	R	1	A	Standard	68	62	64	51	47	48
A02	R	2	A	Standard	106	107	108	90	92	90
A03	R	3	A	Standard	105	108	108	89	88	81
A04	R	4	A	Standard	106	109	105	87	83	81
A05	R	1	A	CPP-F	59	59	61	54	54	56
A06	R	2	A	CPP-F	212	214	217	205	206	202
A07	R	3	A	CPP-F	214	215	219	200	201	203
A08	R	4	A	CPP-F	129	128	136	121	120	124
A09	R	2	A	CPP-V	n/a	n/a	58	n/a	n/a	53
A10	R	3	A	CPP-V	n/a	n/a	41	n/a	n/a	40
A11	R	2	A	Info Only (Standard)	70	64	68	65	60	64
A12	R	3	A	Info Only (Standard)	68	68	69	63	62	63
A13	R	1	A	TOU	57	57	58	55	55	56
A14	R	2	A	TOU	56	56	57	54	54	55
A15	R	3	A	TOU	58	57	63	54	53	58
A16	R	4	A	TOU	55	55	56	53	53	53
A23	R	2	A	Standard	n/a	n/a	26	n/a	n/a	21
A24	R	3	A	Standard	n/a	n/a	17	n/a	n/a	16
B01	R	1	B	Info Only (Standard)	71	53	52	48	34	33
B02	R	1	B	CPP-F	135	133	133	104	102	102
B03	R	1	B	CPP-F	78	78	78	71	71	71
C01	R	2 & 3	C	Standard	20	21	20	18	19	19
C02	R	2 & 3	C	CPP-V	131	142	135	121	127	124
C07	R	2 & 3	C	Standard	94	97	87	80	80	77

Table 2-4 Number of C&I Customers in Experiment and Estimating Sample							
Cell ID	Customer Segment	Climate Zone	Track	Tariff	Summer 2003	Winter	Summer 2004
A17	C&I <20kW	2	A	Standard	47	46	44
A18	C&I >20kW	2	A	Standard	49	46	47
A21	C&I <20kW	2	A	TOU	53	61	62
A22	C&I >20kW	2	A	TOU	53	58	58
A27	C&I <20kW	2	A	Standard	n/a	n/a	46
A28	C&I >20kW	2	A	Standard	n/a	n/a	42
A31	C&I <20kW	2	A	CPP-V	n/a	n/a	59
A32	C&I >20kW	2	A	CPP-V	n/a	n/a	83
C03	C&I <20kW	2	C	Standard	43	45	43
C04	C&I >20kW	2	C	Standard	47	44	43
C05	C&I <20kW	2	C	CPP-V	57	58	60
C06	C&I >20kW	2	C	CPP-V	89	91	89

Tables 2-5 and 2-6 summarize the evolution of the sample over time. The number of customers who left over the duration of the experiment varies by cell but is typically between 20 and 30 percent. The turnover across the four primary control group cells (A01 through A04), as measured by the total number of customers lost divided by the original starting values, is roughly 22 percent. The same measure for treatment customers (cells A05 through A08) is 21 percent. In other words, the turnover among treatment customers is almost exactly the same as the turnover among control customers, suggesting that relatively few customers dropped off the experiment because of the treatment itself.

Table 2-5 Residential Customers Added and Lost by Time Period									
Cell	Track	Treatment	Climate Zone	Start of Pilot to 10/31/03		11/1/03 to 4/30/04		5/1/04 to 9/30/04	
				Added	Lost	Added	Lost	Added	Lost
A01	A	Control for CPP-F, TOU and Info Only (zones 2 & 3)	1	68	4	0	0	2	3
A02			2	106	6	7	13	14	12
A03			3	105	5	8	11	11	11
A04			4	106	6	9	10	6	6
A05		CPP-F	1	59	4	0	4	2	0
A06			2	212	15	3	19	19	23
A07			3	215	12	3	14	18	16
A08			4	129	10	0	5	10	17
A09		CPP-V	2	0	0	0	0	58	2
A10			3	0	0	0	0	41	4
A11		Info Only	2	70	5	0	0	4	2
A12			3	68	1	1	1	2	3
A13		TOU	3	57	0	0	2	1	1
A14			2	56	5	0	7	6	2
A15			3	57	3	0	2	8	5
A16			4	55	4	0	3	4	3
A23		Control for CPP-V	2	26	0	3	7	4	2
A24			3	18	0	2	5	2	0
B01	B	CPP-F + Info Hunters Point	1	71	18	0	1	0	1
B02		CPP-F Hunters Point	1	135	7	0	3	0	10
B03		CPP-F Richmond	1	77	2	0	6	1	3
C01	C	Control	2,3	20	0	1	4	3	1
C02		CPP-V	2,3	131	5	12	3	4	14
C07		Control	2,3	94	1	4	10	0	3

Table 2-6 C&I Customers Added and Lost by Time Period									
Cell ID	Track	Treatment	Customer Segment	Start of Pilot to 10/31/03		11/1/03 to 4/30/04		5/1/04 to 9/30/04	
				Added	Lost	Added	Lost	Added	Lost
A17	A	Control for TOU	<20 kW	47	5	4	4	2	4
A18			>20 kW	49	5	1	1	3	8
A21		TOU	<20 kW	53	6	1	3	8	4
A22			>20 kW	54	1	0	2	5	2
A27		Control for CPP-V	<20 kW	47	3	1	2	4	5
A28			>20 kW	44	2	2	2	0	6
A31		CPP-V	<20 kW	0	0	0	0	56	0
A32			>20 kW	0	0	0	0	80	3
C03	C	Control for CPP-V	<20 kW	44	2	1	1	2	3
C04			>20 kW	48	5	0	1	2	4
C05		CPP-V	<20 kW	55	4	0	3	6	2
C06			>20 kW	81	5	0	5	6	6

2.4 CUSTOMER ENROLLMENT

Customers to be enrolled in the SPP were selected through a stratified sample design. A primary customer was randomly drawn from each of the strata described in Appendix 4. Nine or more alternative customers, intended to be statistical clones, were also identified. In the original SPP design, customers were to be selected and only allowed to opt-out in the case of significant hardship. However, this was unacceptable to some members of WG 3 appointed by the CPUC to oversee the experiment. A modified design was proposed where customers would be placed on one of the rates and would remain on that rate unless they decided to leave but even that proved difficult for some WG3 participants to accept. The final SPP design involved mailing an enrollment package to selected customers and obtaining an affirmative response regarding the willingness of each customer to participant. As such, it is a voluntary program but one predicated on an opt-out recruitment strategy rather than an opt-in one.

2.4.1 Recruitment

The enrollment package informed customers that they had been selected to participate in an important statewide research project that would test new electricity pricing plans.[20] The package indicated that participants would be given an appreciation payment totaling $175 ($500 for C&I customers above 20 kW demand) in three installments spanning a period of 12 months. The first installment of $25 was tied to the completion of a

20 An example of an enrollment package is contained in Appendix 5. The packages differed somewhat depending upon the treatment for which customers were recruited.

survey.[21] The second installment, equal to $75 for residential customers, was paid to all customers that stayed on the rate through the end of summer 2003 and the third installment was paid to all customers who remained on the rate through April 2004. Additional incentives will be paid to C&I Track A customers in 2005 to maintain their participation in the experiment but no additional incentives will be paid to any other participants who choose to stay on the rate in 2005.[22]

In the enrollment package, customers were asked to mail in a reply card or call to affirm their willingness to participate in the experiment. If a customer did not call the toll-free number or mail in the reply card, a recruitment consultant retained by the utilities made three attempts to call the customer to affirm their participation in the pilot. In some cases, the consultant did not have a working phone number on the customer and sent out a reminder card via mail. If a customer could not be reached after a 14-day deadline passed, they were dropped from the experiment and the recruitment process moved on to one of the statistical clones to try and fill that slot.

During the first summer of the experiment, customer recruitment activities were initiated on April 8, 2003 and continued through October 17, 2003. For Track A, TOU and CPP-F residential customers, enrollment packages were mailed on April 8th and 9th. Recruitment of Track A, CPP-V customers began on May 13th Track B packages were mailed on June 19th and Track C packages on May 3rd (C&I CPP-V) and May 13th (residential CPP-V). Recruitment of Track A, CPP-V residential and C&I customers lagged that of other treatment groups and a decision was made to terminate this effort for summer 2003 in order to reallocate recruitment resources to other cells to ensure that target levels were achieved.[23] Recruitment procedures were revised prior to the spring of 2004 and the target number of participants for Track A, CPP-V was reached for both residential and C&I customers prior to the summer of 2004.

As the experiment progressed, it became clear that the target enrollment numbers for many cells would not be reached by the July 1 start date without modifying the recruitment plan. A number of modifications were made to speed up the enrollment process, while preserving its statistical integrity. These included: (a) raising the number of phone calls, (b) reducing the 10-day deadline for customers to respond, (c) raising the number of statistical clones beyond the original nine and (d) mailing the enrollment package simultaneously to multiple clones. These changes complicated the enrollment process as multiple customers were enrolled for some slots while other slots were not filled. Customers were subsequently reallocated from slots with multiple enrollments to under-enrolled slots for which they were suitably matched.

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[21] The survey is discussed further in Section 3.

[22] The CPUC has decided to extend the experiment through the summer of 2005 for the C&I Track A, CPP-V treatment. Residential customers are being allowed to stay on their treatment tariff but without any incentive payments and they are now being charged a monthly fee for the meter and data collection. The majority of customers have stayed on the new rates rather than switch to the standard tariff.

[23] An analysis of some of the problems associated with the initial Track A, CPP-V enrollment process is contained in a separate report, *Statewide Pricing Pilot—Enrollment Refusal Follow-Up Research*, Focus Pointe, October 2003.

2. Background and Overview

As of October 31, 2003, 8,679 enrollment packages had been mailed out to recruit a target of 1,741 treatment customers (control customers were not recruited, they simply had their meters replaced). This mailing resulted in enrollment of 1,759 treatment customers for the summer of 2003. A total of 1,332 customers who were reached elected not to participate in the experiment and it proved difficult to contact or install meters on 5,134 customers. The vast majority of these were situations where repeated attempts to contact the customer elicited no response. A total of 63 customers, or four percent, elected to opt-out of the experiment between July 1 and October 31, 2003. Details by treatment have been provided in monthly reports to the California Public Utilities Commission. Customers who were enrolled in time were placed on their new rates on July 1st. Customers recruited after July 1st were placed on the rate on their next meter read date following installation of the IDR meter.

As discussed in Section 2.3, roughly 22 percent of participants and control group customers left the pilot, largely due to the normal turnover in the customer population. Most of these customers were replaced during the spring of 2004 in order to have adequate sample sizes for the summer 2004 analysis period.

2.4.2 Participant Education

Once enrolled, customers in various treatment cells were provided with a "welcome package" containing information on how to benefit from the new rate structures. They were also provided a shadow bill, as discussed earlier. Welcome packages varied by rate type and utility. Chart 11 in each package provided information about rates that the typical customer in each treatment cell would be expected to face during the pilot. A copy of one of the welcome packages appears in Appendix 6.

3. Methodology

This section provides a brief overview of the conceptual and analytical approach to the analysis that is summarized in subsequent sections. The conceptual model used is based on the modern theory of economic demand, a brief overview of which is contained in Appendix 7. Demand models are used to estimate the demand response impacts for each SPP tariff, as opposed to alternative methods such as analysis of variance and covariance, in part because they allow for estimation of the impact of prices other than those used in the pilot.

Section 3.1 below provides an overview of the model specification and some of the practical issues that were encountered and addressed as part of the empirical analysis. Section 3.2 provides a brief description of the data that were used to estimate the demand models.

3.1 MODEL SPECIFICATION AND ESTIMATION

After reviewing and testing a variety of model specifications, a decision was made to structure the analysis around the constant elasticity of substitution (CES) demand system.[24] The CES demand system consists of two equations. The first equation models the ratio of peak to off-peak quantities, expressed in logs, as a function of the ratio of peak to off-peak prices, also expressed in logs, and other terms. The second equation models daily electricity consumption, expressed in logs, as a function of the daily price of electricity, also expressed in logs, and other factors. The two equations constitute a system for predicting electricity consumption by rate period. By taking the shares of energy use by rate period that are predicted by the first equation and multiplying them by predictions of daily energy use from the second equation, one can generate predictions of the amount of energy used in each rate period given specific peak and off-peak prices and other determining factors.[25]

The CES demand system can model a variety of behavioral changes. For example, a reduction in peak period energy use with no change in off-peak energy use would be depicted as a reduction in the ratio of peak-to-off-peak energy use in the substitution equation. An increase in off-peak energy use, with no change in peak-period energy use, would also be depicted as a change in the same ratio. Conservation would be depicted by a change in daily energy use and, in the absence of any change in the ratio of peak-to-

[24] Other structural models that were examined included the log-log formulation, the quadratic and the Generalized Leontief demand system. See Appendix 7 for further discussion.

[25] A derivation of the formulas used to predict impacts by rate period based on the CES specification is provided in Appendix 8.

off-peak energy use, would still lead to a reduction in peak-period energy use because the peak-period share would be multiplied by a lower daily use value.

The data set used to estimate the demand models consists of observations on a cross section of customers that are observed over time and constitutes what is referred to in the literature as a panel data set. Given its panel nature, we have used the "fixed effects" estimation procedure to derive the model parameters. This procedure assigns a binary variable to each customer that represents the unique and unexplainable lifestyle of each customer.[26]

Equation (1) below depicts the energy share or substitution equation from the CES demand system. The equation expresses the peak to off-peak quantity ratio as a function of the peak to off-peak price ratio, a weather term representing the difference in cooling degree hours between the peak and off peak periods[27] and fixed effects variable for each customer.

$$\ln\left(\frac{Q_p}{Q_{op}}\right) = \alpha + \sigma \ln\left(\frac{P_p}{P_{op}}\right) + \delta(CDH_p - CDH_{op}) + \sum_{i=1}^{N} \theta_i D_i + \varepsilon \qquad (1)$$

where

Q_p = average energy use per hour in the peak period for the average day

Q_{op} = average energy use per hour in the off-peak period for the average day

σ = the elasticity of substitution between peak and off-peak energy use (defined below)

P_p = average price during the peak pricing period

P_{op} = average price during the off-peak pricing period

δ = measure of weather sensitivity

CDH_p = cooling degree hours per hour during the peak pricing period[28]

CDH_{op} = cooling degree hours per hour during the off-peak pricing period

θ_i = fixed effect coefficient for customer i

D_i = a binary variable equal to 1 for the i^{th} customer, 0 otherwise, where there are a total of N customers.

ε = regression error term

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[26] See the excellent discussion in James H. Stock and Mark W. Watson, *Introduction to Econometrics*, Addison Wesley, 2003.

[27] The difference in cooling degree hours per hour between peak and off-peak periods is used rather than the ratio because on some days, there are zero cooling degree hours in the off-peak period and using the ratio would result in division by zero on these days.

[28] The difference in cooling degree hours was used in the CES specification rather than the ratio of cooling degree hours in the two time periods because, in some climate zones, the value for off-peak cooling degree hours equals 0. In these cases, calculating the ratio would involve dividing by zero.

Equation (2) expresses daily energy use as a function of daily average price, daily cooling degree hours and the fixed effects variables.

$$\ln(Q_d) = \alpha + \eta_d \ln(P_d) + \delta(CDH_d) + \sum_{i=1}^{N} \theta_i D_i + \varepsilon \tag{2}$$

where

Q_d = average daily energy use per hour

η_d = the price elasticity of demand for daily energy (defined below)

P_d = average daily price (e.g., a usage weighted average of the peak and off-peak prices for the day)

CDH_d = cooling degree hours per hour during the day

ε = regression error term

The two summary measures of price responsiveness in the CES demand system are the elasticity of substitution (σ) and the daily price elasticity of demand (η). The elasticity of substitution equals the ratio of the percentage change in the ratio of peak and off-peak energy use to the percentage change in the ratio of peak and off-peak prices. The daily price elasticity equals the percentage change in daily energy use over the percentage change in daily prices. Two other common measures of price responsiveness are the own and cross-price elasticities of demand. Appendix 9 shows how the own and cross-price elasticities can be derived analytically from the elasticity of substitution and daily price elasticities for small price changes.

It is plausible that the elasticity of substitution and/or the daily price elasticity would differ across customers who have different socio-economic characteristics (e.g., different appliance ownership, different income levels, etc.). The elasticity may also vary between hot and cool days. The CES model can be modified to allow the elasticities to vary with weather and socio-economic factors, such as central air conditioning (CAC) ownership. Equation (3) provides an example of the substitution equation that allows price responsiveness to vary with CAC ownership and weather. Equation (4) shows how the elasticity of substitution would be calculated from this model specification. Equations (5) and (6) show the demand models for daily energy use and the corresponding equation for the daily price elasticity as a function of weather and CAC ownership.

$$\begin{aligned}\ln\left(\frac{Q_p}{Q_{op}}\right) &= \alpha + \sum_{i=1}^{N} \theta_i D_i + \sigma \ln\left(\frac{P_p}{P_{op}}\right) + \delta(CDH_p - CDH_{op}) + \lambda(CDH_p - CDH_{op}) \ln\left(\frac{P_p}{P_{op}}\right) \\ &\quad + \phi(CAC)\ln\left(\frac{P_p}{P_{op}}\right) + \varepsilon\end{aligned} \tag{3}$$

The elasticity of substitution (ES) in this model is a function of three terms, as shown below:

$$\text{ES}=\sigma+\lambda(CDH_p-CDH_{op})+\phi(CAC) \tag{4}$$

Other customer characteristics, such as income, household size, and number of people in the household, may also influence the elasticities in the CES model. They can be included in the specification by introducing additional price interaction terms in a similar manner to the CAC and weather terms shown above. Formulas for estimating the standard errors of the elasticity estimates when interaction terms are included, and for estimating the standard error of demand impacts based on these models, are provided in Appendix 10.

$$\begin{aligned}\ln(Q_D)=\alpha+\sum_{i=1}^{N}\theta_i D_i+\eta\ln(P_D)+\rho(CDH_D)+\chi(CDH_D)\ln(P_D)\\+\xi(CAC)\ln(P_D)+\varepsilon\end{aligned} \tag{5}$$

where

Q_D = average daily energy use per hour
η = the daily price elasticity
P_D = average daily price
ρ = measure of weather sensitivity
χ = the change in daily price elasticity due to weather sensitivity
CDH_D = average daily cooling degree hours per hour (base 72 degrees)
ξ = the change in daily price elasticity due to the presence of central air conditioning
CAC = 1 if a household owns a central air conditioner, 0 otherwise

θ_i = fixed effect for customer i

D_i = a binary variable equal to 1 for the i^{th} customer, 0 otherwise, where there are a total of N customers.

ε = regression error term.

The composite daily price elasticity in this model is a function of three terms, as shown below:

$$\text{Daily}=\eta+\chi(CDH_D)+\xi(CAC) \tag{6}$$

As described in subsequent sections, the specific price interaction terms used in the demand models vary with the rate treatment. For the CPP-F tariff, the specifications depicted above are the primary ones used, although other customer characteristics were also examined.

3. Methodology

The substitution and daily use equations could have been estimated using the generally accepted estimation method known as ordinary least squares (OLS). OLS yields unbiased parameter estimates under fairly general assumptions about the distribution of the error term. However, if the error terms do not conform to the basic assumptions of the classical regression model[29], the usual reported standard errors associated with the parameter estimates may be biased. This can happen, for example, if the error terms are either autocorrelated or heteroscedastic. The error terms are considered to be autocorrelated if the error term in a given time period is correlated with the error term in subsequent time periods. The error terms are considered to be heteroscedastic if they don't display a constant variance across cross-sectional units. [30]

In the presence of autocorrelation and heteroscedasticity, the standard errors of the parameter estimates would be biased downward which, in turn, would make the t-statistics, which are used to judge the statistical significance of the parameters, biased in an upward direction.31 Under such circumstances, one could erroneously conclude, for example, that time-varying prices have a statistically significant impact on customer energy use when there may be insufficient precision in the estimation to reach such a conclusion.

Corrections for heteroscedasticity and autocorrelation when estimation is based on panel data can be made using standard estimation software and generalized least squares (GLS) estimation methods if the panel data is balanced.[32] A balanced panel data set involves repeated observations of the same set of cross-section units. Unfortunately, the dataset used for estimating the SPP demand models was comprised of participants that were enrolled at different times. This creates an unbalanced panel, that is, one involving repeated observations on a varying set of cross-sectional units.

Given the reality of an unbalanced panel data set, as well as several other practical considerations such as the need for joint estimation of the two demand system equations, weighting and other factors, a variety of pragmatic solutions to the autocorrelation and heteroscedasticity problems were examined.[33] One such approach is averaging across the daily observations for each day type. Under this approach, for each customer, there would be an observation representing average energy use for all pre-treatment days, one

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[29] These assumptions require that the error terms to be independently and identically distributed according to the normal distribution with a zero mean and constant variance.

[30] For further discussion of these terms, see any standard textbook on econometrics such as the one by Stock and Watson mentioned earlier, Jeffrey M. Wooldridge, *Introductory Econometrics: A Modern Approach*, South-Western College Publishing, 2003; Jack Johnston and John NiNardo, *Econometric Methods*, Fourth Edition, The Mc-Graw Hill Companies, 1997; or William H. Greene, *Econometric Analysis*, Fifth Edition, Prentice Hall, 2003.

[31] The t-statistic is obtained by dividing the mean estimate of a parameter (regression coefficient) by its standard error. A value of 1.96 for this statistic indicates that the parameter estimate is statistically significantly different from zero at a 95% confidence level.

[32] For example, the TSCS PROC in SAS could be used if the panel dataset was balanced.

[33] A more detailed discussion of these empirical issues and their resolution is contained in Appendix 11.

for critical event days and one for normal weekdays during the treatment period. That is, there would be three observations for each customer, each one having a different price. A variation of this approach that introduces some additional longitudinal variation in weather would be to divide the day-type observations into days that vary in terms of weather (e.g., hot days and cool days). An approach similar to this was used to produce the results presented in the Summer 2003 report.

After estimating models based on the averaging approach described above, a close examination of the model residuals showed that not all of the residual correlations had been eliminated and there was still some downward bias in the coefficient standard errors. An alternative approach to addressing the autocorrelation problem involves transforming the daily observations using a procedure known as "first differencing." This is a common technique for dealing with serial correlation in which the previous day's observation is subtracted from the current day's observation for each of the variables in the regression equation. Compared with the averaging approach, first differencing allows for more precise estimates of both weather and price effects, since averaging suppresses the daily variation in weather and also suppresses some of the variation in prices over the course of the experiment as various (mostly minor) rate changes were rolled out by each utility. In addition, daily data makes it possible to determine the persistence of demand response over a multi-day critical event. First differencing eliminates the fixed effects and reduces the degree of serial correlation. The estimates that were derived using differenced data were similar to those using averages and fixed effects. The degree of "over-differencing" seems to be small because the implied first order serial correlation (from the Durbin Watson statistic) is typically modest.

As seen in subsequent sections, the estimated standard errors and computed standard errors for elasticities and impacts using first differences are quite small compared to the magnitudes of the estimated effects. Given the small amount of apparent over-differencing, it is implausible that there could be any pattern of serial correlation in the errors and in the regressors that would alter the statistical significance or substantially alter the confidence intervals derived from the differenced data. In other words, we don't expect that any decisions about whether or not to deploy advanced metering infrastructure (AMI) would be changed, even if some alternative approach were taken to dealing with any remaining serial correlation in the SPP sample.

One final empirical issue that was addressed concerned the joint estimation of the two equations in the CES demand system. The two equations must be estimated jointly, using a technique known as seemingly unrelated regressions (SUR), in order to obtain the most efficient parameter estimates and to account for the statistical correlations between the daily equation and the substitution equation[34]

[34] For an explanation of SUR, see Arnold Zellner, "An Efficient Method of Estimating Seemingly Unrelated Regressions and Tests for Aggregation Bias," *Journal of the American Statistical Association*, 57, 1962, 348-68.

3.2 ESTIMATION DATABASE

In order to estimate the models described in the previous section, four types of data were needed:

- Customer-specific load data
- Weather
- Customer characteristics
- Electricity prices

Each data category is briefly discussed below.

3.2.1 Customer loads

The primary load data for each customer consisted of 96 values for each day representing integrated demand at 15-minute intervals. For model estimation, the interval data were aggregated by rate period. Off-peak period energy consumption for all weekdays covered the time period from midnight until 2 pm and from 7 pm until midnight. Peak-period energy use on all weekdays covered the period from 2 pm to 7 pm for CPP-F customers. For CPP-V customers, the length of a critical event was either the entire five-hour period from 2 pm to 7 pm or a two-hour period that occurred sometime between 2 pm and 7 pm. If only two hours in length, the time corresponding to the critical period varied from day to day. When the peak period was less than five hours, a CPP-V customer would actually have three rate periods for that day: (1) the two-hour period that was priced at the critical peak rate; (2) the remaining three hours within the eligible peak period that was priced at the normal peak rate; and (3) the remaining hours in the day that were priced at the off-peak rate.

3.2.2 Customer Characteristics

Information on household characteristics was gathered through a mail survey conducted among all SPP participants, including treatment and control customers.[35] This data included information on the following variables:

- Appliance holdings
- Appliance usage patterns
- Housing type, age, size and tenure
- Socio-demographic information (e.g., persons per household, education level, language spoken and income)
- Satisfaction with utility performance
- Opinions about the environment.

[35] A copy of the residential survey instrument is contained in Appendix 12. In most instances, the survey data were recoded for use in the regression analysis. The coding instructions are contained in Appendix 13.

In the case of C&I customers, the survey was much shorter than for residential customers.[36] In brief, the C&I survey gathered the following types of information:

- Size of structure (in square feet)
- Percent of structure that is air conditioned
- Tenure (e.g., own or lease)
- Whether the bill is paid directly or as part of the rent
- Hours of operation
- Thermostat setting
- The presence of an energy management system
- Number of employees
- Type of business.

Given the importance of the survey information to the demand analysis, every effort was made to maximize the survey response rate. Multiple mailings and telephone follow-up calls were made and respondents were paid $25 for completing the survey. Toward the end of the data collection process, in some cases, site visits were made to collect information on non-respondents.

The overall survey response rate was 90 percent. In general, treatment customers responded at a higher rate than control customers. The response rates for the CPP-F, TOU and Information Only treatment groups were 96, 95 and 96 percent, respectively, whereas the average response rate for the corresponding control group was 84 percent. The response rate for the CPP-V control groups was also 84 percent while the CPP-V treatment group response rate was near 100 percent.

3.2.3 Weather

Each utility assigned a specific weather station to the control and treatment customers in its service area, based on proximity to the customer's location. This yielded a total of 58 weather stations across the state. Station-specific population values were used to calculate climate-zone-specific, weighted average values for the weather variables.[37]

Each utility provided temperature and humidity data for each weather station. PG&E and SCE provided average temperature data for each hour of each day, whereas the temperature data from SDG&E was the instantaneous reading at the top of each hour. Previous work by a PG&E meteorologist showed that there is very little difference between average hourly values and peak values within an hour, so the instantaneous readings from SDG&E were treated as if they were the same as the average values provided by PG&E and SCE. Each utility also provided data on relative humidity but this data was not used.

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[36] The C&I survey questionnaire is contained in Appendix 14.

[37] When a weather station was included in more than one climate zone, the distribution of control group customers in the experiment assigned to that weather station was used to allocate the station population to each climate zone.

Hourly temperature data were used to calculate cooling and heating degree hours by time period. The number of cooling degree hours in an hour equals the difference between a base value, say 72 degrees, and the average temperature in the hour. For example, if the average hourly temperature equals 80 degrees, the number of cooling degree hours in that hour would equal 8. The number of cooling degree hours over a period of time, say the peak period, equals the sum of the hourly values for that period. Thus, if the hourly temperature values during the 2 pm to 7 pm peak period in a day equaled 80, 82, 84, 82 and 78 degrees, the number of cooling degree hours to base 72 in that period would equal 46. A base of 72 degrees was used in the analysis after testing degree hour values to a variety of bases including 68, 70, 72, 74 and 76 degrees. There was very little difference in the results regardless of which base value was used.

Weather variables for the winter analysis were based on heating degree hours (HDH). HDH equals the difference between a base value and the average temperature in an hour. For example, if the base value is 65 degrees and the temperature in an hour equals 60, there would be 5 heating degree hours in that hour. Various heating degree hour bases were tested and the results varied little. A base of 65 degrees was used for the winter analysis.

Tables 3-1 and 3-2 contain population-weighted estimates of cooling and heating degree hours for selected time periods and seasons for the state as a whole. We have also provided estimates of average temperature for the same periods as a reference, although average temperature was not used in any of the regression models.[38] As seen in Table 3-1, there are nearly twice as many cooling degree hours in each rate period in the inner summer months than in the outer summer months. A similar pattern is seen in Table 3-2 for the difference in heating degree hours between the inner and outer winter periods. Differences in average temperature and degree hours across the two summers are small.

Table 3-1
Selected Weather Values by Season

Season	Day Type	Cooling Degree Hours per Hour			Average Temperature		
		Peak	Off-Peak	Daily	Peak	Off-Peak	Daily
2003 Inner Summer	Critical	11.5	3.2	5.0	82.9	71.1	73.6
	Normal Weekday	7.9	2.1	3.3	77.9	67.6	69.7
2004 Inner Summer	Critical	12.3	3.5	5.3	83.7	71.3	73.9
	Normal Weekday	8.4	2.1	3.4	79.4	68.6	70.8
2003/2004 Outer Summer	Critical	6.6	1.2	2.3	76.5	65.0	67.4
	Normal Weekday	5.1	1.1	1.9	74.4	64.4	66.5

[38] As described above, cooling degree hours per hour for any period are estimated by subtracting 72 from the temperature in each hour and then summing those values over the number of hours in the period and dividing by the number of hours in the period. If the temperature in a particular hour is less than 72, a value of 0 is counted for that hour. As a result, the number of cooling degree hours over a period of time will not equal average temperature in the same period minus 72, unless all hours have non-zero values.

Table 3-2 Selected Weather Values by Season							
Season	Day Type	Heating Degree Hours per Hour			Average Temperature		
		Peak	Off-Peak	Daily	Peak	Off-Peak	Daily
Inner Winter	Critical	10.0	15.9	14.6	55.0	49.1	50.4
	Normal Weekday	7.7	13.8	12.5	57.8	51.3	52.6
Outer Winter	Normal Weekday	2.8	8.2	7.1	66.6	57.9	59.7

3.2.4 Electricity Prices

Given the complexity of electricity tariffs in California, a key issue in the estimation of demand models is how best to represent the price of electricity. There is an extensive literature on this subject dating back to the mid-1970s, and it shows that many different price terms have been used, including current and lagged marginal price with and without infra-marginal price terms, price indices, current and lagged average price and total bills.[39]

Several alternatives, discussed in Appendix 15, were considered for estimating price. The method used was based conceptually on the prices that were communicated to customers in the Welcome Package they received after enrolling in the SPP. Prices using this approach vary by rate type (e.g., CPP-F), rate level (high or low) and utility. These prices appear on Chart 11 of the Welcome Package and generally correspond to the average price faced by the average customer at the outset of the pilot. For example, for the CPP-F rate in the SDG&E territory, the average price under the standard tariff was stated to be 15.5 cents/kWh. The SPP treatment rate was stated to be 10.8 cents/kWh off-peak for 85 percent of the hours in the year, 27.6 cents/kWh on-peak for 14 percent of the hours of the year and 76.8 cents/kWh super peak for 1 percent of the hours of the year. The chart also indicated the specific times for the peak and off-peak periods.

For estimation purposes, prices for all customers were set equal to the average price for a customer with consumption at the midpoint of tier 3. This approach allowed prices to vary with general rate adjustments for each utility over the treatment period. The prices also reflected whether or not a customer received the CARE discount. With this approach, prices primarily reflected the experimental design and did not vary with customer usage, making them excellent instruments for the demand models.

Reasonable results were obtained using the average price for a customer at the midpoint of tier 3. To test the sensitivity of the results to the choice of tiers, initial models were also

39 The "infra-marginal price" is the amount paid by customers on a multi-part tariff for the electricity used up to the marginal block in which they are consuming. In the simplest case of a two-part tariff with a fixed and variable component, the infra-marginal price would equal the monthly fee. However, if the tariff has two tiers in addition to a fixed monthly charge, and the consumer's usage placed him or her in the second tier, the infra-marginal price would equal the fixed charge plus the marginal price of first-tier usage times the length of the tier.

estimated using the average price for customers at the midpoints of tier 1 and tier 2. The results were quite robust across the three price sets. This is not surprising since the TOU and CPP rates implicitly impose a constant surcharge on the underlying rates during the peak and critical peak period and give a credit during the off-peak period. The amount of the surcharge and credit does not vary by tier. Since customers are spread across all five tiers, and since the average customer in all three utilities has usage that typically ends in tier 3, a decision was made to use the average price for a tier-3 customer.

Finally, demand models were estimated using both average and marginal prices. The difference in demand elasticities across these two price definitions was only 2 percent. A decision was made to use average prices because they correspond more closely to the prices in the Welcome Package. They also are conceptually the same as the prices that customers see in the supplementary billing sheet they receive each month.

4. Residential CPP-F and Information Only Treatments

This section summarizes the analysis associated with the residential CPP-F tariff. Recall from previous sections that the CPP-F tariff consisted of a two-period, TOU rate that applied on every non-holiday, weekday of the year. On normal weekdays, the peak-to-off-peak price ratio was relatively modest, but on up to 15 critical days a year, much higher peak-period prices were in effect. Customers were notified the day before a critical day that prices would be higher during the entire peak period on the following day. The weekend price equaled the weekday, off-peak price.

Table 4-1 contains average prices for the summer and winter periods for the CPP-F tariff. The average control group price was $0.13/kWh. On CPP days, the average peak-period price equaled $0.59/kWh and the off-peak price equaled $0.09/kWh, for an average price ratio of 6.6 to 1. High price-ratio customers faced a peak-period price of roughly $0.68/kWh on critical days and an off-peak price of $0.07/kWh, for a price ratio of nearly 10 to 1. Low price-ratio customers had a peak price of $0.50/kWh and an off-peak price of $0.11/kWh, for a price ratio of 4.5 to 1. The average price ratio on normal weekdays was 2.4 to 1, with a 3 to 1 ratio for the high-ratio customers and roughly a 2 to 1 ratio for low-ratio customers.

Table 4-1
Average Prices For Residential CPP-F Tariff

Season	Customer Segment	Day Type	Rate Period	High Ratio ($/kWh)	Low Ratio ($/kWh)	Average ($/kWh)
Summer (03/04)	Control	All	All	0.13		
	Treatment	Critical	Peak	0.68	0.50	0.59
			Off-peak	0.07	0.11	0.09
			Daily	0.24	0.21	0.23
		Normal Weekday	Peak	0.23	0.21	0.22
			Off-peak	0.07	0.11	0.09
			Daily	0.11	0.13	0.12
		Weekend	Daily	0.07	0.11	0.09
Winter	Control	All	All	0.13		
	Treatment	Critical	Peak	0.53	0.69	0.61
			Off-peak	0.10	0.11	0.11
			Daily	0.20	0.25	0.23
		Normal Weekday	Peak	0.32	0.11	0.21
			Off-peak	0.10	0.11	0.10
			Daily	0.15	0.11	0.13
		Weekend	Daily	0.10	0.11	0.10

A variety of important policy issues are addressed in this section. Section 4.1 presents estimates of the elasticity of substitution and daily price elasticities associated with the CPP-F rate. It also presents estimates of the impact of these rates on energy demand in each rate period. The important issue of whether impacts were similar or different during the two summers over which the SPP ran is examined. Since treatment-period data were only available for the months of July through October in 2003 and May through September in 2004,[40] a comparison across years is, arguably, only meaningful for the common months of July through September. Thus, in order to address the question of change over time, we also had to examine whether responsiveness differed across the months of July through September (designated as the "inner summer") and the months of May, June and October (designated as the "outer summer").

Section 4.2 examines the persistence of impacts across the first, second and third days of a multi-day critical event. This is an important question for estimating the benefits associated with CPP rates, as the benefits, which consist primarily of avoided capacity costs, would be much less if responsiveness declined on the second and/or third day of a multi-day event.

Section 4.3 examines how responsiveness varied with changes in customer characteristics, such as appliance holdings, income and average energy use (e.g., high versus low users). Section 4.4 presents the elasticities and demand response impacts for the winter period while Section 4.5 briefly summarizes the overall change in annual energy use resulting from the average CPP-F prices used in the experiment.

Section, 4.6, examines the Information Only treatment. Recall from Section 2 that this treatment left participants on a standard, non-time varying rate, but asked them to voluntarily curtail energy use during the peak period on critical days. This treatment was included as a cross-check on the CPP-F tariff impacts to ensure that it is the time-varying price that primarily drives behavioral response on critical days, not some altruistic desire to reduce demand when asked.

Finally, Section 4.7 provides a brief overview of the experimental design for the Track B treatment. The Track B analysis is summarized in detail in a separate report.

4.1 IMPACT ANALYSIS

This section presents estimates of the elasticity of substitution, the daily price elasticity and average impacts by rate period for the CPP-F tariff.[41] We first examine whether impacts are the same or different across the two summers, 2003 and 2004. While some relatively minor differences are found, we conclude that the most important variables (the critical day impacts and the elasticity of substitution) do not differ. Consequently, we pool the data and examine whether responsiveness differs significantly across the hotter, inner summer months of July through September and the milder shoulder months of May, June

[40] Although the experimental rate was also in effect in October 2004, data for October was not available in time to include in this analysis.

[41] The regression models underlying all of the elasticity and impact estimates discussed in this section as well as Sections 5 and 6 are contained in Appendix 16. As discussed in Section 3, the elasticity and impact estimates presented here are, in many instances, a function of the saturation of central air conditioning. The air conditioning saturations by climate zone and statewide that underlie the values presented in this report are as follows: zone 1, 7 percent; zone 2, 29 percent; zone 3, 69 percent; zone 4, 73 percent; statewide, 43 percent.

and October. Significant differences are found. Nevertheless, we also understand the need for simplicity and see the potential value of having an all-summer average rather than distinguishing between the inner and outer periods. The all-summer estimates are provided in subsection 4.1.3. The final subsection provides graphical illustrations of demand curves for energy by rate period.

As discussed previously, the impact estimates contained in the rest of this report were derived by using the two demand equations in the CES demand system described in Section 3.1. The specific formulas used to predict the change in energy use by rate period given a change in prices are relatively complex (see Appendix 8). Conceptually, the impacts are derived in the following manner. First, the elasticity of substitution and the daily price elasticity are calculated based on the population-specific values for weather and central air conditioning saturations.[42] The elasticity of substitution is used to predict the change in the ratio of peak-to-off-peak energy use given a change in the ratio of peak-to-off-peak prices. The daily price elasticity is used to predict the change in daily energy use given a change in daily average price. The two predicted values are combined to produce a change in energy use by rate period.

4.1.1 Comparison Of 2003 and 2004 Impacts

There are two approaches to examining differences in elasticities and impacts across the summers of 2003 and 2004.

One approach is to examine whether or not price response has changed for customers that participated in the experiment for both summers (designated as "common customers"). This approach addresses the question of whether demand response for the same group of customers increases (as they learn better how to respond to price signals), decreases (as the initial enthusiasm fades) or stays the same (reflecting a quick learning curve that doesn't degrade over time).

A second approach to examining the difference across years is to develop elasticities and impacts for each summer based on the entire sample of customers that participated in each summer, rather than constraining the sample to customers that are common to both years. For the CPP-F rate, approximately 57 control customers and 55 treatment customers were added to the sample after October 31, 2003 as either replacement or new participants.

Both approaches involved the use of a pooled database containing information on energy use during the treatment period for all relevant summer months from both years.[43] As discussed previously, the summer 2003 treatment period included the months of July through October whereas the summer 2004 treatment period covered the months of May through September. Given that responsiveness might vary between the milder months of May, June and October, we introduced a binary variable for the outer summer months of

[42] Not every demand model included these variables as interaction terms with price, but most did. As seen in Section 4.3, sometimes variables representing other customer characteristics were also included in the models and would be treated in this first step in a manner similar to the CAC saturation variable.

[43] The database also contained pretreatment data for all customers, whenever it occurs.

October 2003 and May and June 2004. We then compared the annual differences for the common, inner summer months of July, August and September.

A binary variable was used to represent the summer of 2004 and was interacted with all price and weather variables to assess whether or not price responsiveness varied across the two summers. If there were just a single price/year interaction term, the t-statistic for the interaction term could be used directly to assess whether or not the elasticity of substitution or daily price elasticity differed across years. However, there are three terms that underlie the elasticity estimates (e.g., price, price times weather and price times a variable representing central air conditioning ownership). Thus, standard errors had to be developed for the elasticity of substitution and for the 2004 differential that takes into account the standard errors of each price coefficient as well as the covariance across the coefficients in each equation and across the two equations in the demand system.[44] A detailed description of the calculation of standard errors is provided in Appendix 10.

Table 4-2 contains estimates for the two elasticities for 2003 and 2004 based on a database that is restricted to customers that were in the experiment in both summers.[45] These values are based on average critical-day weather across the two years. The elasticity of substitution in 2003 from the pooled model is -0.090, with a t-statistic of –20.86.[46] Table 4-2 also shows the differential value for each elasticity between the two years. The difference in the elasticity of substitution is 0.004 and, with a t-statistic of 0.64, is not statistically significant.[47]

[44] It should be noted that the standard errors of the elasticities and the impacts vary with the mean values of the weather and air conditioning saturations that underlie them. Furthermore, we note that, when estimating the standard errors, we have taken into account the fact that neither the impacts nor the elasticities are normally distributed -- they are at best approximately—by using the "delta method" for estimating standard errors, which can be applied to all the complex functions underlying the elasticities and impacts simultaneously. It is standard usage in statistics and provides a useful guide to the magnitudes of uncertainty.

[45] The 2003 values reported here differ from those reported in the Summer 2003 report primarily because these represent the inner summer months whereas the Summer 2003 values reported previously included the month of October in the estimating database.

[46] The values for the elasticity of substitution and the daily price elasticity reported in the remainder of this document are negative. When two values are compared, the value that is larger in absolute terms is referred to as "larger" because it means pride responsiveness is greater. In other words, a value of –0.2 is referred to as larger than –0.1 even though mathematically it is smaller (e.g., more negative).

[47] All statistical test results are reported at the 5 percent level of significance. A t-statistic greater than 1.96 indicates statistical significance at the 95 percent confidence level.

Table 4-2 Residential CPP-F Rate Elasticity Estimates for the Inner Summer Period (Based on Average Critical Day Weather In 2003/2004) Common Customers (Customers Present For Both Summers)			
Elasticity Type	2003 Value		
	Estimate	Standard Error	t-statistic
Substitution	-0.090	0.004	-20.86
Daily	-0.035	0.005	-7.18
	2004 Differential		
Substitution	0.004	0.007	0.64
Daily	-0.019	0.008	-2.42
	2004 Value		
Substitution	-0.086	0.005	-16.32
Daily	-0.054	0.006	-8.41

The daily price elasticity in 2003 equaled -0.035, with a t-statistic of -7.18. The annual differential value equaled -0.019 and had a t-statistic equal to -2.42, indicating that the 2003 and 2004 values differed by a statistically significant amount. The 2004 daily price elasticity was –0.054, with a t-statistic of -8.41.

Statewide impacts on peak, off-peak and daily energy use on critical days are presented in Table 4-3. Two impact measures are shown, one labeled the "average customer approach" and one labeled the "zonal weighted average approach." The average customer approach involves using input values for the impact evaluation model (e.g., weather, air conditioning saturations and starting energy use values by rate period) representing the average customer across all climate zones. The zonal weighted average approach uses input values pertinent to each climate zone and then computes a population-weighted average of the absolute impacts developed for each zone. The zonal average approach is more accurate, but computing standard errors and t-statistics for the overall average impact estimate using this approach is very complex. However, we believe the standard error based on the average customer approach is a good proxy for the standard error for the zonal weighted average approach. Therefore, we recommend that the average customer standard error be used to develop confidence bands around impact estimates based on the "bottoms-up," zonal average impact.

Table 4-3
Residential CPP-F Rate Statewide Impacts on CPP Days
Common Customers
(Based on Average Critical Day Weather in 2003/2004)

Rate Period	Starting Value (kWh/hr)	Impact (kWh/hr)	Standard Error	t-stat	Impact (%)	Standard Error (%)	Starting Value (kWh/hr)	Impact (kWh/hr)	Impact (%)
	2003 Impacts Average Customer Approach						2003 Impacts Zonal Weighted Average Approach		
Peak	1.28	-0.171	0.009	-21.47	-13.30	0.62	1.28	-0.188	-14.62
Off-Peak	0.80	0.021	0.003	7.78	2.61	0.34	0.80	0.026	3.19
Daily	0.90	-0.019	0.003	-7.25	-2.09	0.29	0.90	-0.019	-2.08
	2004 Differential Average Customer Approach						2004 Differential Zonal Weighted Average Approach		
Peak	1.28	-0.008	0.014	-0.57	-0.61	1.08	1.28	-0.007	-0.56
Off-Peak	0.80	-0.011	0.004	-2.60	-1.41	0.54	0.80	-0.009	-1.09
Daily	0.90	-0.011	0.004	-2.44	-1.17	0.48	0.90	-0.008	-0.93
	2004 Impacts Average Customer Approach						2004 Impacts Zonal Weighted Average Approach		
Peak	1.28	-0.177	0.010	-17.95	-13.81	0.77	1.28	-0.194	-15.09
Off-Peak	0.80	0.010	0.003	2.81	1.20	0.43	0.80	0.017	2.09
Daily	0.90	-0.029	0.003	-8.55	-3.24	0.38	0.90	-0.027	-2.99

The average customer impact on peak-period energy use on critical days in 2003[48] is –13.30 percent, with a standard error of 0.62 percent. The corresponding zonal average impact in 2003 is –14.62 percent. The average customer impact in 2004 is –13.81 percent, with a standard error of 0.77 percent, and the corresponding zonal average impact is –15.09 percent. The 2003 and 2004 critical day impacts are not statistically different from each other, since the differential of –0.61 percent has a large standard error of 1.08 percent and a t-statistic of -0.57.

In 2003, the average customer impact for off-peak energy use on critical days is +2.61 percent, with a standard error of 0.34 percent. The change in this impact between the two years is –1.41 percent, with a standard error of 0.54 percent. This has an implied t-statistic of –2.60, indicating that the change is statistically significant at the 95 percent confidence level. Thus, the increase in off-peak energy use on critical days was less in 2004 than it was in 2003.

[48] As discussed above, reference to a 2003 or 2004 value expresses a focus on the behavioral activity in each year and whether that differs. As such, the values are calculated based on average weather and starting values across the two years. Thus, when we say "2003 impact" we mean 2003 behavior based on cross-year averages weather values.

The impact on daily energy use on critical days in 2003 was –2.09 percent, with a standard error of 0.29 percent and a t-statistic equal to –7.25, showing that daily price was highly significant. The change in the daily energy use impact on critical days between the two years was –1.17 percent with a standard error of 0.48 percent and an implied t-statistic of –2.44. That is, daily price responsiveness increased between 2003 and 2004 by a statistically significant amount.

In summary, when the comparison is based on the same group of customers and average weather and starting values, the reduction in peak-period energy use on critical days resulting from the CPP-F rate is essentially the same during the inner summers of 2003 and 2004. The increase in off-peak energy use (resulting from the lower off-peak prices) is actually less by a statistically significant amount in 2004 than it is in 2003. The reduction in daily energy use on critical days is greater by a statistically significant amount in 2004 than in 2003.

Table 4-4 contains estimates of the elasticities based on the database that includes all customers who were in the experiment in each summer, not just the common customers. The elasticity of substitution in 2003 is –0.086, with a t-statistic of –20.51. The 2004 value is not statistically different from the 2003 value. The daily price elasticity is –0.032 in 2003, with a t-statistic of –6.80. The 2003 value is statistically different from the 2004 value of –0.054. In general, these results are very similar to those based on the common customer database.

Table 4-4
Residential CPP-F Rate
Elasticity Estimates for the Inner Summer Period
All Customers
(Based on Average Critical Day Weather In 2003/2004)

Elasticity Type	2003 Value		
	Estimate	Standard Error	t-statistic
Substitution	-0.086	0.004	-20.51
Daily	-0.032	0.005	-6.80
	2004 Differential		
Substitution	-0.001	0.007	-0.08
Daily	-0.022	0.008	-2.77
	2004 Value		
Substitution	-0.087	0.005	-16.84
Daily	-0.054	0.006	-8.55

Table 4-5 contains the impact estimates for each year based on all customers who participated in each summer using common starting values and average weather for both years. The average customer impact on peak-period energy use on critical days in 2003 is –12.71 percent, with a standard error of 0.61 percent. The corresponding all zone impact in 2003 is –14.00 percent. The impact in 2004 is –13.93 percent, with a standard error of 0.75 percent, based on the average customer approach, and the all-zone value is –15.19 percent. The two impacts do not differ from each other by a statistically significant