Have We Gotten Less Responsive To Gasoline Prices?

The gasoline price increases over the past several years have sparked outrage and alarm amongst motorists. In response, researchers at UC Davis wondered just how responsive the average car owner was to these increases. In their review of previous studies, they found that much of the research had looked at gasoline consumption data from the 1970s and early 1980s. This raised the question of whether 25 – 30 years later consumers were more or less responsive to increases in the cost of gasoline.

IN THIS ISSUE

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Since this earlier period, transportation analysts have hypothesized that a number of structural and behavioral changes have occurred in the U.S. gasoline market which have altered the responsiveness of U.S. consumers to changes in gasoline process. UC Davis researchers Jonathan Hughes (graduate student in Transportation, Technology and Policy), Christopher Knittel (associate professor of Economics), and Dan Sperling, (professor of Civil Engineering and Environmental Science and Policy and director of the Institute of Transportation Studies) decided to try and answer this question by comparing the price and income responsiveness of gasoline demand between two periods, November 1975 through November 1980 and March 2001 through March 2006. Both periods experienced relatively high gasoline prices and of similar magnitudes and increases. (See Figure 1.)

Their paper, "Evidence of a Shift in Short-Run Price Elasticity of Gasoline Demand" (CSEM WP 159), examines consumers' short-run responses to both changes in the price of gasoline and changes in their incomes. A consumer's response to higher prices is largely composed of a reduction in the amount of driving and/or an increase in the fuel efficiency of vehicles. The authors' estimates of the short-run price elasticity of gasoline demand for the period 1975 to 1980 range between -0.21 and -0.34 and are consistent with results from previous studies of this period. For the period 2001 to 2006, their estimates of price elasticity range from -0.034 to -0.077 which indicate consumers are now much less responsiveness to gasoline price changes. The estimated short-run income elasticities range from 0.21 to 0.75 and are not significantly different between the two periods.

One hypothesis for why consumers are less responsive today is that U.S. consumers are more dependent on automobiles for daily transportation

How Did Electricity Restructuring Affect Workers?

The electricity restructuring efforts in the 1990s introduced market-based incentives as a means to lower prices in the industry, in part by encouraging new participants to enter the market. These new, non-utility participants face different incentives than traditional utility owners, which is reflected in plant owners' decisions on how to best operate their plants. Numerous studies have evaluated restructuring's impact on the industry, but none had analyzed the direct impact of the new forms of ownership on input choices until now. Jennifer Kaiser Shanefelter, a doctoral candidate in the UC Berkeley Economics department and researcher at UCEI, takes a close look at what happened to the price and quantity of labor inputs at both utility and non-utility power plants during the period 1990–2004, when major shifts in ownership were taking place.

Restructuring involved the unbundling of power generation from transmission and distribution. In practical terms, there was a shift from the traditional cost-of-service regulation to a more market-oriented system in which firms get to keep whatever cost savings they achieve. Much of this shift was the result of new types of plant ownership. Some states encouraged or required the incumbent utility to divest itself of generation assets. The generation assets were then either purchased by non-utility ("merchant") firms or transferred to unregulated affiliates of the utility, which would function as a separate company. Merchants also obtained generation assets by building plants from the ground up. As a result of the encouragement of non-utility participation in the industry, merchants have played an increasingly important role over the last two decades.

Total electricity generation employment dropped from 350,000 in 1990 to 250,000 in 2003, while generation output rose from just over 3 billion megawatt-hours (MWh) to just under 4 billion MWh. In addition, during this period, average wages for generation workers increased faster than inflation. Together, these high-level facts about the industry suggest that productivity increased significantly – by about 53% in the restructured states and 46%

in the non-restructured states before controlling for plant characteristics (See Figure 1). Given this industry-wide reduction in employment during the late 1990s and early 2000s, a natural question arises: does employment differ systematically between merchant and utility plants?

In Shanefelter's paper, "Restructuring, Ownership and Efficiency: The Case of Labor in Electricity Generation," (CSEM WP-161), she analyzes whether merchant owners behave as though their incentives to cost-minimize are stronger than those of utilities. She uses plant-level annual employment and payroll data from the Bureau of Labor Statistics for the period 1990-2004 to look at the effect of ownership type at individual plants, focusing on natural-gas fired plants, because they are the predominant type of plant that was divested and that both utilities and merchants built during this time period. She first looks at plants that were divested from utility ownership as compared to both native merchant plants and utility plants that were not divested. This allows her to identify the impact of a change in ownership type. In a second analysis, she compares both divested plants and those that were constructed by merchant firms (so-called "native" merchant plants) to plants that are utility-owned.

FIGURE 1: EMPLOYEES PER MW CAPACITY
(Balanced Panel of State-Level Data)
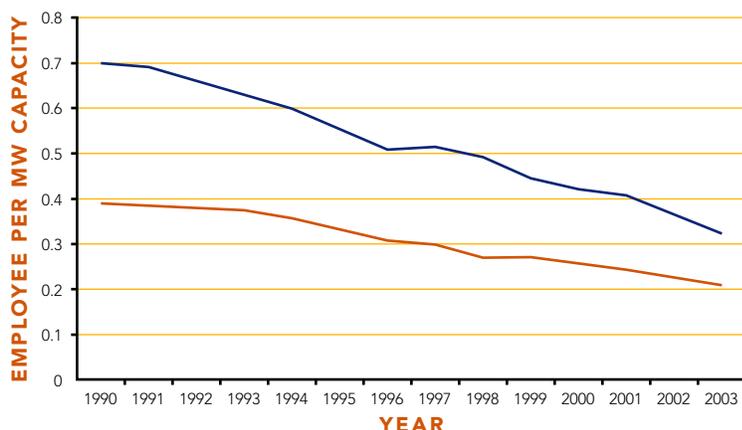
SOURCES: Quarterly Census of Employment and Wages, Bureau of Labor Statistics; Electric Power Annual 2003 – Spreadsheets, Energy Information Administration

Nonrestructured ■ Restructured ■

What Does It Take To Get Customers To Accept Critical Peak Pricing For Electricity?

When a freeze in California makes oranges scarce and sends the price of oranges sky high, people aren't very surprised. It's understandable that with fewer oranges available we would have to pay more for those remaining. Yet the notion that we should pay more for electricity at times when it is scarce creates outrage and disbelief. Consumers wonder how companies could charge more for electricity just when they need it the most. Robert Letzler, a doctoral candidate at the UC Berkeley Goldman School of Public Policy and researcher at UCEI, has tackled this problem and proposed a way to entice more customers to give up their flat priced electricity plans and save millions in generation costs.

Most consumers are on time invariant or flat electricity rates which do not change based on when the consumer uses the power or how expensive it may be for the utility to purchase the power at that time. Time-invariant rates offer consumers no incentive to shift use away from high cost periods. The combination of time-invariant prices and the need to meet electricity demand minute by minute creates a situation where utilities have to purchase power at whatever the current cost to balance the system and not cause blackouts. This is very expensive.

Several flavors of dynamic pricing – retail pricing that varies based on the cost of purchasing the electricity – have been introduced and tested in different markets. One type of such pricing is Critical Peak Pricing ("CPP"). CPP establishes three pricing periods: offpeak, peak and "critical." Prices in all three periods reflect the cost of providing the power in that period. The critical peak price is significantly higher than the peak price but occurs roughly one percent or less of the time. Critical periods are those times when power is the scarcest, such as very hot afternoons with large air conditioning loads.

Customers, however, resist signing up for CPP. California's Statewide Pricing Pilot field experiment offered participants $175 to try CPP. At the end, most participants had saved

TABLE 1: EXAMPLES OF RATES

Price Period	Time Invariant Rates	Price per kWh		
		CPP	CPP-IPR	
			Initial Price	Beyond 450 kWh/mo.
Offpeak	14.6 cents	12 cents	14.5 cents	12 cents
Peak	14.6 cents	24 cents	26.5 cents	24 cents
Critical	14.6 cents	60 cents	First 25kWh: 24 cents; 36 cent rebate for every kWh you save additional kWh after the first 25: 60 cents	

The IP rebate offer here is appropriate for a high use customer with air conditioning in a hot climate.

money, and more than 60% chose to pay a monthly fee to stay on the CPP plan. Yet, similar programs outside of California have gotten about a 1% opt-in rate. While some consumer resistance is rational, this evidence suggests that many who would be happy on CPP are not signing up for it. In Letzler's paper, "Applying Psychology to Economic Policy Design: Using Incentive Preserving Rebates to Increase Acceptance of Critical Peak Electricity Pricing" (CSEM WP 162), he presents a CPP plan that facilitates recruiting customers by addressing the non-economic factors that influence their decisions.

The psychology decision-making literature informs us of several reactions consumers have when making decisions that would bias them against opting into traditional CPP plans. Although traditional CPP improves the economic incentives, it does so in a way that makes it unappealing to consumers. It delivers subtle savings by lowering the rate most of the time, i.e., offpeak, and then drawing attention to those few critical periods with significantly higher prices by individually notifying the consumers. People tend to notice and overweight the high priced periods. Concentrating losses in a few high cost months and diffusing gains over the rest of the year can make a pricing plan unattractive to those who think about individual bills rather than the long-term cost. Studies of choice under risk suggest that consumers also often consider just the worst case scenario rather than the whole range of outcomes.

Letzler's incentive preserving rebate plan ("IPR") adds a revenue neutral set of charges and rebates to the traditional CPP. These make the high-priced critical period an opportunity to earn a rebate. IPR turns critical events into opportunities for a customer to benefit by selling each customer rights to

Does Real-Time Pricing Mean Volatile Electricity Bills?

Many economists and policymakers have argued that retail real-time electricity pricing (RTP)—retail prices that change hourly to reflect changes in the market's supply/demand balance—is an important component of an efficient and cost-effective electricity market. Still, many large industrial and commercial customers—who are likely to be the first ones exposed to retail real-time prices—express the concern that RTP would greatly increase the volatility of their bills. This is often stated as concern about the cost the customer would face for electricity consumed during an hour in which prices hit an extreme spike, such as $10,000/MWh. In Severin Borenstein's paper, "Customer Risk from Real-Time Retail Electricity Pricing: Bill Volatility and Hedgability" (CSEM WP 155 and forthcoming in _The Energy Journal_), he examines data from large California industrial and commercial customers to evaluate how much RTP might increase electric bill volatility and how that volatility might be reduced by hedging through forward power purchases.

This is the third paper in a trilogy Borenstein has written on RTP. The first, "The Long-Run Efficiency of Real-Time Electricity Pricing" (CSEM WP 133R and published in _The Energy Journal_ in 2005), examined the potential cost savings and efficiency gains from an electric system moving to RTP. The second, "Wealth Transfers from Implementing Real-Time Retail Electricity Pricing" (CSEM WP 147 and also forthcoming in _The Energy Journal_), examines the distribution of the size of the overall gains and losses among customers that switch to RTP.

In this examination of bill volatility and hedging, Borenstein studies consumption data from 1142 large electric customers for the four-year period 2000-2003 and calculates the monthly bills they would face under alternative billing arrangements. He looks at four different types of tariffs: a flat rate per kilowatt-hour; two different ``time of use'' (TOU) rates in which the customer pays different preset prices at different times of the day, week and year; and RTP, in which the price each hour is set equal to the wholesale price of electricity. The tariffs differ only in their charge for power; in all four cases, the rate has an additional fixed charge per kilowatt-hour to cover transmission and distribution. The two TOU tariffs differ in the ratio of the peak rate to the rates at other times, with one having a larger ratio that reflects the average differentials in wholesale power costs and the other having a smaller ratio that reflects the relationship that is common in actual TOU tariffs.

Borenstein constructs all four tariffs to generate the same aggregate revenue from the 1142 customers in order to avoid confusing changes in total revenues with changes in volatility. He examines three different wholesale price series as the basis of the tariffs: the actual wholesale prices in northern California (where these customers were located), a simulated price series that has relatively low wholesale price volatility, and a simulated price series that has much greater wholesale price volatility. Each wholesale price series is used to calculate a flat-rate tariff, the two TOU tariffs, and an RTP tariff that cover in aggregate the wholesale cost of the electricity these 1142 customers consumed. Using each tariff, he then constructs monthly bills for each customer based on the customer's actual consumption. To measure bill volatility he creates two indices of seasonally-adjusted bill volatility. One is a standard measure of the ratio of the volatility (standard deviation) to the average bill level (termed a "coefficient of deviation"). The second is the ratio of the highest bill the customer faces during the four-year sample to its average bill (termed a "coefficient of maximum deviation").

The initial findings support the concern that simple RTP in which the customer purchases all power at the wholesale spot price is likely to substantially increase bill volatility. Using either measure of volatility and any of the three wholesale price series, Borenstein shows that RTP generates two to five times more bill volatility than the flat rate or TOU tariffs.

But that's not the whole story, Borenstein argues. He next looks at how the volatility of bills under RTP changes if customers pre-purchase their expected power needs under long-term contract, at a price that reflects the expected price within any time period, and then buy or sell at the wholesale spot price only to cover the difference between their long-term position and their actual usage. For instance, if a customer had pre-purchased 100 kWh for every summer afternoon hour, but ended up using 117 kWh between 2-3pm on July 13, then it

TABLE 1: AVERAGE BILL VOLATILITY MEASURE UNDER THE THREE DIFFERENT WHOLESALE PRICE SCENARIOS.

AVERAGE COEFFICIENT OF DEVIATION

	High Volatility Simulated Prices	Low Volatility Simulated Prices	Actual No. Cal Prices
Flat-rate Tariff	0.155	0.155	0.155
TOU-actual ratio	0.156	0.156	0.156
TOU-cost based	0.159	0.159	0.155
RTP	0.419	0.284	0.637
RTP w/hedging	0.187	0.171	0.186

AVERAGE COEFFICIENT OF MAXIMUM DEVIATION

	High Volatility Simulated Prices	Low Volatility Simulated Prices	Actual No. Cal Prices
Flat-rate Tariff	0.318	0.318	0.318
TOU-actual ratio	0.324	0.324	0.324
TOU-cost based	0.349	0.346	0.317
RTP	1.595	0.920	1.783
RTP w/hedging	0.559	0.447	0.508

would be billed at the wholesale spot price for the additional 17 kWh. Likewise, if the customer used 88 kWh during a summer afternoon hour, it would be refunded the wholesale spot price for the 12 kWh that it had purchased under the long-term contract, but not used. Such hedging through use of long-term firm power contracts is common-place at the wholesale level and is a part of the retail RTP programs that have enjoyed the greatest success in practice. These contracts help to reduce fluctuations in the buyer's bill, but still give the buyer a strong incentive to conserve power if the wholesale price is high. Regardless of how much an RTP customer has hedged, when it chooses to use one more kWh its cost is the wholesale spot price—either directly if it is above its forward purchase position or as a lost opportunity to sell that kWh at the spot price if it is below its forward position.

Borenstein shows that even simple hedging based on a fairly uninformed guess of the customer's expected usage causes a drastic reduction in bill volatility. Under all of the scenarios examined, such simple hedging on average reduces the additional bill volatility due to RTP by at least 80% and in most cases by about 90%. Table 1 shows the average bill volatility measure under the three different wholesale price scenarios. With a straightforward hedging program, Borenstein argues, bill volatility under RTP will be only slightly different from the bill volatility that these customers currently face under TOU tariffs.

Fears that RTP could make a customer's bills less predictable are understandable, Borenstein concludes, but combining RTP with forward power purchasing eliminates nearly all of the bill volatility that RTP would otherwise introduce. At the same time, RTP would still give customers a strong incentive to reduce use when electricity is most scarce and shift usage to times when supplies are plentiful. As an antidote to expensive, scarce and polluting peak power, RTP with hedging is a valuable mechanism to align customers' and policymakers' desire for moderate and predictable power costs.

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HOW DID ELECTRICITY RESTRUCTURING AFFECT WORKERS?

Shanefelter's results show that total employment at plants under merchant ownership is approximately 30-40% lower than employment at utility-owned plants. At the same time, she finds that divested plants have the same or slightly higher payroll per employee than utility plants, while native merchant plants have significantly higher payroll per employee than utility-owned plants. These differences indicate that the labor practices at merchant and utility-owned power plants are dissimilar. Merchant plants have significantly lower total payroll costs than similar utility plants but much higher per employee payroll costs.

One explanation for the relatively higher payroll per employee at merchant plants may be that merchant plant owners have disproportionately reduced employment in lower-skill jobs. Conversations with industry and union representatives indicate that this may be due to such practices as the elimination of the apprenticeship program and the broadening of employee job descriptions. Although outsourcing of jobs is another possible explanation for the observed differences, this theory was not supported in conversations with industry participants, in press accounts, or in the limited contracting data available.

From the results presented in this paper, it is clear that the encouragement of new types of plant ownership had a large effect on labor costs in this industry. Specifically, native merchant plants have smaller staffs and lower overall payroll costs. Divested plants show a similar pattern, but when the

effect is decomposed into a merchant and a divestiture component, the merchant effect is shown to be the primary driver of the results. Plants that were conceived, built and operated as merchant plants are estimated to achieve modestly better cost savings than plants that were built by utilities and then divested to merchant ownership. This is an important point to keep in mind as new power plants are built to meet expanding electricity demand.

Shanefelter's analysis suggests that the movement toward liberalization and the use of market incentives can result in significant gains in productive efficiency. It is clear that firms are responding to the opportunity to improve their profits by economizing when there is a reward for these efforts.

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WHAT DOES IT TAKE TO GET CUSTOMERS TO ACCEPT CRITICAL PEAK PRICING FOR ELECTRICITY?

buy a block of power at the regular price during a critical event and offering a rebate for the value of any unused rights. Each customer pays a monthly fee to buy these rights. Table 1 provides an example of how IPR works relative to a flat rate and a traditional CPP plan. In this example, customers on the flat rate pay 14.6 cents per kWh regardless of when they consume the electricity. Traditional CPP customers pay less (12¢ /kWh) for their offpeak use but more for both their peak (24¢/kWh) and critical periods (60¢/kWh). IPR customers pay a slightly higher offpeak and peak rate (2.5¢/kWh higher) for the first 450 kWh per month to pre-purchase their rights, but face rates identical to the traditional CPP for any usage beyond that. The customer then has the right to access 25 kWh of power at the usual, 24¢ per kWh, price during each critical event. If the customer uses less than the 25 kWh, the customer will earn a rebate of 36¢ (i.e., 60¢ - 24¢) per kWh. For each kWh used up to 25, the customer will pay 24¢ per kWh instead of the 60¢ per kWh. In this example, the customer receives a benefit of 36¢ per kWh either in the form of a rebate or in electricity consumed up to a maximum of 25 kWh. Beyond the pre-purchased amount of 25kWh, the customer faces the true high cost of power - 60¢/kWh - during the critical event. This structure means that all customers have the strong incentive to conserve during critical periods, because they, like conventional CPP customers, give up 60¢ per critical-period kWh – often in the form of a 36¢ foregone rebate and a 24¢ charge. CPP with IPR generates the same total annual bill as conventional CPP for the same usage pattern, making the rebate program revenue neutral for both the utility and the consumer. This means that there is no way for consumers to profit by trying to strategically change the amount of rebate eligibility that they get. Revenue neutrality

means that there are no cross subsidies in the rebate program which makes it transparent, equitable, and easy to implement.

In the carrot and stick paradigm for peak-load reduction, IPR takes a "buy your own carrots" approach to rebates, reframing scarcity events as opportunities to get rebates rather than as periods of extremely high prices. IPR changes the presentation of the incentives but not the marginal incentive nor the customer's total annual payments. Changing the framing of prices is a well recognized tool in marketing. The application of psychological and behavioral information about consumers' decision making processes can be used to better "sell" many programs that public policy tells us would be advantageous, such as energy efficiency and conservation.

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# HAVE WE GOTTEN LESS RESPONSIVE TO GASOLINE PRICES?
CONTINUED FROM FRONT PAGE

than they were during the 1970s and 1980s, and as a result, are less able to reduce their amount of driving. With an increase in suburban development, people have to drive further to their destinations. In addition, with the increase in dual income households, more drivers commute daily to work which further decreases their flexibility to reduce the amount of driving. Finally, these effects are compounded since public transit is less available than in earlier decades.

From another angle, the overall improvement in U.S. fleet average fuel economy since the 1970s and early 1980s may have contributed to a decrease in responsiveness of consumers to gasoline price increases. U.S. fleet average fuel economy improved from approximately 15 miles per gallon in 1980 to approximately 20 miles per gallon in 2000. Because the vehicle fleet has become more fuel efficient, a decrease in miles traveled today has a smaller impact on gasoline consumption.

The authors investigate other possible explanations for the differences in responsiveness in the two periods. They explored whether the economic recession in the 1975 to 1980 period and its high unemployment and inflation caused people to further reduce their purchases of gasoline. Taking into account the effect of the recession did produce more inelastic price elasticity estimates for the earlier period, but not by much. The authors also investigated whether the prices in the earlier period were largely supply driven while the prices in the later period were demand driven. Although they were unable to draw definitive conclusions, their results suggested that these effects were small relative to other factors affecting price elasticity.

FIGURE 1: GASOLINE PRICES 1975-1980 & 2001-2006

November 1975 – November 1980   March 2001 – March 2006
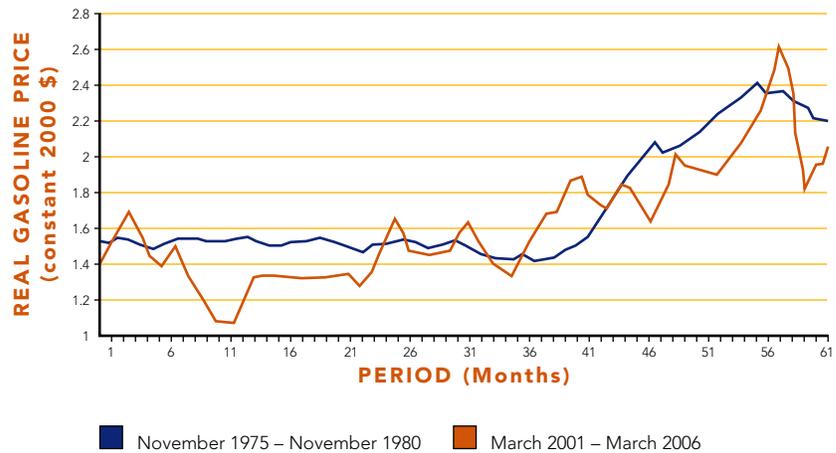
Whatever the cause, the results presented in this paper suggest that today's consumers have not significantly altered their driving behavior in response to higher gasoline prices. The estimates of the short-run price elasticity of U.S. gasoline demand is significantly more inelastic or less responsive today than in previous decades. This result is robust and consistent across several models under a range of assumption.

It is important to note that these results measure consumers' reactions to short-run changes in gasoline prices. However, it is the long-run response that is the most important in determining which policies are appropriate for reducing gasoline consumption. As it turns out, it is relatively difficult to measure long-run gasoline elasticities in practice due to factors such as the cyclical nature of gasoline prices.

Analysis of the short-run price elasticity does however provide some insight into long-run behavior. The factors that may contribute to small short-run price elasticities—such as land use, employment patterns and transit infrastructure—typically evolve on timescales greater than those considered in long-run decisions. And although consumers may respond to higher gasoline prices in the long run by purchasing more fuel efficient vehicles, if they had purchased more fuel efficient cars in the 2001 to 2006 period, one would expect to see at least a portion of this effect in the short-run elasticity. The authors are currently analyzing vehicle choice behavior across the two time periods to better understand the long-run implications of this first study.

If the long-run price elasticity is in fact more inelastic than in previous decades, this has implications for policies aimed at reducing gasoline consumption. These results imply that a gasoline tax would need to be significantly larger today in order to achieve a reduction in gasoline consumption. Higher gasoline taxes have been politically difficult to adopt which suggests that alternative measures, such as increases in the fuel efficiency standards, may be required to achieve desired reductions in gasoline consumption.

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