1984

The Impact of Time-of-Use Rates on the Peak Period Electricity Consumption of California Hydraulic Cement Firms

Michael R. Veall

Follow this and additional works at: https://ir.lib.uwo.ca/economicsresrpt

Part of the Economics Commons

Citation of this paper:
RESEARCH REPORT 8413
THE IMPACT OF TIME-OF-USE RATES ON
THE PEAK PERIOD ELECTRICITY CONSUMPTION OF
CALIFORNIA HYDRAULIC CEMENT FIRMS*

Michael R. Veall

ABSTRACT

Data on seven Californian hydraulic cement plants are used to estimate the effect of time-of-use electricity rates on peak period electricity usage. The results indicate a small dampening period of on-peak demand which is more pronounced in the winter. There is also weak support for a reduction in peak demand variance, but this is more evident in the summer.

May, 1984

* Thanks are due to Dennis Aigner, Debbie Fretz, Jerry Hausman, Joe Hirschberg, Dan McFadden, Richard Schmalensee and Sanjay Srivastava. The assistance of Ontario Hydro, the Sloan Foundation, the Energy Research Fund at M.I.T. and the Social Sciences and Humanities Research Council of Canada is acknowledged.
I. Introduction

As noted for example by Taylor (1975), there has been far less research on the potential impact of time-of-use (TOU) electricity rates on industrial users than on residential consumers. An important exception is the influential study of TOU rates in Europe by Mitchell, Manning and Acton (1978). They examine before-TOU and after-TOU demand patterns for a number of different industries and plants, and use this information to project the potential impact of TOU rates on the United States.

As one of their key examples was the cement industry (pp. 92-94), this note will study the effects of the introduction of TOU electricity pricing on seven hydraulic cement plants served by Southern California Edison. Aigner and Chung (1981) have also studied the effect of California TOU rates on the electricity usage of several industries, including hydraulic cement, but they aggregated their data (from Pacific Gas and Electric not Southern California Edison) to the industry level. Here the focus is entirely on the individual plant data.

As in Aigner and Chung, only the short-run effects of TOU rates are examined. The estimated impact on average usage is small, but of the direction expected theoretically. In addition, in Veall (1983) it is argued that user demand variance may be reduced by the TOU peak demand charges, leading to a decrease in the variance of system peak and hence to a reduction in the required reserve margin of capacity. There is some weak evidence of such an effect on user variance in the sample, primarily for the summer period.

II. Background

In pricing industrial electricity, all North American utilities use some variant of what is called a Hopkinson rate. This consists of an energy
charge (per kW-h) plus a per kW peak demand charge based on the maximum 15-minute demand by the customer during the month.\footnote{1} In October 1977, Southern California Edison substantially modified its rate structure by introducing TOU-differentiated kW-h rates and per kW peak charges confined to the maximum demands during specific time intervals. The major effect of the change, as indicated in Figures 1a and 1b, was to increase substantially the costs of using electricity during the system peak period, winter weekdays from 5:00 p.m. to 10:00 p.m. and summer weekdays from 12:00 noon to 6:00 p.m. It can be also seen in the figures that the only TOU variation in the old system was a rise in the demand charge between 6:30 a.m. to 10:30 p.m.\footnote{2}

Because all kilowatt-hour (kW-h) consumption also faces a substantial fuel adjustment charge, the true TOU kW-h rate differentials are smaller than they appear and in fact are generally less than 5 percent. The kW rate differences are much larger, a difference which was enhanced in January, 1979 when the on-peak demand charge was increased still further to $5.05 per kW and the mid-peak demand charge jumped to .65 (while kW-h charges were cut). Figure 2 shows the time path of the electricity rates, exclusive of the varying fuel adjustment charge. Other details about the before- and after-pricing schemes are presented in Veall (1981).

III. Empirical Results

The data used in this study consist of the observations at 15-minute intervals of electricity consumption by seven California hydraulic cement plants between 1976 and 1979.\footnote{3} There are therefore 21 months of observations under the old system and 27 months under the new TOU system. A longer post-TOU period would of course be desirable but this was the longest "clean" sample available. In any case, the research here is not concentrating on
long-term equipment-related adjustments but on short-term changes associated with internal rescheduling by a plant.

In this work, investigation was restricted to the system on-peak period (and those time periods during the first 21 months that would have been on-peak had the TOU schedule been in place). One reason is that, because of the complex Hopkinson rate structure noted above, the actual marginal price of usage at any time can only be approximated crudely. Hence sophisticated multiple-equation analysis seems inappropriate, especially given the focus of this work on issues related to system peak and capacity. Second, one conclusion of the work of Aigner and Chung was that own-price elasticities in the peak period were mostly significantly different from zero and correctly-signed but there was no such consistency for mid-peak or off-peak own-price elasticities or for cross-elasticities. Therefore, there likely would be little pay-off to a more general approach. Finally, as the initial sample had almost one million numbers, restricting attention to a subset of periods made the project considerably more manageable.

The next step was to convert the remaining 150,000 observations to summary monthly statistics and match these monthly observations with monthly data on electricity prices, each plant's total kW.h consumption and the average wage in the cement industry. As the intention was to run regressions using monthly means and standard deviations as dependent variables, it was of interest to know whether the underlying quarter-hourly readings were distributed normally. If they were, and if it were further assumed that the quarter-hourly readings within each month for each plant were drawn from the same distribution, then the sample mean and standard deviation would be maximum likelihood estimates of the population mean and standard deviation.
Further, as these sample estimates are themselves normally distributed and the right-hand side variables only change monthly, a least squares regression (perhaps weighted) would lead to coefficient estimates which would be maximum likelihood over the entire data set and not just over the monthly summary statistics.

However, an application of the omnibus R test of D'Agostino and Pearson (1973) using the contours of Bowman and Shenton (1975) led to a rejection of normality as the empirical distributions appear to be left-skewed. Therefore the analysis will estimate how the changes in independent variables affect the location and dispersion parameters of the underlying probability distribution of on-peak usage, but it will not identify the parameters of that unknown distribution directly.

In running regressions, a simple model was used to determine how the prices should enter the equation. Suppose there are only two periods (on-peak and off-peak) and that costs of producing output Q are

\[
C(Q_p, Q_o) = P \cdot kW.h_p + P_o \cdot kW.h_o
\]

\[+ wL_p(Q_p) + wL_o(Q_o) + mQ_p + mQ_o \tag{1}
\]

where subscripts "p" and "o" denote peak and off-peak respectively, P is the total cost of consuming a kilowatt-hour, w is the wage, L(Q) is the amount of labour required to run a shift producing level Q and m is the materials cost. Replacing \(L_p\) and \(L_o\) by arbitrary quadratic functions in \(Q_p\) and \(Q_o\) and assuming that \(kW.h\) input in each period is directly proportional to \(Q\) converts \(6\) (1) to:

\[
C*(kW.h_p, kW.h_o) = P \cdot kW.h_p + P_o \cdot kW.h_o
\]

\[+ wA_p kW.h_p^2 + wB_p kW.h_p + wC_p \]

\[+ wA_o kW.h_o^2 + wB_o kW.h_o + wC_o \tag{2}
\]
Differentiating by $kW.h_p$ yields
\begin{equation}
kW.h_p = \alpha_0 + \alpha_1 (P_p - P_0)/\alpha_2 kW.h_p, \quad \alpha_1 < 0, \quad \alpha_2 > 0
\end{equation}
where the fact that $kW.h_o$ and $kW.h_p$ sum to total kilowatt-hours, $kW.h$, has been used.

It remains to calculate $P_p$ and $P_o$ from the Hopkinson rate structure. This necessitates some kind of arbitrary assumption to deal with the $kW$ charge. The approach here is to postulate that any increase in mean peak-period usage is divided evenly over the peak period. Making a similar assumption for the off-peak period and first considering only the observations after TOU, the marginal prices for mean usage were calculated as:
\begin{equation}
\begin{align*}
P_p &= P^{kW.h}_p + FADJ + P^{kW}_p/T_p, \\
P_o &= P^{kW.h}_o + FADJ + P^{kW}_o/T_o,
\end{align*}
\end{equation}
where $P^{kW.h}$ and $P^{kW}$ are the kilowatt-hour and maximum demand charges respectively, $FADJ$ is the per $kW.h$ fuel adjustment charge and the $T$'s denote the number of hours in each period in each month.

For the period before the implementation of TOU rates, a further modification is required in that the billing peak was based on the entire month and hence would not always occur during the interval which later became the system on-peak period. Again any adjustment seems arbitrary; the one chosen defined
\begin{equation}
\begin{align*}
P_p &= P^{kW.h}_p + FADJ + (PROB_p) \cdot P^{kW}/T_p, \\
P_o &= P^{kW.h}_o + FADJ + (PROB_o) \cdot P^{kW}/T_p
\end{align*}
\end{equation}
where again the subscripts $p$ and $o$ denote the periods where consumption would have been if TOU rates had been in force. The effect of $P^{kW}$ is adjusted by multiplying by PROB, the probability that peak will occur in any period as estimated for each plant and each season using the proportion of actual peaks which occurred in each period during the first 21 months. For example, $PROB_p$ for plant 1 in the winter is .5 as five of the maximum demands in
the sample's ten winter months (prior to TOU rates) were in the time which was subsequently designated the on-peak period. 9

The basic least-squares estimate for mean on-peak kilowatt-hour usage, \(\text{MEAN}_p\), used expression (3) and employed a first-order gap-adjusted autocorrelation transform and firm and monthly dummies (whose coefficients are not reported) yielding:

\[
\hat{\text{MEAN}}_p = 1086.9 - 120124 \cdot \text{PDIF} + 0.00121 \cdot \text{kW.h} \\
(310.2) \quad (52176) \quad (0.00004)
\]

\[
\hat{\rho} = 0.66 \\
R^2 = 0.88
\] (6)

where PDIF = \((P_p - P_o) / w\); \(\hat{\rho}\) is the autocorrelation coefficient and standard errors are in parentheses. 10 The October 1977 observation for all seven firms was excluded as it was the first month of TOU rates and there were only two weeks official notice of their implementation. The PDIF coefficient has the theoretically expected sign and is significantly different from zero at the 5 percent level but implies a very small elasticity with respect to changes in \(P_p\) --only about -.05 as evaluated at the sample averages. The kW.h elasticity evaluated similarly is .88 and its difference from one is also statistically significant at the 5 percent level.

The result in (6) is robust to a number of variations, including the use of a log-linear form, employing theoretical estimates of PROB\(_p\) and PROB\(_o\) (based on an assumption that pre-TOU rate peak was distributed uniformly over time), adding \(w\) as another variable (its coefficient was not significant) and re-including October, 1977 in the sample. The own-price elasticity estimates are all between -.04 and -.10 and all are statistically significant at the 5 percent level. Of course the small initial response does not preclude a larger long-run impact associated with changes in capital stock or other factors.
To examine the effects of TOU rates on demand dispersion, define 
\text{CHANGE} as 0 before TOU rates and 1 after TOU rates. The resulting 
least-squares estimates with a first-order autocorrelation transform and 
firm and monthly dummies (whose coefficients are not reported) are:

\[
\log \left( \frac{\hat{S}_D}{\hat{p}} \right) = 6.916 + .036 \cdot \text{CHANGE} \\
(1.01) (0.051)
\]

\[ \hat{\rho} = .23 \quad \hat{R}^2 = .34 \]

where standard errors are in parentheses, and \( \hat{S}_D \) is the standard deviation 
of on-peak demand. As the high peak demand rates of the TOU rates should 
suppress demand dispersion, clearly the \text{CHANGE} coefficient does not have 
the expected sign, although it is not significantly different from zero 
at the 5 percent level. This contradictory sign continues if \text{CHANGE} is 
replaced by a peak price variable defined as the last term of \( p \) in (4) and (5), 
deflated by the wage. Surprisingly, the use of this price variable also 
worsens the fit slightly. The positive sign on \text{CHANGE} is also robust to 
adding another dummy for the second change in TOU rates, adding a log kW.h 
variable and employing a linear rather than a log-linear form.

There remains the possibility that this increase in standard deviation 
is due to rearrangements of the daily load, which is not inconsistent with 
a reduction in the variance at each point in time. To check this, as well 
as the possibility that patterns in mean usage also change, estimates based 
on sample disaggregated by season and time of day are presented in Table 1. 
The estimates come from equations comparable to (6) and (7) although only 
the \text{MEAN/PDIFF} and \text{SD/CHANGE} elasticities are reported.

All the winter mean peak usage \( \text{own-price} \) \( p \) elasticities are 
reasonably close to -.08 and significantly different from zero at the 5 
percent level. None of the summer PDIF elasticities is statistically 
significant but most have the correct sign.
With respect to the log SD/CHANGE coefficients, 11 of the 12 have the expected negative sign, with the summer coefficients having the greater magnitude. Two of the summer coefficients are also significantly different from zero using a 5 percent one-tailed test. All the results are qualitatively robust to the same modifications described with respect to estimates (7). The conclusion is that the major response to TOU rates has been in reducing mean on-peak usage, particularly in winter, but there is also weak evidence that it has reduced the standard deviation of usage, mostly in summer.

IV. Summary and Conclusions

This note examines the impact of TOU rates on the on-peak period electricity demand of seven California hydraulic cement plants. The conclusions are: (1) The quarter-hour electricity demands of such plants are not normally distributed, but have a distribution with a negative skew. (2) The response of mean demand is estimated to be small, at least in the short period covered by this study. The own-price elasticity for peak demand is estimated as -.05. This is in contrast to the California cement plant described by Mitchell, Manning and Acton (p.182) which reduced its peak demand by more than 50 percent within one year under TOU rates, implying a elasticity of magnitude of at least .5. None of the firms here responded nearly as much, which is reflected in the elasticity estimates. The estimates here are also considerably smaller in magnitude than Chung and Aigner's hydraulic cement industry estimate of -.227. While this may be partly due to the use of individual plant data and other
differences in approach, much of the discrepancy is probably
due to the different samples. Of course, while the results
here indicate a smaller short-run response to TOU rates than
previous work, it should be emphasized both that the results are
specific to these particular plants and that it is possible that
the long-run response is substantially greater.

(3) For these plants there is some difference between the responses
in the winter (evening) and summer (daytime) on-peak periods. The
mean demand price elasticity is about -.08 in the winter and
virtually zero in the summer. This suggests that analysis that
does not provide for different responses by season (in addition to
including seasonal or monthly intercept dummies) can be misleading.

(4) As argued in Veall (1983), it may be important to know whether
higher on-peak demand charges reduce on-peak demand variance and hence
reduce the optimal reserve margin. There is some weak evidence of this
effect in the sample, with the effect more pronounced in summer, when
system peak in fact occurs.
Footnotes

1 Some utilities use intervals longer than 15-minutes; the one-month billing period appears to be standard. The advantages and disadvantages of the Hopkinson rate are discussed in Veall (1983).

2 This was accomplished by a provision that if the user's peak demand occurred in the off-peak period, the user was charged for its on-peak period maximum plus one-half of the amount the off-peak maximum exceeded the on-peak maximum.

3 Thanks are due to Dennis Aigner and Joe Hirschberg for provision and interpretation of the data.

4 Six observations were removed at this stage as obvious outliers leaving 330 observations in total.

5 The omnibus R test of D'Agostino and Pearson (1973) is a joint test based on the fact that the true skewness and kurtosis coefficients under normality are zero and three respectively. Using the finite sample joint confidence contours of Bowman and Shelton (1975), normality is rejected at the 5 percent level in all but 12 of the 330 monthly observations. About 95 percent of the monthly skewness coefficients are negative.

6 This assumption seems reasonable given that most electricity in the hydraulic cement industry is used for grinding and there is no energy substitute in that process. Note also that an arbitrary quadratic "changeover" function in $Q_p - Q_o$ could be added to (1) without altering any results.

7 As can be seen from the rate description above, there was also a mid-peak period. However when it was included in the analysis, the results were less successful, probably because differences in the off-peak and
mid-peak prices were small and changes were generally in the same
direction and of about the same magnitude. Therefore the two were
combined in $P_o$, by calculating $P_{\text{mid}}$ and $P_{\text{off}}$ analogously to (4)
and then calculating their weighted average, basing the weights on the
proportions of each month that were mid-peak and off-peak respectively.

8 The $P_{\text{kw*}}$ is in the $P_o$ equation of (4) because if the peak
occurred at certain times (see Figures 1a and 1b) the effective marginal
rate for maximum demand would be $P_{\text{kw}}/2$ (see footnote 1). $P_{\text{kw*}}$ has been
adjusted for this by using the empirically-estimated probabilities (by
firm and season) to weight the two possible marginal rates appropriately.

Also before TOU rates there was a declining block structure but
as all the firms were consistently on one block, the marginal rate is used.

9 Aigner and Chung's method of defining the price variable was to
assume for each period kW and kW.h were proportional so that, for example,
the price $P_p$ was total on-peak period charges divided by kW.h. This is
more suited for the industry level because the kW/kW.h ratio changes
substantially for plants in our sample. In addition, before TOU rates, $P_p$
defined as in Aigner and Chung will fluctuate sharply depending whether
or not the monthly peak (which before TOU rates bore the entire kW change)
falls in what was subsequently the peak period. The method here using
the variable PROB solves the latter problem.

10 It should be emphasized that all the results here focus on changes
in load pattern conditional on kW.h and are therefore in a sense the
econometric equivalent of the before- and after-load curves popular in this
kind of analysis (e.g. Mitchell, Manning and Acton (1978)).
References


Gallavan, W.M., "Experience with Rates for Large Commercial and Industrial Customers in California," paper presented to the Fifth Annual Symposium on Ratemaking Problems of Regulated Utilities (February 1979), Kansas City, Missouri.


Figure 1a

Electricity Rates before and After Implementation of TOU Rates in 1977, California, Winter Weekday (November-April)

Energy Charges (per kW.h)

<table>
<thead>
<tr>
<th>$/kW.h</th>
<th>8</th>
<th>17</th>
<th>22</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>0.5</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1.0</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

TOU schedule → old schedule

Demand Charges
(per kW of individual maximum demand)

<table>
<thead>
<tr>
<th>$/kW</th>
<th>6:30</th>
<th>8</th>
<th>17</th>
<th>22</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>100</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>200</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

TOU schedule → old schedule

1: Before TOU rates, charges were based on a declining block rate structure. The rates graphed are the marginal prices for large users who have at least 10,000 kW of maximum demand and at least 300 kW.h of total monthly consumption for every kW of maximum demand. The latter part of this requirement corresponds roughly to the user having a load factor (average demand over peak demand) of at least 42 per cent.
Figure 1b

Electricity Rates before and after implementation of TOU Rates in 1977, California, Summer Weekday (May - October)

Energy Charges (per kW.h)

TOU schedule

old schedule

Demand Charges
(per kW of individual maximum demand)

TOU schedule

old schedule

1: Before TOU rates, charges were based on a declining block rate structure. The rates graphed are the marginal prices for large users who have at least 10,000 kW of maximum demand and at least 300 kW.h of total monthly consumption for every kW of maximum demand. The latter part of this requirement corresponds roughly to the user having a load factor (average demand over peak demand) of at least 42 per cent.
Figure 2
Electricity Rates\textsuperscript{1} for Large Industrial Users
California 1976-1979

Energy Charges (per kW·h)
\[ \text{\$ per kW·h} \]

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>All periods</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Peak</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mid-peak</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Off-peak</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Demand Charges
(per kW of maximum demand)
\[ \text{\$ per kW} \]

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>All periods</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Peak</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mid-peak</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

\textsuperscript{1} Before TOU rates, charges were based on a declining block rate structure. The rates graphed are the marginal prices for large users who have at least 10,000 kW of maximum demand and at least 300 kW·h of total monthly consumption for every kW of maximum demand. The latter part of this requirement corresponds roughly to the user having a load factor (average demand over peak demand) of at least 42 per cent.
Table 1

Estimated Response to TOU Rates by Time-of-Day and Season

<table>
<thead>
<tr>
<th>Season</th>
<th>Hour</th>
<th>Elasticity of Mean Usage with Respect to $p^1$</th>
<th>Coefficient of CHANGE in Standard Deviation Equation (7)$^2$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Winter</td>
<td>5:00 - 5:59 p.m.</td>
<td>-.085 (.028)</td>
<td>.151 (.183)</td>
</tr>
<tr>
<td></td>
<td>6:00 - 6:59 p.m.</td>
<td>-.081 (.025)</td>
<td>-.113 (.164)</td>
</tr>
<tr>
<td></td>
<td>7:00 - 7:59 p.m.</td>
<td>-.085 (.028)</td>
<td>-.038 (.130)</td>
</tr>
<tr>
<td></td>
<td>8:00 - 8:59 p.m.</td>
<td>-.095 (.032)</td>
<td>-.161 (.169)</td>
</tr>
<tr>
<td></td>
<td>9:00 - 9:59 p.m.</td>
<td>-.065 (.026)</td>
<td>-.015 (.178)</td>
</tr>
<tr>
<td>Summer</td>
<td>Noon - 0:59 p.m.</td>
<td>.046 (.057)</td>
<td>-.259 (.149)</td>
</tr>
<tr>
<td></td>
<td>1:00 - 1:59 p.m.</td>
<td>.036 (.050)</td>
<td>-.229 (.164)</td>
</tr>
<tr>
<td></td>
<td>2:00 - 2:59 p.m.</td>
<td>-.016 (.028)</td>
<td>-.099 (.171)</td>
</tr>
<tr>
<td></td>
<td>3:00 - 3:59 p.m.</td>
<td>-.030 (.030)</td>
<td>-.201 (.192)</td>
</tr>
<tr>
<td></td>
<td>4:00 - 4:59 p.m.</td>
<td>-.012 (.020)</td>
<td>-.071 (.193)</td>
</tr>
<tr>
<td></td>
<td>5:00 - 5:59 p.m.</td>
<td>-.002 (.018)</td>
<td>-.367 (.180)</td>
</tr>
</tbody>
</table>

$^1$ From equations like (6) which have been estimated with the dependent variable as mean usage during that specific time period. The estimation technique was least squares with a first-order autocorrelation transform and firm and monthly dummies. Elasticities estimated at the sample means. Standard errors are in parentheses.

$^2$ From equations like (10), which have been estimated with the dependent variable as the standard deviation of the demand during that specific time period. Estimates are from OLS regression as the estimated correlation coefficients first-order autocorrelation transforms were never statistically significant at the 5 percent level.