FOREWORD

The bylaws of the National Regulatory Research Institute state that among the purposes of the Institute is:

> . . . to carry out research and related activities directed to the needs of state regulatory commissioners, to assist the state commissions with developing innovative solutions to state regulatory problems, and to address regulatory issues of national concern.

This study—the second in our series of Occasional papers—helps meet that purpose. The issue of alternative rate structures for utility company tariffs is a current concern of national and state regulatory officials. This involves questions of elasticities, the effectiveness of peak load pricing and the makeup of rates among the several components of a tariff schedule.

Much has been written about energy charges in billing; relatively less about the demand component. Dr. J. Stephen Henderson's paper considers the possible usefulness of altering demand charges as a conservation measure. It is published here as a contribution to the general debate on rate structure.

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ELECTRIC SYSTEM LOAD PATTERNS AND DEMAND CHARGES

I. INTRODUCTION

Virtually all industrial customers of privately owned electric companies and most commercial customers are billed both for the electric energy they use (in kilowatt-hours) and for their maximum demand (in kilowatts) during the billing period. The price for the users' maximum demand is called the demand charge by the electric industry while the kilowatt-hour price is usually referred to as an energy charge. Just as residential price schedules for kilowatt-hours have a declining block form, industrial tariffs usually have declining blocks for both components.

As an illustration of their importance, between one-third and one-half of industrial and commercial electricity bills are demand charges, accounting for approximately 20 percent of electricity revenue. Any customer who must pay for his monthly maximum rate of demand would naturally tend to smooth out his time pattern of consumption, thereby improving his own load factor and possibly also improving the utility's systemwide load factor. These circumstances suggest that demand charges might contribute to a socially efficient pricing structure.

This paper presents empirical evidence about the electricity demand of industrial firms that pay a combination of energy and demand charges. The extent that utility system peak loads are affected by these prices is also examined. The first sample is a cross-section of the industrial customer component of investor-owned electric companies in 1970. Large electricity users had faced the energy and demand charge type of tariff for many years prior to 1970 and, accordingly, had ample time to adjust the pattern of their own electricity capacity requirements in relation to the energy content of their purchases. The sample thus avoids the drawbacks of experimental data; however, this virtue is gained at the expense of aggregation. The second sample is a 1970 cross-section of power pools and individual investor-owned utilities for which systemwide peak demand data are reported.

To my knowledge, there has been very little econometric analysis of the relatively rich U.S. experience with demand charges. Spann[1] uses demand charges to estimate peak demand using monthly time series data for one utility. The econometric studies of Mount, Chapman, and Tyrell[2], Baxter and Rees[3] and others reviewed by Taylor[4] have not included demand charges.

This paper does not address the policy question of peak-load pricing directly. While demand charges may have desirable system peak properties, such prices did not vary by time of day in 1970, and relatively few utilities had even a seasonal price variation. The extent that demand charges have

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[1] R.M. Spann and E.C. Beauvais, "Econometric Estimation of Peak Electricity Demands," Elective Power Research Institute, Special Report EA-578-SR, Palo Alto, California, December 1977.

[2] T.D. Mount, L.D. Chapman, and T.J. Tyrell, "Electricity Demand in the United States: An Econometric Approach," Oak Ridge National Laboratory (ORNL-NSF-EP-49), Oak Ridge, Tennessee, June 1973.

[3] R.E. Baxter and R. Rees, "Analysis of the Industrial Demand for Electricity," **Economic Journal,** Vol. 78, June 1968, pp. 277-298.

[4] L.D. Taylor, "The Demand for Electricity: A Survey," **The Bell Journal Economics,** Vol. 6, No. 1, Spring 1975, pp. 74-110.

a role in socially efficient peak-load pricing, however, depends on electricity users' behavior towards them and in that sense, this paper contributes to a fuller understanding of the policy issues. The policy literature mostly ignores demand charges. The FEA study of Electric Utility Industry Demand, Costs, and Rates[5] acknowledges them but does not include them in its demand study. Joskow[6] suggests that any combination of demand and energy charges yielding the same total revenue has identical implications. Despite the lack of published theoretical work, the calculation of marginal cost-based demand charges in practice, however, is possible and has been done by the National Economic Research Associates (NERA), a consulting firm, for seasonal variation and in principle could be found by time of day.

This report is divided into four sections, the first three of which give the econometric estimation of three variables: industrial energy use, industrial peak demand and the utility's system peak. A brief discussion of the policy implications is contained in the final section.

II. INDUSTRIAL ENERGY USE

The sample for the first equation consists of 159 privately owned electric utilities. Data were gathered from sources that were specific to the utility if possible. Of the variables listed in Table 1, the dependent variable, industrial kilowatt-hour use and the predictors, energy price, demand charge, average energy price and number of industrial customers were gathered from FPC documents. The number of cooling degree days came from **Climatology Data, National Survey**[7] for the utility's geographical area. Information on wages and the price of substitute fuels is not available, unfortunately, for the utility's service area. This information is published by states, however, and was associated with each utility in a state for this study. That is, all 10 utilities in Texas, for example, were assigned the same wage rate. The final variable is the total value added by the firms in the 6 most electricity intensive industries, defined as two-digit SIC's from the census of manufacturing state data. The six SIC's are those previously identified by the Conference Board[8].

The two price variables are from the National Electric Rate Book[9] that contains all of the tariff sheets used by public utilities in the U.S. The marginal prices for both the energy and demand components were found for the representative customer. Virtually all utilities have two or more tariff schedules that apply to their industrial customers, depending on the customer's use. Hence, large power users might be distinguished from smaller industrial customers. For most utilities, identifying the representative tariff sheet and, within that, the appropriate block energy and demand prices was straightforward. Having no information on the relative amount of revenue generated by the various tariff sheets, no averaging among tariff sheets was attempted. For a few utilities, this procedure resulted in marginal energy prices higher than the average revenue per kilowatt-hour actually collected—an impossibility. This occurs because a few very large customers pay a lower price on separate large power user schedules. In these instances, the large power user tariff sheet was used because it seems likely that marginal changes in aggregate industrial consumption are heavily influenced by that price schedule.

Utilities have a variety of ways of writing tariffs containing demand charges. The Hopkinson method is direct and provides a (possibly) declining block schedule for both kilowatt-hours and kilowatts. The Wright type of tariff bills a customer at a relatively high rate for each kilowatt-hour used in the first x hours use of kilowatt billing demand. A lower kilowatt-hour price prevails for additional consumption. Effectively, if a customer's own peak increases by 1 kilowatt, holding energy

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[5] **A Study of the Electric Utility Industry Demand, Costs, and Rates,** Federal Energy Administration, No. 53, July 1976.

[6] Paul L. Joskow, "Applying Economic Principles to Public Utility Rate Structures: The Case of Electricity," in C.J. Cicchetti and J.L. Jurewitz, **Studies on Electric Utility Regulations,** Ballinger Publishing Co., Cambridge, Massachusetts, 1975.

[7] **Climatology Data, National Survey,** U.S. Department of Commerce, U.S. Weather Bureau, Vol. 21, No. 1, January 1970.

[8] **Energy Consumption in Manufacturing,** The Conference Board, Ballinger Publishing Co., Cambridge, Massachusetts, 1974.

[9] **National Electric Rate Book,** Federal Power Commission, 1970 and 1969.

use constant, x kilowatt-hours are transferred from the low- to the high-price category. If the kilowatt-hour price difference (say 2¢ minus 1¢) is 1¢, for example, and x is 100 hours, a marginal kilowatt costs $1.00, and the price of additional energy (kilowatt-hours) is 1¢. There are many variations of these two basic formats, including, for example, ratchet charges where the customer's peak is the highest over the previous 6 or 12 months. All of these tariff types can be converted into an equivalent long-run marginal energy and demand charge combination. That is, any differences in behavior induced solely by the form of the tariff were ignored here, including any short-run behavior associated with rachet effects.

The estimated energy demand equation has the double-log form or

$$\log Y = \alpha_0 + \sum_{i=1}^{P} \alpha_i \log x_i$$

where Y is the kilowatt-hours demanded, the x_i are predictors and the α_i are estimated parameters that can be interpreted as elasticities. Table 1 gives the ordinary least squares estimates of each elasticity and its corresponding t statistic. The result is that the demand charge does indeed reduce energy use. The demand charge elasticity is −.5 and statistically significant at the 5 percent level. The energy charge has a larger effect, −1.95, and is also significant. The smaller demand charge effect is due to the expenditures on each component. Since demand charges are only about one-third of industry's electricity costs, it is natural to expect its elasticity to be smaller from the general principle that demand elasticities are larger for items with a larger expenditure share.

The overall response of industrial demand to increased cost of electricity production depends on how the utility divides its cost into energy and demand components. If both prices use by the same proportion, the overall elasticity is −2.45, somewhat higher than results reported elsewhere. Mount, Chapman, and Tyrell[10], for example, report industrial elasticities of about −1.8. The difference is not due to using marginal as opposed to average price used by Mount, et al. The equation using average energy price (revenue per kilowatt-hour) is reported as equation 2 in Table 1, and the price elasticity is coincidently equal to −2.45. The higher elasticities encountered here are probably due to the sample of utility companies. Even though the data are highly aggregated, they are more disaggregated than the state data used in other studies. The remaining variables in Table 1 all have the expected sign and, with the exception of cooling degree days, are statistically significant.

TABLE 1

Industrial Kilowatt-Hour Elasticities and T-Ratios*

	Equation 1		Equation 2	
	Elasticity	T-ratio	Elasticity	T-ratio
Energy price (marginal)	−1.95	9.2		
Demand charge (marginal)	− .50	3.0		
Average energy price			−2.45	10.1
Wages	1.08	2.0	1.45	2.8
Substitute fuel price	.82	3.2	1.37	5.2
Number of industrial customers	.62	18.7	.57	17.9
Cooling degree days	.11	1.1	.16	1.7
Electric intensive value added	.09	1.7	.10	2.1
Constant	−15.63		−21.21	
R^2	.77		.78	

*These were estimated using ordinary least squares with 1970 data.

[10] Mount, Chapman, and Tyrell, "Electricity Demand in the United States: An Econometric Approach."

III. INDUSTRIAL PEAK DEMAND

The second equation expresses industrial peak demand as a function of the same explanatory variables except that cooling degree days are omitted, and maximum summer temperature is substituted for those utilities having summer peaks. The sample and double-log specifications are the same as before. The desired dependent variable is the peak demand by the utility's industrial customers regardless of when that peak occurs. By measuring the separate individual peak of this user class, we can determine the extent to which its own maximum usage is influenced by demand charges and other factors. Unfortunately, there is no reported direct measure of peak demand of any user category; however, it is possible to calculate it indirectly in a way that is plausible although some error undoubtedly occurs.

To simplify matters, suppose that (a) all industrial users of a utility can be considered identical or at least can be represented adequately by the average industrial customer, (b) all industrial customers are billed on the same tariff schedule, and (c) the tariff schedule has a single energy price and a single demand charge instead of declining blocks. If all of these were true, the industrial group's peak demand could be exactly calculated from published data. That is, the equation used by the utility to calculate the industrial bill has two prices, total energy used and peak demand. Peak demand is the only unknown and may be deduced from the other variables. Since none of the above three simplifications actually holds, the procedure is at best an approximation. The most serious limitation to this idea is that utilities often have several industrial tariffs. The greatest improvement in these results would be to analyze the revenues, kilowatt-hours sales and complete price schedules separately for each tariff sheet thereby eliminating both (b) and (c). For this paper, this simplified procedure was used and resulted in 40 observations having an implied industrial load factor greater than unity. Although these observations are obviously flawed, the results in Table 2 include them since the estimates may be biased otherwise. Even though this measurement for a single observation has some error, it should be correlated with systematic differences between the industrial groups of separate utilities.

The results of applying ordinary least squares to this approximation of industrial peak load are reported in Table 2, and the elasticities are similar although higher than those in the energy demand equation. The elasticity of peak demand to energy price is -2.39 and statistically significant. Again, the energy price elasticity is higher than the demand elasticity, $-.47$, despite the fact that demand charges are designed as a direct price on maximum use because energy charges are a relatively large part of costs. The elasticities from both tables suggest, since peak demand is reduced more than energy use by the energy charge, that the industrial load factor improves somewhat with the energy charge. The difference between the two energy price elasticities is not statistically significant; however, if true, this result is somewhat counterintuitive, although not completely implausible. Spann[11], for example, suggests that increased energy prices raise off-peak energy price relative to peak energy costs since the demand charge applies only at the customer's peak time; and hence, load factors should deteriorate with energy prices. Spann implicitly assumes that energy prices at peak and off-peak times sufficiently describe all price effects. In a world with declining block structures, however, the average price of electricity has separate effects on the decision to install electricity using capacity. Since energy charges are a larger fraction of a customer's bill than demand charges, the elasticity of average price is correspondingly higher for the energy price. In these circumstances, the energy price effect acting through the average price may be a sufficiently large incentive to reduce investment in electricity using equipment that the customer's load factor actually improves. More evidence is needed before accepting this argument; however, these results suggest that energy charges may be a useful way of improving the efficient use of electricity capacity.

The demand charge does not apparently affect industrial users' load factors at all since energy and peak demand have similar elasticities. The expected positive response is apparently not observed because of the relatively weak effect that demand charges have on average prices.

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[11] Spann and Beauvais, "Econometric Estimation of Peak Electricity Demands."

Since the elasticity estimates are all plausible and all but one are statistically significant and also since 70 percent of variation in the calculated peak load can be explained, the evidence seems to confirm that the indirect procedure for measuring maximum demand does indeed capture systematic differences among utilities. Despite this, it is somewhat troubling to use the energy and demand prices as predictors since these are two of the variables used to construct the dependent variable. Ordinary least squares estimates are likely to exhibit simultaneity bias in these circumstances. To eliminate this problem, the same equation was estimated using two-stage least squares. This estimation procedure essentially creates new energy and demand charge variables by first fashioning an auxiliary equation to predict these two prices from other information. These predicted prices are then used to explain peak demand. The resulting estimates were similar to those in Table 2, although both price elasticities were larger. As in Table 2, peak demand was more responsive to energy price than to the demand charge and, to the extent that asymptotic t-tests are reliable, the statistical significance of all the variables was similar to Table 2 values.

TABLE 2

Industrial Peak Demand (Kw) Elasticities

	Elasticity	T-ratio
Energy price (marginal)	−2.39	9.5
Demand price (marginal)	− .47	2.4
Wages	1.65	2.7
Substitute fuel price	1.98	6.7
Number of customers	.57	14.5
Summer max. temperature*	.004	2.3
Electric intensive value added	.06	1.0
Constant	−32.43	
R^2	.70	

*This variable is 0 if the utility has a winter peak and logarithms were not used; hence, its coefficient is not an elasticity.

IV. SYSTEM PEAK DEMAND

The third and final equation predicts the utility's systemwide peak load during 1970. The dependent variable for this equation is reported in **Electric Power Statistics**[12] that gives monthly system peak loads for most privately owned companies as well as for many public electric enterprises. These statistics are gathered for individual utilities as well as for groups of utilities, the most important of which are several power pools such as the New York Power Pool. For each such group, the explanatory variables in the previous sample were either aggregated or averaged, as appropriate, and the group was considered a single observation. Any observation with aggregated final sales less than 70 percent of the reported generation in **Electric Power Statistics** was omitted, thereby avoiding power pools with a large number of non-investor owned utilities and entities that do not correspond to companies. In all, the sample consists of 19 groups (power pools and groups whose members are subsidiaries of one another) and 70 independent utilities, for a total of 89 observations. To my knowledge these data have not been previously used to estimate utility peak demand elasticities.[13] Given the lack of published estimates, I report the results in two ways: first in structural and then in reduced form.

A correctly specified structural equation to explain a utility's peak demand includes the peak demands and energy use of all customer groups plus any factors that affect the coincidence of these separate peaks such as weather and geographic variables. The separate customer peak

[12] **Electric Power Statistics**, 1970, Federal Power Commission, 1970.

[13] This refers only to the economics literature. I suspect a government researcher or consultant has worked with these data but has not published the results.

demands are then explained in other equations. A structural equation for the utility's peak, for example, would not include prices since such economic variables are expected to influence customers directly through their own demand equations that would then indirectly alter the utility's peak through the customer peak demand variable. Factors such as the percent of air-conditioned houses might be included in such a structural equation even though air conditioning is also a direct determinant of residential peak demand. The reason is that air conditioning undoubtedly interacts with weather conditions so that the coincidence of peak demands within the residential group and among other groups increases significantly on a hot day. This type of weather interaction may change the coincidence within the utility's distribution system in a way that is not adequately represented by the presence of an air-conditioning measure in the residential equation alone.

The reason for including both peak and energy use variables is that separate customer peaks are not coincidental and the off-peak demand of the residential class, for example, may occur at the time of the system peak. Since separate customer class peaks cannot be directly observed, I have used the previously defined measure of the industrial peak demand and a similarly constructed variable for commercial customers. A difficulty in estimating commercial peak demand is that only two-thirds of the utilities actually used demand charges for their typical commercial customers. After constructing the commercial peak demand variable for utilities with positive demand charges, an auxiliary equation was estimated that predicted commercial peak demand from a series of exogenous variables including such measures as the number of customers in all three categories; weather conditions; state economic variables such as income and wages; a set of variables describing the nature of the state regulatory structure such as Public Utility Commission expenditures; and whether or not the commission is elected or appointed. This equation was used to estimate commercial peak demand in the third of the sample having no commercial demand charge. The resulting measure is clearly quite inadequate and from Table 3 provides no significant explanation of the utility's system peak. It is included to be symmetric with the treatment of industrial customers and is not important in this paper.

The first equation in Table 3 shows that the bulk of the marginal responsibility for the system's peak rests on residential customers. The elasticity of the system peak with respect to residential use is 62 percent. Any increase in commercial demand augments the system peak by only 12 percent as much, while the industrial elasticity is about .24. The sum of the first five elasticities in equation 1 is .97. The fact that this number is less than 1 indicates that a scaling up of all demand simultaneously results in somewhat less than a proportional increase in the system peak. That is, there are economies of scale in providing a common electricity capacity that serves many customers with non-coincident peaks. It is a measure of how diversity among customers affects peak demand at the margin.

The estimated economies of scale ($1 - .97 = .03$) are small for two reasons. First, the current size of many power pools undoubtedly has exploited most of the available economies. Second, equation 1 was estimated with ordinary least squares and is plagued with serious multicolinearity among the five measures of separate customer demands. Under these conditions, the length of the estimated coefficient vector is systematically overestimated which implies that the estimated economies are underestimated for this type of joint demand function.

To overcome this difficulty partially, the equation was estimated using a technique known as ridge regression, a good discussion of which is in Hoerl and Kennard[14]. This procedure introduces a small amount of bias into the estimates in an attempt to reduce the mean square error of prediction. The researcher selects a value of k, between 0 and 1, to add to the main diagonal of the correlation matrix of predictors. The choice of k is arbitrary and although a theoretical optimal value of k exists, it depends on the unknown population parameters and cannot be found in practice. Various suggestions for choosing k have appeared in the literature, the most common being to observe how the set of coefficients respond to k and to select the lowest value that stabilizes the coefficients. On that basis, a value of $k = .1$ was used, and the results are equation 2 in Table 3.

[14] A.E. Hoerl and R.W. Kennard, "Ridge Regression: Biased Estimation for Nonorthogonal Problems," **Technometrics**, Vol. 12, February 1970, pp. 56-67.

TABLE 3

Utility System Peak Load Elasticities

	Equation 1 (OLS)		Equation 2 (Ridge regression)		Equation 3 (OLS)		Equation 4 (Ridge regression)	
	Elasticity	T-ratio	Elasticity	T-ratio	Elasticity	T-ratio	Elasticity	T-ratio
Residential sales	.624	13.0	.359	24.3				
Commercial sales	.116	3.2	.249	16.8				
Commercial peak demand	.0006	1.7	.001	2.3				
Industrial sales	.239	9.1	.226	14.8				
Industrial peak demand	−.009	.5	.086	6.2				
Maximum temperature*	.0013	3.1	.0008	2.1	.0009	2.8	.0011	2.5
Percent air conditioning	.023	.9	.057	2.4	.038	2.0	.085	3.3
System kilowatt-hours					.96	105.4	.84	60.7
Residential energy price					.038	.7	.090	1.1
Commercial energy price					−.077	1.6	−.153	2.3
Dummy variable for commercial demand charge**					−.15	1.7	−.038	.9
Commercial demand charge					.042	1.4	.035	2.6
Industrial energy price					−.047	1.1	−.142	2.2
Industrial demand charge					−.009	.3	−.097	2.0
Intercept	−.342		.84		−1.75		−1.48	
R^2	.9923		.9875		.9956		.9855	

*This variable is 0 if the utility has a winter peak and logarithms were not used; hence, its coefficient is not an elasticity.

**This variable is 1 if the utility has no commercial demand charge; otherwise it is 0.

The ridge regression estimates suggest that residential customers have a substantially smaller peak responsibility with an elasticity of only .359, as compared to .624 from the OLS equation. Both commercial and industrial responsibilities are larger. Commercial responsibility is .25 according to the ridge estimates, as compared to the OLS estimate of .116. The industrial elasticity (total) grows from .23 to .312, so that both the OLS and ridge techniques suggest the same order of responsibility: residential, industrial and commercial. The t-statistics for the ridge regression are included in Table 3 to show that in some sense the coefficients have been estimated more precisely than was allowed by OLS; hence, the multicolinearity problem has been somewhat alleviated. In a descriptive sense, these statistics seem useful; however, these t-ratios should not be interpreted in the conventional way since the sampling distribution of the individual ridge regression coefficients is unknown.

The sum of the first five ridge coefficients is .92, indicating that economies of scale are about .08, substantially larger than the .03 OLS estimate. A proportional increase in all demands requires a growth in peak capacity that is 8 percent smaller. Both of these scale economy estimates were statistically significant at the 1 percent level. Caution is once again needed to avoid misinterpreting linear hypothesis tests in ridge regression; however, since the 3 percent estimate was obtained from OLS, it seems clear from both estimates that such economies are indeed real.

The elasticities of industrial demand in Tables 1 and 2 can be combined with the system peak elasticities to calculate the implied elasticity of system peak with respect to both types of industrial prices. Using equation 1 in Table 3 (OLS estimates), the elasticity of the system peak to changes in the industrial energy price is .44, while the demand charge has a smaller effect, .11. It is not possible to construct a convenient statistical test for these indirect estimates; however, a reduced form equation provides an alternative way of measuring these price effects and also yields the usual t-statistics. This reduced form is equation 3 in Table 3. Six price variables are included in the equation: two for industrial users, one for residents and three for commercial customers where one of these is a dummy variable to indicate whether or not the utility used commercial demand charges. The system kilowatt-hour variable is used to control for scale and is the generation reported in **Electric Power Statistics**[15]. The need to include a scaling variable means the equation is not strictly reduced form but rather, prices may affect the peak through this variable. This undoubtedly accounts for the low-price elasticities in equation 3; however, it was not possible to estimate the equation sensibly without such a variable due to the large variation in system peaks from the New York Power Pool to small, independent New England companies.

Equation 3 shows that both industrial prices tend to reduce the system peak, although neither is statistically significant. The set of price variables is so highly colinear that estimation precision is poor. As before, ridge regression was used to overcome this problem with the outcome shown as equation 4. The ridge method suggests that the industrial energy price has a peak elasticity of −.142, while the demand charge elasticity is −.097. Both of these have t-ratios that would be significant in OLS equations; however, the ridge method prevents this interpretation. The demand charge elasticity, −.097, is close to the indirectly calculated number, −.11. The industrial energy charge, however, has a substantially smaller effect in the reduced form, −.142, than the industrial equations suggest, −.44. The reason is that the scaling variable is measured in kilowatt-hours and is absorbing a larger portion of the variation due to energy prices than is due to demand charges. Despite the presence of this scaling measure, equation 4 suggests that both types of industrial prices are effective in reducing system peak demand.

Both the commercial demand charge and residential price have unexpected signs, although both are small and statistically insignificant. Whereas industrial users are likely to have their peaks at times close to the system peak, this is less likely for residents and small commercial customers with the result that the system peak is less sensitive to their prices.

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[15] **Electric Power Statistics.**

V. SOME POLICY IMPLICATIONS

Even though a single year's data are insufficient to estimate precisely the demand charge influence on peak requirements, it seems clear that this type of price does indeed exert some pressure to conserve both energy and capacity. Both the industrial energy demand and industrial peak-load equations suggest that the demand charge reduces electricity use although not as much as the energy or kilowatt-hour price. The reason for smaller demand charge elasticities is probably the difficulty that industrial users have in modifying their own load factors. That is, technology and work place habits are probably quite similar throughout the U.S. for the same industry. Faced with a high demand charge, a firm's manager would like to level his time pattern of demand, but the existing technology and overtime pay rates may limit his ability to reduce his electricity bill. In these circumstances, total electric energy use may be quite price elastic, but the peak load associated with that kilowatt-hour consumption is relatively inflexible. Thus, the demand charge effect is smaller than its energy counterpart in both industrial equations. This and the fact that energy costs are larger than total demand charges explain the mild paradox that industrial peak demand is more sensitive to the energy than the demand price, even though the latter is specifically designed as a charge for peak use.

Although the demand charge elasticities are low, they are still quite important. The economic implication is that industrial users value their ability to impose peak demand, just as they value the energy content of the electricity. The policy implications of this observation depend on the nature of peak-load pricing as it is implemented in the future.

Ideally, peak-load pricing would involve instantaneous feedback between the electricity user and producer. The consumer, for example, might be provided with a device that quoted the electricity price at that moment, with the price being dependent on the total system load. With this type of peak-load pricing, an idea associated with Vickery, there would be no need for a demand charge, and indeed such a charge is logically inseparable from the energy content charge of a moment's consumption. Hence, with a Vickery scheme, demand charges are superfluous.

A practical peak-load pricing policy, however, involves relatively few time intervals during which previously published prices are in effect. During the interval defined as peak, a customer's load is unlikely to be perfectly level. Given that the customer values his own peak demand within the period over which peak prices occur, a demand charge is appropriate. That is, a socially efficient pricing policy would include energy prices and demand charges, both of which vary by time of day, season and so on.

The magnitude of a socially efficient demand charge would depend on the electricity production technology and the coincidence of the separate customer peak demands within the peak price period. The original peak-load-pricing literature relied on simple technologies to illustrate the nature of the efficient pricing scheme—a strategy that seems useful here. Assume there are constant returns to scale and no substitutability among labor, fuel and capital is producing electricity. Assume also that all customers face demand and energy charges that are different during two daily time periods. Finally, it is convenient to assume that the utility's coincidence factor is constant. In this simple and unrealistic world, the socially efficient pricing policy is easily described. The off-peak energy charge would be the off-peak running costs, primarily fuel, and the off-peak demand charge would be 0. The peak energy charge would be the running costs of generating units used during the peak period, possibly different from the off-peak energy price due to the difference in running costs between base-load and peak-load generators. No capacity or capital cost would be included in the peak period energy price. Instead, all capacity costs would be recovered with peak demand charges that would equal the cost of peak-load generators multiplied by the coincidence factor, a fraction.

As the number of hours in the peak price period are reduced, the coincidence factor must approach unity since shorter time periods necessarily tend to reduce the diversity of separate customer peaks. At the limit, as the Vickery scheme is approached, the customer pays a different energy and demand charge at every moment, at any one of which the two prices have no separate identity and may as well be combined into the single price Vickery envisioned.

This discussion is meant simply to illustrate the nature of a peak-level-pricing policy that includes demand charges. The particular policy outlined above is critically dependent on the assumption that the utility's coincidence factor is constant. In fact, from the data it appears that coincidence is not at all constant, and that a realistic socially efficient demand charge would be much lower than one calculated using the above scheme. This follows from the relatively small response of the utility's system peak to demand charges. While the results presented here suggest that demand charges may be useful in designing socially efficient electricity pricing policies, additional work is needed to determine the extent of their role.

VI. SUMMARY

The empirical findings presented here illustrate that demand charges have an important influence in promoting industrial electricity conservation. The industrial consumption of electrical energy and also its requirements for peak demand are both reduced by the demand charge, although to a lesser extent than their response to the energy charge. Industrial demand appears somewhat more elastic than previously reported, due to the disaggregated data used here. These are long-run estimates, and current short-run elasticities may be quite different due to the recent rapid energy price inflation.

Since the demand charge is a direct price for a user's peak demand, it is natural to expect that it would also affect the utility's systemwide peak load, although to a smaller extent. The empirical results were mixed, in the attempt to discern any such relation. The demand charge was negative, as expected, in the equations predicting the utility's peak, but it was statistically insignificant, due to multicolinearity difficulties. The ridge regression estimates were more precise but should not be interpreted as conveying statistical confidence.

Since industrial electricity users are sensitive to demand charges, a socially efficient pricing policy may include such prices by time of day as well as by the usual time-varying energy prices. The data indicate that industrial demand responds more to energy than to demand charges. Consequently, the conservation of peak capacity requirements that could be attributed to the demand charge may be less than the corresponding capacity reductions from time-of-day pricing.

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