Customer Response to Real-Time Pricing in Great Britain

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Retail Market Management (RMM) is a concept that focuses on developing products that are differentiated by price and quality of electricity services provided to meet the needs of industry and potential market segments. Real-time pricing (RTP) is one of the many service options contained in the RMM framework. In a RTP program electricity prices change frequently to reflect the constantly changing costs of supplying electricity. Customer response to frequently changing prices offers both utilities and their customers significant benefits that include more efficient energy usage as usage is reduced at times when it is most costly and increased when it is least costly to produce.

To date, analysis of RTP has been limited to small numbers of customers on experimental programs. This paper evaluates the load response of 340 industrial and commercial customers to a permanent RTP program offered by Midlands Electricity in Great Britain. The Midlands Electricity program was introduced in 1991 in response to the privatization and restructuring of the electricity industry in Great Britain. The 340 customers on RTP provide a database that is much larger and covers a broader spectrum of customers than is currently available in the United States. The analysis of the Midlands Electricity program will assist other utilities to assess the potential impacts of instituting RTP programs.

Introduction

Retail Market Management (RMM) is a strategic and tactical approach that enables an electric utility to increase value delivered to customers and meet its own corporate goals. To do this, RMM identifies the diverse needs of existing and potential market segments, develops services and price structures tailored for these segments, and offers these services at efficient prices for customer selection. The benefits to utilities of RMM programs are increased customer satisfaction, improved utilization of existing resources, retention of present customers, development of new customers, development of new services, improved delivery of services, and an improved planning process.

There are several driving forces that make RMM an imperative. First, technological advances in generation and control systems have created the opportunity to match electric supply more efficiently with demand on a temporal and spatial basis. Second, changes in the business environment are creating the need and the opportunity for improving the value of service to customers. Third, customers are demanding differentiated products that will enable them to use electricity efficiently and economically. Fourth, serving the needs of different market segments alters the cost and revenue streams to the utility in ways that must be accounted for in product design.

Critical to utility development of product lines for target markets is knowing about customer preferences and response to different service programs, and incorporating that knowledge into a unified planning framework. Therefore, a key issue that RMM seeks to address is understanding customer response, including its load and revenue impacts, and using that understanding in product design and marketing. There are a limited number of sources of information about customer response, including customer participation in and response to interruptible/curtailable programs, outage cost surveys, and customer participation in and response to real-time pricing (RTP) programs. Each of these three data sources can provide insights into what flexibility customers have to shift load on fairly short notice in response to prices or quantity constraints. Load data from customers on RTP programs can be used to directly estimate customer flexibility to shift load both within and between days in response to price variation.

A number of utilities in the U.S. are considering or have implemented RTP programs for commercial and industrial (C&I) customers, either on an experimental or permanent basis. As of March 1993, at least thirteen U.S. utilities had customers on some form of RTP, while at least three utilities had a RTP program pending or a RTP program in place but had no customers on the service. Since that time, a number of additional utilities have begun implementing RTP programs.

The analyses conducted to date to quantify the impact of RTP have involved a relatively small number of customers on experimental programs. The results suggest that customers do have the ability to shift load in response to RTP. However, not all customers respond, and those that do respond, do not respond all the time. Analysis of the Niagara-Mohawk controlled RTP experiment suggested an average reduction in customer usage in the range of 0.1 to 0.2 percent due to a one percent increase in price. Individual customer response varied more than did the average response. Focussing on the times of peak prices, estimates of the percentage reduction in load range from 5 to 10 percent at PG&E and NMPC for the 8 or 25 days of highest prices, respectively, to a 36 percent reduction at NMPC at the highest priced hour.

In contrast to the limited number of customers and the experimental nature of the RTP programs in the U. S., a large number of electricity customers in the United Kingdom have been on a permanent RTP program since early 1991. Among these customers are approximately 340 large C&I customers who took service from Midlands Electricity in England during the 1991/2 fiscal year who form the basis for our evaluation. The large number of customers and the permanent nature of the service suggest that analysis of the Midlands Electricity data will provide valuable insights into the behavior of a broad spectrum of C&I customers. This report analyzes the response of Midlands Electricity customers during their first year on RTP. The knowledge gained from this analysis will greatly assist U.S. utilities who are contemplating RTP programs or other innovative services to predict the load and revenue impacts that would result from offering these services to their own C&I customers. This research is a collaborative effort between the Electric Power Research Institute's Retail Market Management Research Program, the Niagara Mohawk Power Corporation, and Midlands Electricity in England.

The next section of the report briefly describes Midlands Electricity's RTP program in the context of the restructuring of the British electricity industry. The following section describes the research design and the data used. The fourth section presents results. Conclusions are presented in the final section.

Midlands Electricity's RTP Program

As part of the privatization and restructuring of the electricity industry in Britain, competition has been introduced into the generation and supply of electricity, effective March 31, 1990. In England and Wales, the former Central Electricity Generating Board was broken up into three generators (the privately owned and largely unregulated National Power and PowerGen and the state-owned Nuclear Electric) and the privately owned but regulated National Grid Company which is responsible for bulk transmission. The generators bid to sell to the electricity "Pool", which is run by the National Grid Company. Plants are dispatched based on their bid. Although the generators are unregulated, they are subject to British anti-monopoly law and may be referred by the Director General of Electricity Supply to the Monopolies and Mergers Commission which has the power to require restructuring of firms or other remedies.

Transmission, distribution, and retailing (supply) of electricity are privately owned but regulated. Twelve Regional Electricity Companies (RECs), which include Midlands Electricity, distribute electricity over local networks and retail electricity. Both distribution and supply are regulated under a RPI-X formula, which relates price increases to a retail price index adjusted for a number of factors. The RPI-X regulation allows for the pass-through of certain costs, including the RECs' costs of purchasing electricity. In their supply business, the RECs purchase electricity from the national electricity pool and transport it to the final customers. Since much of the electricity is sold to final customers at a fixed price, while the suppliers purchase it at the floating pool purchase price, suppliers may purchase hedging contracts. These financial instruments are called "contracts for differences" (cfds), since only the difference between the fixed price specified in the cfd contract and the pool price changes hands between the parties to the contracts. In the first years of restructuring, only the generators sold the hedging contracts, which contained a substantial risk premium that was passed on to the final customers. Currently the market in cfds is becoming more liquid and the risk premium is being reduced.

Beginning in April 1990, customers with demands over 1 MW have been able to purchase electricity from their local REC, other RECs, or other companies, including the generators, who obtain electricity supply licenses. Beginning in April 1994, the limit falls from 1 MW to 100 kW, and beginning in April 1998, all customers can purchase electricity on the competitive market.

The pricing mechanism that has developed under which generators may sell to the pool and under which the RECs and other direct customers may buy from the pool is a half-hourly RTP structure which bears many similarities to RTP programs in the U.S. The pool prices are forecast and customers are notified of the prices a day in advance. The System Marginal Price is based on the bid by the marginal (unconstrained) plant dispatched, and thus is based on marginal costs. Prices to customers on pool price contracts also include a capacity factor (or outage costs) that are based on a loss of load probability and the value of lost load, as well as several transmission and distribution charges. Finally, the cfds hedge price risk for the RECs and for final customers and, initially at least, provided for revenue recovery for the generators. The combination of the pool price and the cfds produces a joint product that is very similar to what are known in the U.S. as two-part RTP programs that are in place at Niagara-Mohawk and Georgia Power.

To meet the competition and to reduce its risk, Midlands Electricity began offering RTP service, or as it is called in England, a pool price contract, effective April 1991. The price paid by the customers differs by half hour and includes the price paid by Midlands Electricity to the "pool" in each half hour, which is based on the generators' marginal cost, as well as charges for transmission, distribution, and taxes. The 48 prices for each day are faxed to customers the preceding day, normally soon after 4 p.m.

In the April 1991-March 1992 fiscal year, 340 customers took service on Midlands Electricity's pool price contracts, 370 in 1992/3, and 400 in 1993/4. In both 1991/2 and 1992/3, the cost of electricity for customers on pool price contracts was generally much lower than the cost for customers on non-pool contracts, in part because both winters were milder than usual, and in part because of the risk premium included in the price of the contracts for differences which is included in the price of non-pool contracts. However, in the first half of 1993/4, pool prices have been 17 percent higher than pool prices in previous years.

Research Design and Data

Price and Customer Data

The daily mean effective energy charge (where the mean is taken over the 48 half-hours in a day) is plotted in Figure 1 for the 366 days from April 1991 to March 1992.[1] The highest prices occur in September and October, and during the winter months of December, January, and February, reflecting the triad demand charge and the higher winter load. While the high winter prices were expected, the prices during September and October were higher and more variable than had been expected. An inquiry was initiated by the Director General of Electricity Supply that focussed on such things as close future monitoring and modifications in the computer programs that schedule plants and set prices. After the inquiry the prices returned to more expected levels.

Prices also vary substantially within a day. This is illustrated in Figure 2 which graphs the daily price pattern for October 1991, for the highest, three highest, three lowest, and average price days. The October trimodal price pattern contains a day-time peak, an early evening peak when people get home from work, and a later evening peak that corresponds to hours of darkness. The September and October price patterns are similar for the day types indicated in Figure 2, though it should be noted that the highest priced days in September occur at the end of the month and the highest priced days in October occur in the beginning of the month.

In the 1991/2 fiscal year, 340 customers took service on the pool price contracts from Midlands Electricity. The

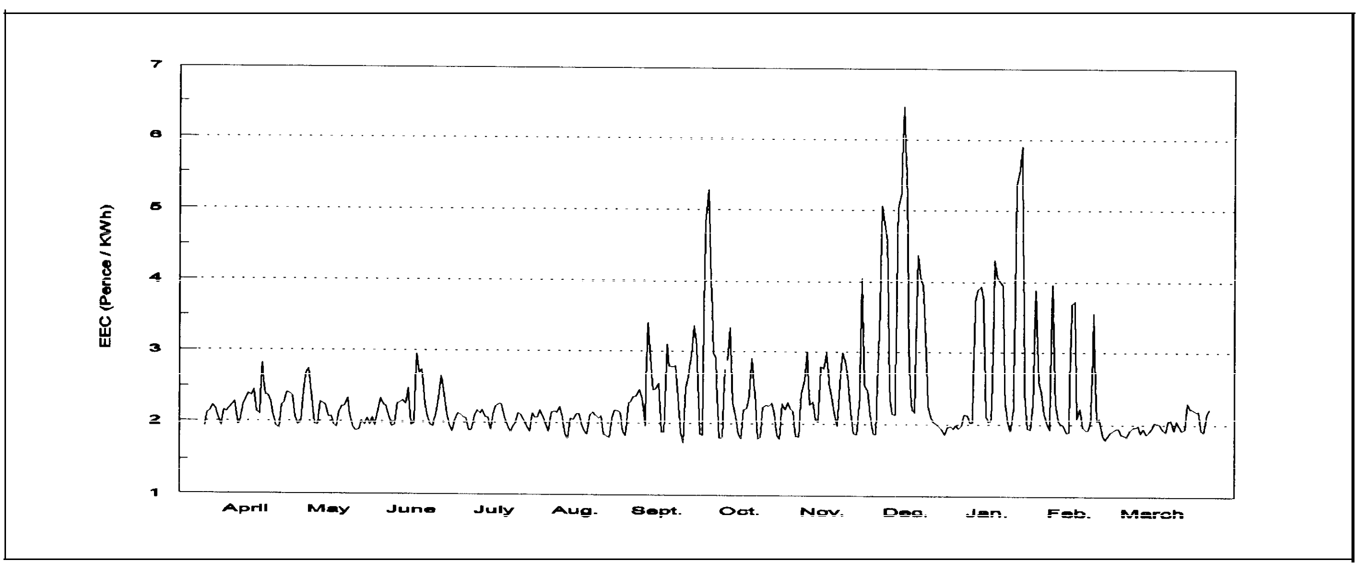

Figure 1. Effective Energy Charge—Daily Average Price

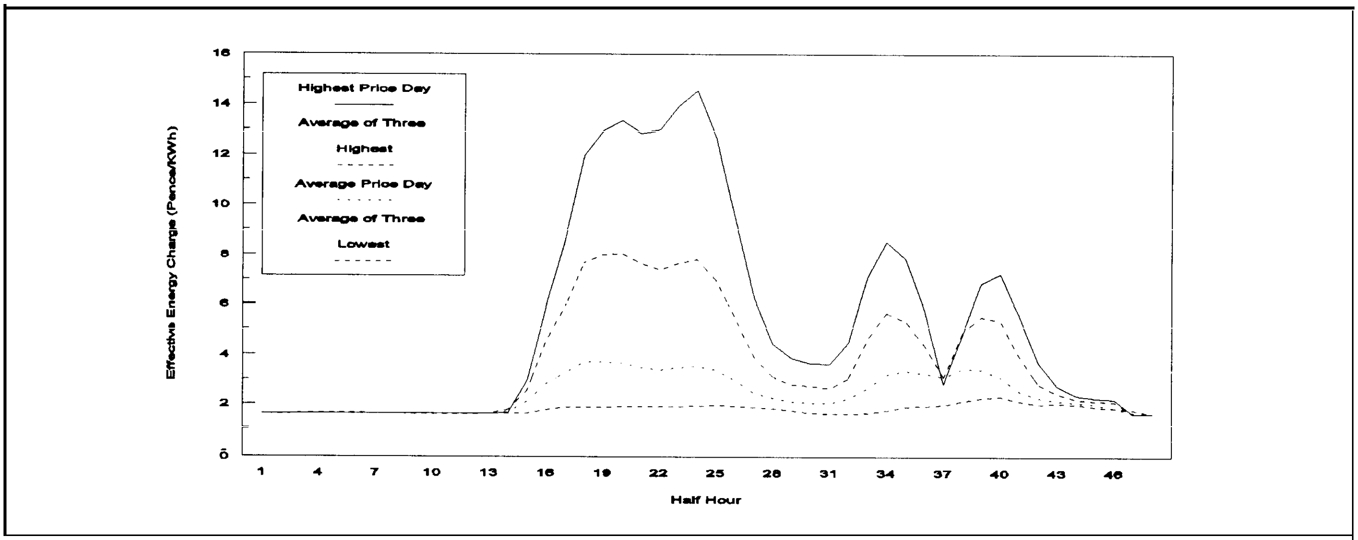

Figure 2. Average Weekday Prices by Half-Hour—October 1991

customers cover a wide spectrum of industries including 34 U.S. and 27 British SIC codes. For analysis purposes the customers are segmented into seventeen categories based on SIC codes. Table 1 displays the seventeen customer categories. The largest number of customers are in the manufacturing industries, with a smaller number in lighter industries, reflecting Midlands Electricity's customer base. There are also 19 customers in the commercial and services sector.

The Model

A model that has previously been used to evaluate customer load response to RTP characterizes customer behavior using "customer flexibility parameters," or elasticities, that describe the amount by which customers shift their electricity usage in response to a change in price. After these parameters have been estimated, the load, revenue, and customer welfare impacts of customer response to a forecasted pattern of real-time prices, possibly in another service territory, can be simulated using a demand simulation model. The results of the simulation can be used by utilities to predict the market potential and the load and revenue impacts of introducing RTP or other innovative service options.

A nested Constant Elasticity of Substitution cost function is used for estimation. This functional form characterizes customer response by the flexibility that customers have to shift load between hours within a day in response to variation in prices within that day, and their flexibility to shift load between days in response to variation in the overall price level for each day. The estimation equation used in the analysis is given in equation 1:

$$\ln(E_{dh}/\bar{E}^g_{th}) = \sum_t A_t - \sigma_h \ln(P_{dh}/\bar{P}^g_{th}) + (\sigma_h - \sigma_d)\ln(D_d/\bar{D}^g) \tag{1}$$

where E_{dh} is the electricity usage in half-hour h on day d, and P_{dh} is the price of electricity in half-hour h on day d. The variables with the bar and superscript g denote typical usage or price for that half hour of the week, and the A_t's are day-type constants.[2] The parameters estimated are σ_h, the within day flexibility and σ_d, the between day flexibility. $\ln(D_d/D^g)$, is the daily price term formed using a Törnqvist price index.[3] This formula makes it clear that usage in each half hour, relative to its typical level, is a function of the relative price in that half hour and the daily aggregate relative price. A complete derivation of the estimation equation is given in Christensen Associates and the Niagara-Mohawk Power Corporation (1991) and in Herriges, Baladi, Caves, and Neenan (1993).

Equation (1) is estimated for each SIC category for each month of the analysis. It is also estimated for individual customers. Customers for whom either the within day or the between day flexibility parameters are significant are classified as responders. The equation is then estimated for all of the responders in each SIC category. The estimation corrects for first order autocorrelation, including the first observation and taking into account missing observations by using the generalized Prais-Winsten method.

Results

The analysis reported here focuses on the months of September and October. These two months were selected since they contain the most price variation during the daytime hours in the 1991/92 period. Price variation does occur in the winter months, but it is caused mainly by the

Table 1. Industrial Classification of 1991/2 RTP Customers

SIC Codes U.S.	SIC Codes British	Number of Customers	SIC Code Description
33	22, exc. 224	27	Ferrous Metal Manufacturing
33	224	20	Non-Ferrous Metal Manufacturing
14	23	9	Extraction of Stone, Clay, Sand and Gravel
32	24	28	Manufacture of Non-Metallic Mineral Products
28,29	14,25,26	11	Chemical Industry
33	3111	27	Ferrous Metal Foundries
33	3112	15	Non-Ferrous Metal Foundries
34	312	34	Forging, Pressing and Stamping
34	313,316	21	Other Manufacture of Metal Goods
35	32,33	13	Mechanical Engineering and Manufacture of Office Machinery and Data Processing Equipment
36	34	15	Electrical and Electronic Engineering
37,38	35,36,37	19	Manufacture of Motor Vehicles and Parts, Aerospace Equipment, and Instrument Engineering
20	41,42	15	Food, Drink and Tobacco Manufacturing Industries
26,27	47	12	Manufacture of Paper, Paper Products; Printing, Publishing
30	48	35	Processing of Rubber and Plastics
22,24,39	43,46,49	13	Other Manufacturing (Textiles, Wood, Jewelry, Misc.)
			Commercial Category
50,51,53	61	3	Wholesale and Retail Distribution
79	63	3	Entertainment
42,45	64	2	Transportation
91-97	651	4	Local Government Offices
60,61	6521	4	Offices - Banks
80	68	1	Hospitals
82	69	5	Educational Establishments
80,82	89	1	Other Commercial or Services
TOTALS		337	

triad demand charge being allocated in the early evening hours, a time when more businesses than usual have reduced operations for the day due to the industrial recession in Britain.

Responders

Table 2 examines the percentage of customers that shift load in response to price. In September and October, 48 and 34 percent of the total customer population respectively responded to price.[4] The amount of response varies widely between SIC groups. In September, the most responsive SIC group contained 75 percent responders while the least responsive SIC group contained only 8 percent responders. In October, the most responsive group contained 62 percent responders and the least responsive group contained 16 percent responders. Customers that were responders in one month did not necessarily respond in another month.

Table 2. Summary of Results

	Percent of Customers that Responded: All Customers	SIC Category: Most Responsive	SIC Category: Least Responsive
September	48	75	8
October	34	62	16

Though there is substantial variation in the number of responders within each SIC group, there are some groups that consistently contain more or less than the average percentage of responders. Four SIC groups that consistently contained a higher than average level of responders are: (1) extraction of stone, clay, sand, and gravel, (2) chemical industry, (3) processing of rubber and plastic and, (4) manufacture of motor vehicles and parts, aerospace equipment, instrument engineering. Four SIC groups that consistently contained a lower than average level of responders are: (1) other manufacturing, (2) non-ferrous manufacturing (3) other manufacture of metal goods, and (4) commercial and service.

Flexibility Parameter Estimates

To quantify the amount of load shifting, customer flexibility to shift load in response to price is estimated econometrically. The model used summarizes customer load response by the flexibility that customers have to shift load within day and their flexibility to shift load between days. The flexibility parameters, which can be thought of as elasticities, describe the amount by which customers shift their electricity usage between hours within a day or between days in response to a change in prices. The numbers have the interpretation of the percentage increase in usage due to a one percent reduction in price holding other prices constant. Thus, a flexibility parameter of 0.10 indicates that the change in usage is one-tenth the magnitude of the change in price.

To illustrate within and between day customer load shifting in response to prices, Figure 3 plots the total half-hourly usage for the paper manufacturing and publishing category for the three highest priced days and for the three lowest priced days in October. The load shape is quite different for the two sets of days, with usage on the high priced days being lower than on the low priced days during mid-day when prices on the high price days were the highest (as was shown in Figure 2). However, the general load level over the course of the day is similar for the two sets of days, indicating that customers are shifting load within the day but not between days.

While graphs of the usage data for selected days are illustrative, in order to predict the impact of RTP in other service territories, customer load response must be quantified. Table 3 summarizes the range of flexibility parameter estimates for the responding customers in different SIC categories. The amount of load shifting that occurred between days is much larger than the load shifting that occurred within days. The between day parameter is significant for both September and October for fourteen of the seventeen categories and is significant for at least one month for the remaining three categories. The interquartile range for all seventeen categories is 0.14 to 0.31 percent of the price change in September and 0.08 to 0.15 in October. The median between day flexibility parameter is 0.20 in September and 0.11 in October. The within day parameter is significant in both months for only five of the seventeen categories. In September and October the interquartile ranges for the within day flexibility parameter are 0.01 to 0.05 and 0 to 0.05 percent respectively, much lower than the between day flexibility parameter range. The median between day value is 0.02 in September and 0.01 in October.

The results from Tables 2 and 3 indicate that a higher percentage of customers are classified as responders and that the flexibility parameter estimates are greater in September than in October. This pattern is consistent with anecdotal and theoretical evidence that customers "use up" their ability to respond when high or volatile prices continue for longer periods of time since production deadlines may become more binding and inventories of intermediate or final products may be used up.

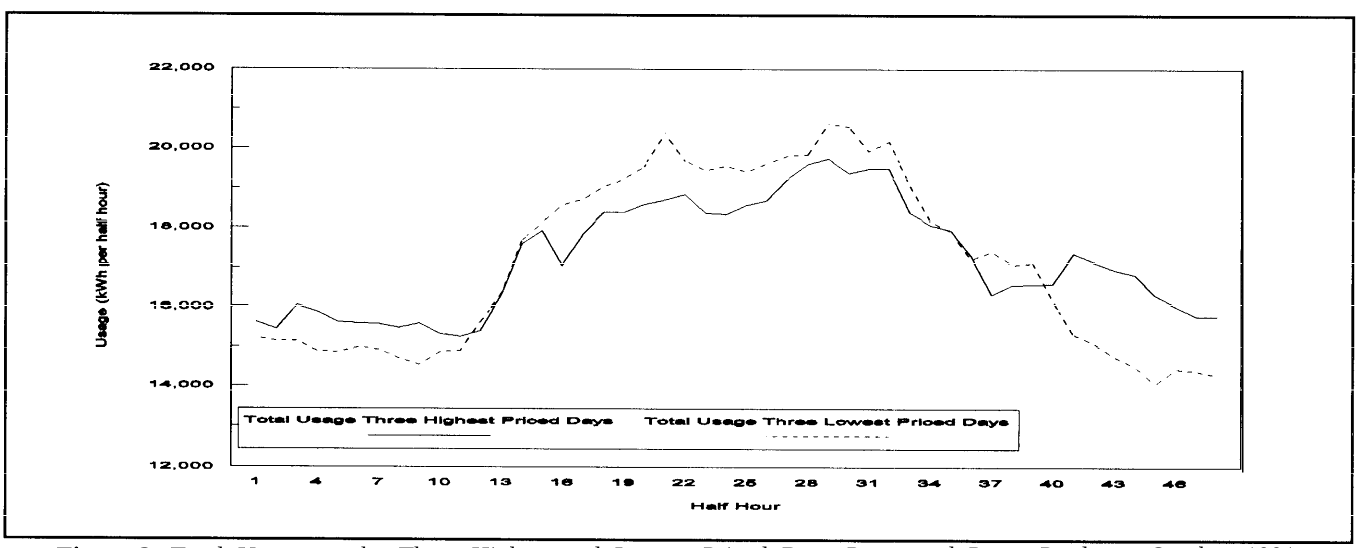

Figure 3. Total Usage on the Three Highest and Lowest Priced Days–Paper and Paper Products, October 1991

Table 3. Flexibility Parameters for Responding Customers

	25th Percentile	Median	75th Percentile
September:			
Between Day	0.14	0.20	0.31
Within Day	0.01	0.02	0.05
October:			
Between Day	0.08	0.11	0.15
Within Day	0	0.01	0.05

Load Shape Implications

The implications for load patterns of a range of flexibility parameters are illustrated in Figures 4 and 5. Starting with the average October weekday load pattern for a customer randomly selected from among the responding customers, Figure 4 graphs the simulated load patterns that are implied by a high within day and between day flexibility in October for a high price scenario and for a low price scenario. The high and low price scenarios are the average of the three highest price weekdays in October and the average of the three lowest price weekdays. Figure 5 graphs the corresponding load patterns implied by an average within day and high between day flexibility using the average September weekday load pattern for a

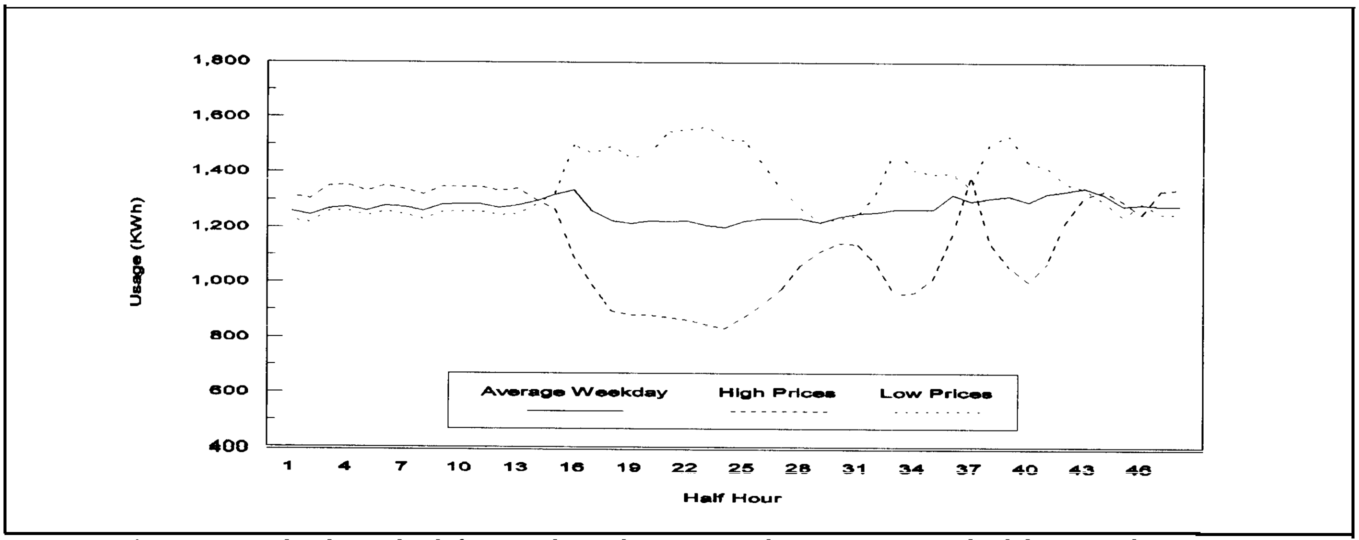

Figure 4. Simulated Load Shifting–High Within-Day, High Between-Day Flexibility, October 1991

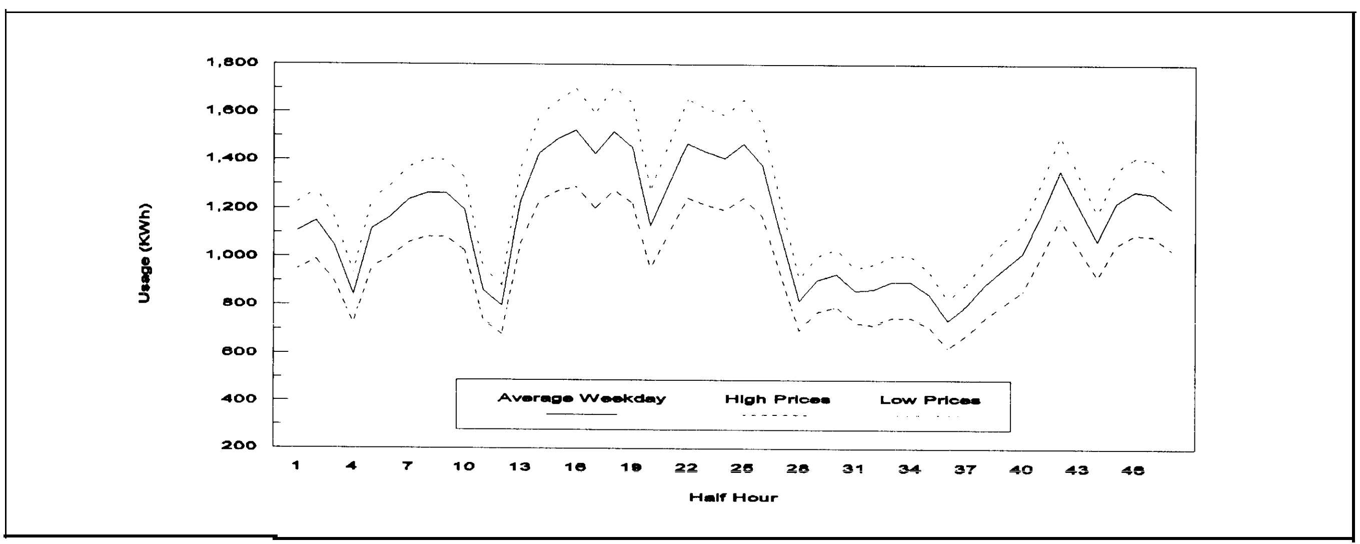

Figure 5. Simulated Load Shifting–Average Within-Day, High Between-Day Flexibility, September 1991

randomly selected responder using high and low price scenarios for September.

In Figure 4, usage for the high price scenario is reduced the most during the mid-day when prices are highest, and it is also reduced noticeably during the two evening price peaks. Likewise, usage for the low price scenario is increased the most during the mid-day, and also during the evening price peaks. Since the within day parameter is large, in the early morning and late night hours in which the prices are generally similar across scenarios, usage in the high price scenario is actually above average usage and usage in the low price scenario is below average usage. The overall usage level in the day is shifted down for the high price scenario and up for the low price scenario due to the high between day parameter.

In Figure 5, in the high price scenario the level of usage in all hours is below the average level of usage and in the low price scenario the level of usage in all hours is above the average level. This is due to the large between day parameter in comparison to the average within day parameter. There is a small amount of load shifting occurring within day. For the high price scenario the load reduction in the mid-day hours when price is highest is greater than the load reduction in the lower price hours.

Conclusions

The results indicate that between one-third and one-half of the customers respond to prices. The response differs between SIC categories and between months. The between day load shifting tends to be greater than the within day load shifting. Between day shifting ranged between .07 to .35 percent of price change while within day shifting ranged between 0 and .08 percent. It is evident that some customers are capable of responding to short-term price variation that occurs in RTP programs. As a result RTP has the potential to play an important role in matching customer load patterns with system load management requirements.

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Endnotes

1. In addition to varying by each half-hour, Midlands Electricity's pool price contract includes a "triad" demand charge. The triad demand charge of £10/kW is levied on the average level of demand during the three half-hours of system peak (known as triads), which must be separated by at least 10 days. Customers were given triad advance warnings and priority alerts by Midlands Electricity for those intervals in which Midlands Electricity thought the system was especially likely to peak. These warnings and alerts occurred during the winter months from late November to mid-February. We follow previous work that incorporates demand charges into the energy charge by "spreading" the demand charge over hours that had a high probability of being the system peak, in this case the half-hours covered by the triad warnings and alerts. The effective energy charge, which gives the expected marginal price, for each of those half-hours would be the pool price plus the ratio of the demand charge to the number of half-hours covered by the warnings and alerts.

2. The typical weekly load shape is defined for each season as the geometric mean of the load shapes for each week. For example, the geometric mean of usage in half-hour h during a day of type t (e.g. Wednesdays) is formed as:

$$\ln(\bar{E}^{g}_{th}) = \frac{1}{N_t} \sum_{m=1}^{3} \sum_{d\in t}^{30} \ln(E_{mdh})$$

where N_t is the number of days of type t in the season (months m = 1,2,3).

In addition to the seven days of the week, three additional day-types are defined: holidays, "quiet" days on which the daily mean of half-hourly usage is statistically significantly less than the daily mean usage for non-quiet days and the variance of usage within the day is less than the variance during non-quiet days, and "quiet" periods consisting of seven or more consecutive quiet days. Quiet days are designed to distinguish weekdays on which plants are shut down, wholly or partially, due to the industrial recession in Britain. Quiet periods are designed to distinguish plant shutdowns for a week or more, which in our data set, correspond to customer-specific summer holidays in July and/or August, year-end holidays, and shutdowns for retooling or other reasons.

3. Caves, Christensen, and Diewert (1982) have shown that a price index relative to the geometric mean is given by the Tornqvist price index:

$$\ln(D_d/\bar{D}^g) = \frac{1}{2}\sum_{h=1}^{48} (w_{dh} + \bar{w}_{th})\ln(P_{dh}/\bar{P}^g_{th})$$

where $w_{dh} = P_{dh}E_{dh}/[\Sigma_{k=1}^{48} P_{dk}E_{dk}]$ is the h^{th} half-hour electricity expenditure share and the bar without a superscript denotes the arithmetic mean taken over all days of type t in the season.

4. A customer is considered a responder in a given month if either the estimated within day or between day flexibility parameter is significantly greater than zero at the five percent level.

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