Chapter 16

Using Customer-Level Response to Spot Prices to Design Pricing Options and Demand-Side Bids

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Key words: Competition; Demand-Side Bids; Demand Elasticities; Forecasting; Pricing Options; Retail Pricing; Spot Pricing; Restructured Electricity Markets.

Abstract: This chapter presents estimates of customer-level demands for electricity by large and medium-sized industrial and commercial customers purchasing electricity according to half-hourly spot prices and demand charges from the England and Wales electricity market. The resulting models can be used to measure demand-altering effects arising from the imposition of arbitrary time varying and consumption-dependent energy and demand pricing structures, including alternative levels of supply reliability/interruptibility and stability or certainty of prices. Knowledge of customer-level electricity demands is critical to success in the evolving competitive business environment, as well as for the success of restructured electricity markets as a whole. Such knowledge is required to effectively forecast customer price responsiveness and demands, design pricing options to attract and maintain a profitable portfolio of customers, and demand-side bid to build a price response into the market demand used to determine market-clearing electricity and ancillary services prices.

1. INTRODUCTION

Electric utilities in the U.S. and worldwide are faced with dramatic changes in market structure and regulations governing their form and operations. Such restructuring is intended to provide incentives for efficient pricing, investment, and operations by introducing competition into these markets. The predominant view is that competition is feasible for structurally or functionally separated firms generating (wholesale) and/or supplying (retail) electricity, while network services (transmission and distribution) are most efficiently provided by open access firms facing alternative (to cost-based) forms of regulation (e.g., price caps). Examples of this view include the England and Wales (E&W) and California electricity markets.[i] These changes in market structure and rules lead to some rather dramatic changes in the operations of electric utilities relative to the regulated integrated monopoly status of the past.[ii] Prospering in this new environment will require utilities to develop comprehensive strategies aimed at matching profitable service options to diverse customer needs. Knowledge of customer-level electricity demands is critical to success in the evolving competitive business environment, as well as for the success of restructured electricity markets as a whole. Such knowledge is required to effectively:

- Forecast customer price responsiveness and demands.
- Design pricing options to attract and maintain a profitable portfolio of customers.
- Demand-side bid to build a price response into the market demand used to determine market-clearing electricity and ancillary services prices.

A difficulty in restructured electricity markets has been the lack of a demand response in the price determination process in wholesale markets. Demand-side bidding is important in order to introduce a price response into the price-determination process in markets such as the E&W (which currently uses a perfectly inelastic day-ahead demand forecast in determining each half-hour's market price). A difficulty in incorporating a demand-side into the price determination process has also been that few consumers face prices that vary with the half-hourly wholesale price of electricity. Customers are not provided with incentives for efficient conservation and substitution of electricity away from peak periods if they do not face half-hourly prices that reflect the real-time cost of purchasing wholesale electricity. This can have adverse consequences for system reliability, particularly during peak demand periods, when the transmission and distribution network becomes extremely stressed.

Accurate measurement of the within-day price response of customers is an important necessary ingredient for any electricity retailer to aggressively demand-side bid into a wholesale electricity market. Active demand-side participation builds a price-response into the market price-setting process, which leads to less capacity being called upon to generate in response to higher bids by generators. Benefits to retailers from significant demand-side bidding include the reduced magnitude and variability of market prices and decreased costs of contracts protecting retailers (selling to customers at fixed prices) from relatively large market prices.

Setting retail prices for electricity in restructured markets is complicated by the fact that customers now will have their choice among suppliers. Moreover, suppliers have limited information on the load characteristics of customers, particularly new ones, including those that may be attracted from other retailers.[iii] This lack of information has always existed in regard to new utility customers. However, in the new competitive retail environment, cross-subsidizing certain customers at the expense of others is no longer viable because the customers providing subsidies can now purchase from another supplier. If the supplier sets too high a price, existing and potential customers will choose to purchase their electricity from a competitor. Conversely, setting the price too low will at least imply foregoing available profit, and possibly lead to the extreme of subsidizing the customer's electricity consumption. Understanding the structure of customer-level demand is necessary to effectively design pricing options in markets with competition. Even if all competitors have exactly the same costs, the supplier with superior information concerning customer demands over time will be able to design pricing options which attract and maintain a profitable collection of customers, at the expense of less well-informed suppliers.

The supplier with superior demand information will also be able to more accurately forecast future customer demands, which remains necessary for planning and investment. Forecasting customer demands is necessary in restructured markets for all of the reasons forecasts were made in past. Precise forecasts are even more critical because utilities are unlikely to be able to pass on the cost of all load shape forecast errors on to customers who now have a choice of suppliers. In a competitive retail market, forecast errors will be absorbed largely by utility shareholders.

This chapter presents some of the results and implications of our estimates of customer-level demands, which are fully developed in Patrick and Wolak (1997, 1999). In these reports we estimate customer-level demands for electricity by large and medium-sized industrial and commercial customers purchasing electricity according to half-hourly spot prices from the E&W electricity market.[iv] The E&W market was established in 1990 and has served as a model for restructuring worldwide.

The demand models developed and estimated in Patrick and Wolak (1997, 1999) quantify the extent of intertemporal substitution in electricity consumption between pricing periods within the day due to changes in the E&W pool prices, and distinguishes between the demand-altering effects of changes in pool prices and changes in demand charges. These customer-level demand relationships are essential in the design of pricing options to attract and maintain customers in a market with competing suppliers. They can be used to measure the demand altering effects arising from the imposition of arbitrary time varying and consumption-dependent pricing structures. In particular, the models can be used to forecast customer-level electricity loads, revenues from electricity supply, and customer benefits under alternative rate structures; estimate the own-price and cross-price elasticities, which can be used in rate simulation and optimization programs; forecasting; and develop demand-side bids.

The remainder of this chapter proceeds as follows. In the next section we describe the spot price determination, contracts based on these prices, and the data used to estimate the model. Section 3 discusses the impossibility of predicting price responsiveness of customers in restructured markets using aggregate data. This is followed by a discussion of the price elasticity estimates for a sample of these customers in Section 4. Section 5 contains brief examples to illustrate how the econometric model could be used to compare alternative pricing structures and to implement demand-side bidding. This chapter closes with a discussion of future research on designing pricing options and demand side bids under competition.

2. SPOT PRICES AND POOL PRICE CONTRACTS

Generators offer prices at which they will provide various quantities of electricity to the E&W pool during each half-hour of the following day. These prices and quantities submitted by generators are by the National Grid Company (NGC) to determine the merit order of dispatching generation and reserve capacity. NGC computes a forecast of half-hourly system demands for the next day. The system marginal price (SMP) for each half-hour of the next day depends on the price bid on the marginal generation unit required to satisfy each forecast half-hourly system demand for the next day. For each day-ahead price-setting process, the 48 load periods within the day are divided into two distinct pricing-rule regimes, referred to as Table A and Table B periods. During Table B periods, the SMP is equal to the bid price of the last generating facility necessary to meet NGC's forecast of demand for that half-hour. In Table A periods, average start-up and no-load costs over an expected dispatch horizon are added to bid prices to produce adjusted offer prices and the SMP is the least adjusted bid price necessary to meet NGC's forecast of total system load.[v] The SMP is one component of the price paid to generators for each MWh of electricity provided to the pool during each half-hour.

The price paid to generators per MWh in the relevant half-hour is the Pool Purchase Price, defined as PPP = SMP + CC. CC is the capacity charge, where CC = LOLP×(VOLL - SMP), LOLP is the loss of load probability, and VOLL is the value of lost load. SMP is intended to reflect the operating costs of producing electricity (this is the largest component of PPP for most of the half hour periods). VOLL is set for the entire fiscal year to approximate the per MWh willingness of customers to pay to avoid supply interruptions during that year. VOLL was set by the regulator at 2,000 £/MWh for 1990/91 and has increased annually by the growth in the Retail Prices Index (RPI) since that time. The LOLP is determined for each half-hour as the probability of a supply interruption due to the generation capacity being insufficient to meet expected demand. The PPP is known with certainty from the day-ahead perspective.

The pool selling price (PSP) is the price paid by suppliers purchasing electricity from the pool to sell to their final commercial, industrial and residential customers. During Table A, half-hours the PSP is:

$$\mathrm{PSP} = \mathrm{PPP} + \mathrm{UPLIFT} = \mathrm{SMP} + \mathrm{CC} + \mathrm{UPLIFT}.$$

UPLIFT is a per MWh charge which covers services related to maintaining the stability and control of the National Electricity System and costs of supplying the difference between NGC's forecast of the day's demands and the actual demands for each load period during that day, and therefore can only be known at the end of the day in which the electricity is produced. These costs are charged to electricity consumption only during Table A periods in the form of this per MWh charge. The *ex ante* and *ex post* prices paid by suppliers for each megawatt-hour (MWh) are identical for Table B half-hours, (i.e., PSP = PPP for Table B periods). Thus, the only energy price uncertainty from the day-ahead perspective is the UPLIFT component of the PSP, which is only known *ex post* and only applies to the Table A half-hours.[vi]

By 4 PM each day, the Settlement System Administrator (SSA) provides Pool Members, which includes all of suppliers, with the SMP, CC, LOLP, and identity of the Table A and B pricing periods.

Data from a supplier in this market, Midlands Electricity plc (MEB), over the fiscal years[vii] 1991-1995 was used to estimate half-hourly customer-level demand functions under MEB's real-time pricing program—what MEB calls a Pool Price Contract (PPC).[viii] Under this pricing option, customers are charged according to half-hourly spot prices that clear the E&W electricity market—the PSP. As discussed above, the PSP for each half-hour of a day is to a large part known from the day-ahead perspective, but only known with certainty thirty days *ex post* of actual consumption. PPC customers also face a demand charge (termed a "triad charge" in the E&W market) on the average kWs consumed during the three half-hours coincident with the largest E&W transmission system demands.[ix] The PPC was first offered at the beginning of the second fiscal year of the E&W market to allow consumers with peak demands greater than 1 MW to assume the risks of pool price volatility and therefore allows the electric retailer to avoid the costs associated with hedging against wholesale price uncertainty. Under the PPC, wholesale electricity costs for both energy and transmission services are directly passed through to the customer. For traditional pricing contracts, the Supplier absorbs all the wholesale price risk associated with the PSP, and retails it to final consumers according to fixed and deterministic prices (i.e., they do not vary with the PSP).

The peak demand size limit on customers given the option to choose their supplier as well as purchase according to a PPC was reduced to 100 KW in 1994, coinciding with the same limit change in the definition of franchise customers. This size limit has been phased out over 1998 and 1999 so that the entire supply segment of the electricity market is open to competition. Any customer willing to pay the cost of installing meters capable of recording half-hourly consumption now has the option to pay for electricity according to pool prices. Patrick and Wolak (1997 and 1999) provide the number of customer/year pairs in each BIC class (by two-digit BIC code), as well as a general description of the industries contained in each class, for our sample of 263 business lines comprising our sample of commercial and industrial customers.[x]

The expected PSPs for all forty-eight half-hourly intervals beginning with the load period ending at 5:30 A.M. the next day until the load period ending at 5:00 A.M. the following day are faxed to all pool price customers immediately following the supplier's receipt of the SMP, CC and the identity of the Table A and Table B periods from NGC.[xi] The supplier develops forecasts of the UPLIFT component of the PSP for Table A half-hours and provides these with the forty-eight half-hourly SMPs and CCs. The PSP reported in this fax is equal to the PPP in Table B periods and the sum of the REC's estimate of the UPLIFT and the PPP in Table A periods. The actual (*ex post*) PSP paid by electricity consumers on the PPC for Table A periods is known twenty-eight days following the day the electricity is consumed. The actual or *ex post* PSP is equal to the *ex ante* PSP for Table B periods because the UPLIFT is known to be zero in these load periods. We also collected the information contained on the faxes sent to each PPC customer the day before their actual consumption occurs. In addition, we collected information on the actual value of UPLIFT for our sample period. Table 1 gives the sample means and standard deviations for the various components of the PSP for each fiscal year during our sample.

Table 1. Sample Means and Standard Deviations of Components of PSP

	Fiscal Year	Mean	Std Dev
SMP	1	19.52	4.10
CC	1	1.29	8.76
UPLIFT	1	1.61	2.31
PSP	1	22.42	12.72
SMP	2	22.64	4.24
CC	2	0.17	1.70
UPLIFT	2	1.39	1.12
PSP	2	24.19	5.75
SMP	3	24.16	6.71
CC	3	0.28	2.97
UPLIFT	3	2.18	1.62
PSP	3	26.62	8.76
SMP	4	20.78	12.28
CC	4	3.22	24.49
UPLIFT	4	2.38	4.53
PSP	4	26.38	35.08

Customers on PPCs also pay a demand charge. This £/MW triad charge is levied on the average capacity used by each PPC customer during the three half-hour load periods ("triads") in which the load on the England and Wales system is highest, subject to the constraint that each of these three periods is separated from the others by at least ten days. The precise triad charge is set each year by NGC (subject to their RPI-X price cap regulation).

The triad charge faced by these PPC customers was 6,150 £/MW for fiscal year 1991/92, 5,420 £/MW for 1992/93, 10,350 £/MW for 1993/4, and 10,730 £/MW for 1994/95.

There are various mechanisms that suppliers use to warn their PPC customers of potential triad periods. *Triad advance warnings* are generally faxed to consumers on Thursday nights and give the load periods during the following week that the supplier feels are more likely to be triad periods. *Triad priority alerts* are issued the night before the day that the supplier considers the probability of a triad period to be particularly high. These alerts also list the half-hours most likely to be triad periods. To mitigate the incentive for suppliers to issue triad priority alerts, the regulatory contract allows a maximum of twenty-five hours of priority alerts each fiscal year. Historically, all triad charges have occurred in the four-month period from November to February.[xii] The actual price for service paid by PPC customers also contains various other factors, not related to the pool prices, which are analogous to charges fixed rate customers face.[xiii]

3. THE IMPOSSIBILITY OF USING AGGREGATE DATA TO ESTIMATE PRICE RESPONSIVENESS

The price determination process in the E&W market does not use the actual market demand to set the two largest components of the PSP, the SMP and CC. As discussed in Section 2, these prices are set using a perfectly inelastic (with respect to price) forecast of the market demand for each half-hour of the next day. In addition, few customers pay for electricity during any half-hour at the PSP or even at prices that vary with the PSP throughout the day, month, or year. Consequently, any attempt to estimate a relationship between the PSP for a given half-hour and the total system load for that half-hour should not recover the true relationship between final demand and the half-hourly market price for any customer or group of customers, because the actual PPP is set by NGC's forecast of total system load and not actual total system load.

A notable feature of the behavior of the PSP is its tremendous variability, even over very short time horizons. For example, the maximum ratio of the highest to lowest PSP within a day is 76.6, whereas the average of this ratio over all days in our sample period is about 4.1. The maximum ratio of the highest to lowest PSP within a month is 107.5 and the average of this ratio over all months in our sample is 11.0. Finally, the maximum ratio of the highest to lowest PSP within a fiscal year is approximately 117.8.

The E&W total system load (TSL) exhibits dramatically less volatility according to this metric. For example, the maximum ratio of the highest to lowest TSL within a day is 1.89 and the average over all days in the sample is 1.49. Within a month, the maximum of the highest to lowest TSL is 2.38 and the average over all months in the sample is 2.04. Over a fiscal year, the maximum ratio of the highest to lowest TSL is 3.08. Defining forecasting accuracy as the standard deviation of the forecast error as a percent of the sample mean of the time series under consideration, consistent with this difference in volatility, the TSL can be forecasted much more accurately over all time horizons than the PSP.

Comparing the time path of PSP to the time path of total system load bears out our logic for the impossibility estimating price responsiveness using aggregate data. Figure 1 (below) plots the half-hourly PSP in (£/MWh) and Figure 2 (below) plots the half-hourly TSL in gigawatts (GW) of capacity for the more than 17,000 periods for each fiscal year during our sample period. All of the price graphs are plotted using the same scale on the vertical axis to illustrate the tremendous increase in magnitude and volatility of the PSP over the fiscal years. The highest values of PSP within a fiscal year tend to occur November through February. These are also the months when there is an enormous amount of price volatility within and across days. The pattern and the magnitude of this volatility differ markedly across the four fiscal years in our sample.

Compared to the four graphs in Figure 1, the four graphs in Figure 2 indicate the very predictable pattern of TSL across days, weeks, and years. In particular, the total demand in a single day in one year is very similar to the demand in that same day in the previous year. The cycle of demand within a given week is similar to the cycle of demand within that same week in another year. Similar statements can be made for the cycles in TSL within months across different years.

The difference between the four price graphs and the four TSL graphs illustrates a very important implication of the operation of the E&W market which prevents a meaningful price-response from being recovered from co-movements in TSL and the PSP. Despite the large differences in the patterns of PSP movements, there is no discernable change in the pattern of TSL. This results from the fact that the vast majority of commercial and industrial customers, and all residential customers, purchase power on fixed-price contracts set for the entire fiscal year. These customers do not face any within-year price changes or even within-day price changes that depend on within-year changes in the PSP that might trigger a within-day demand response. In addition, NGC's forecast of TSL, not actual TSL, determines the half-hourly PPP.

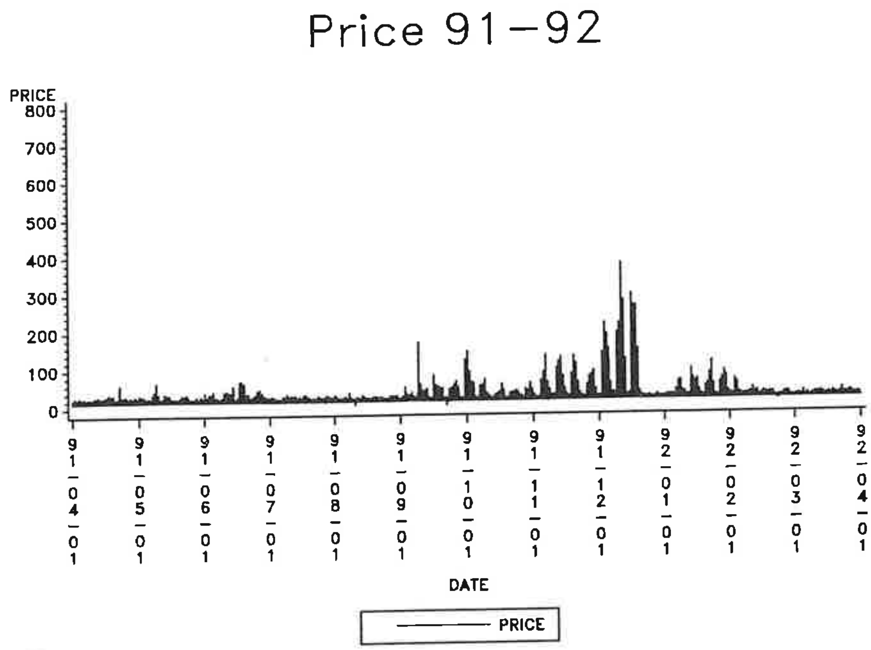

Figure 1(a). Pool Selling Prices, April 1991 – March 1992.

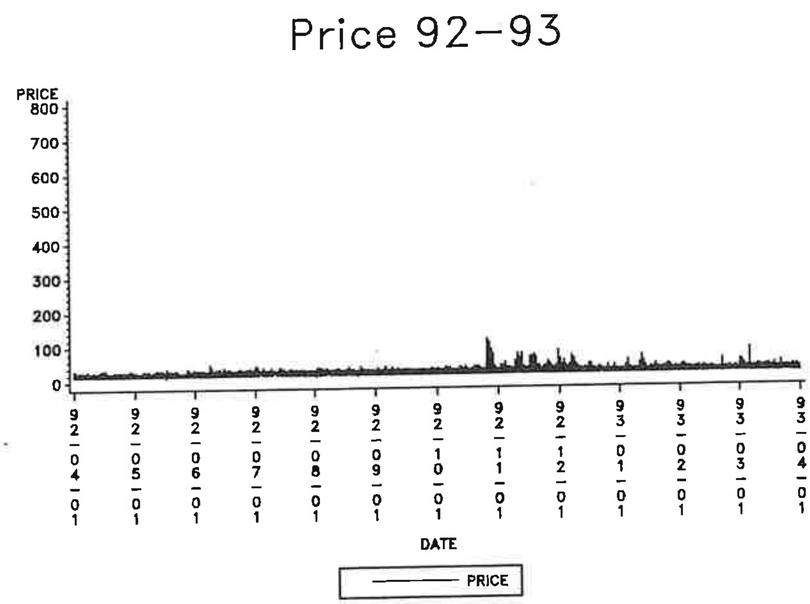

Figure 1(b). Pool Selling Prices, April 1992 – March 1993.

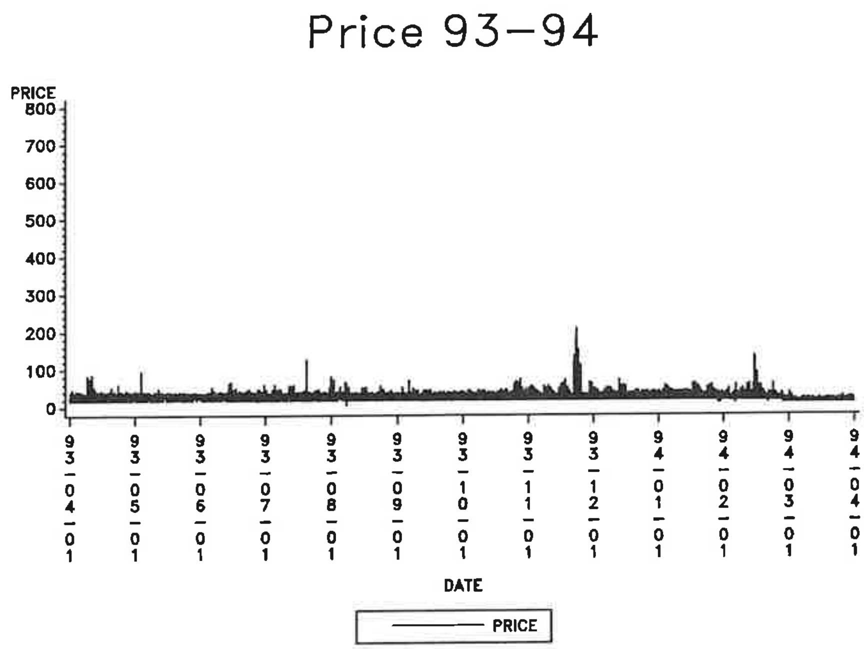

Figure 1(c). Pool Selling Prices, April 1993 – March 1994.

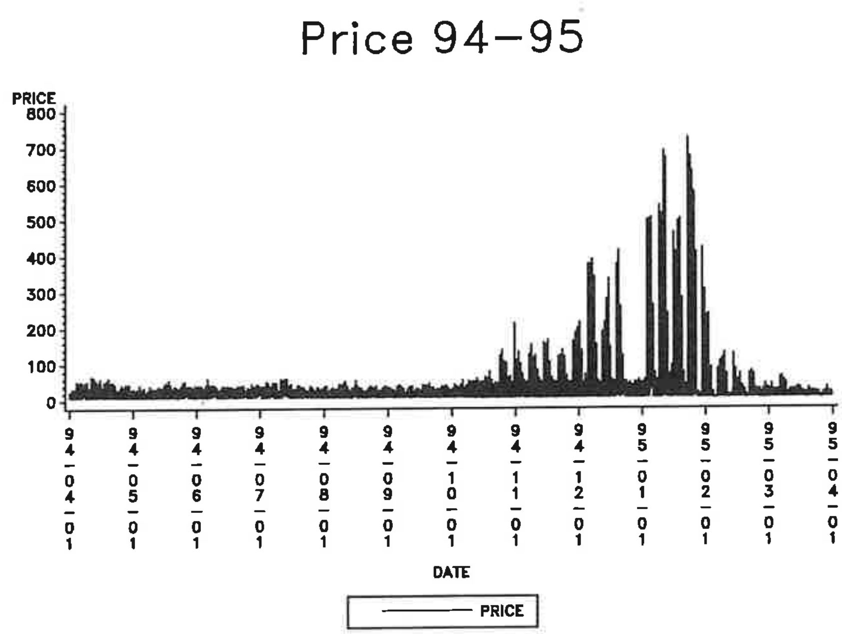

Figure 1(d). Pool Selling Prices, April 1994 – March 1995.

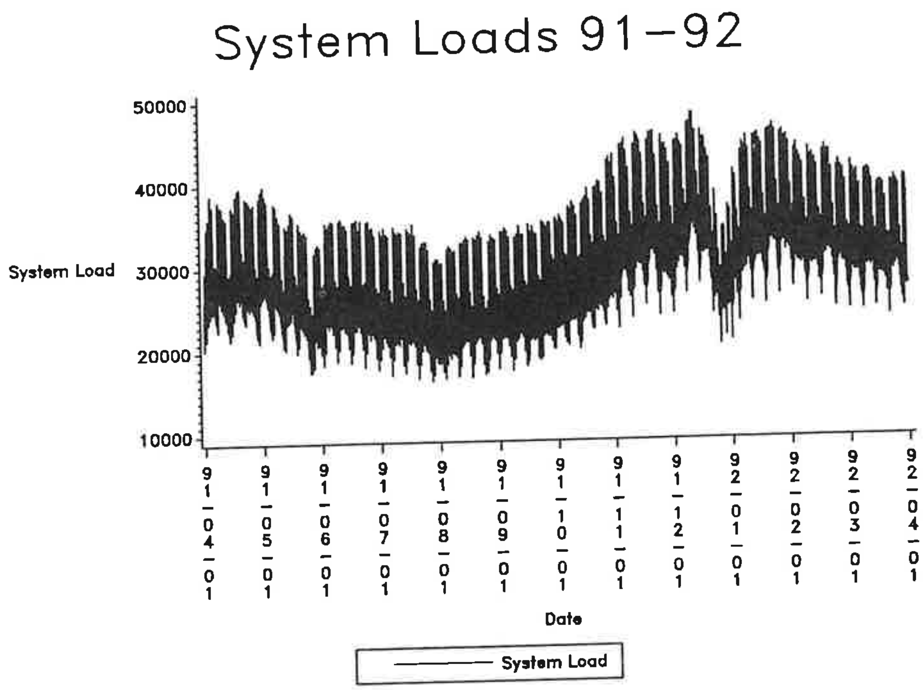

Figure 2(a). Total System Loads, April 1991 – March 1992.

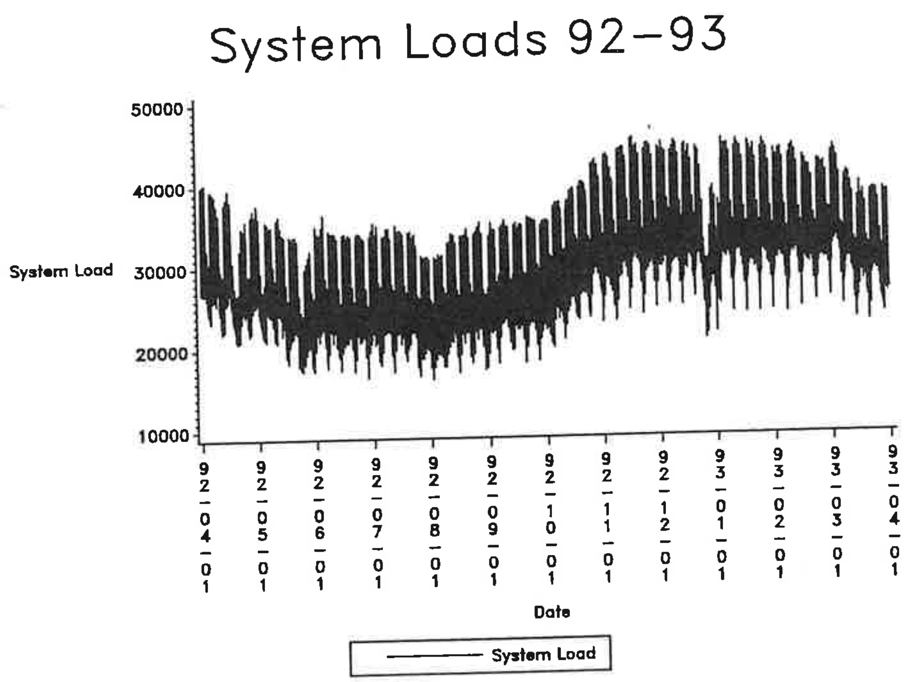

Figure 2(b). Total System Loads, April 1992 – March 1993.

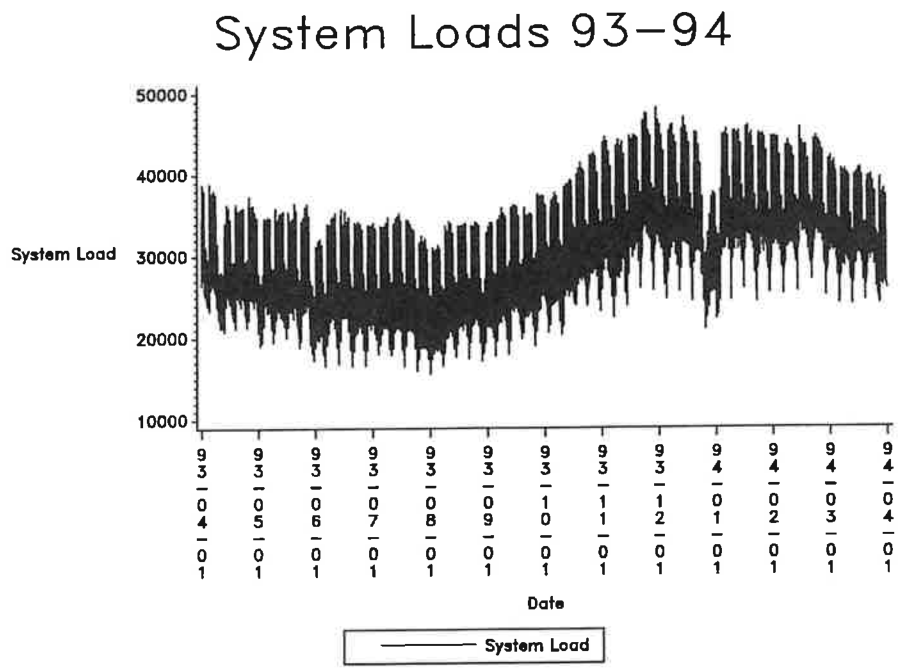

Figure 2(c). Total System Loads, April 1993 – March 1994.

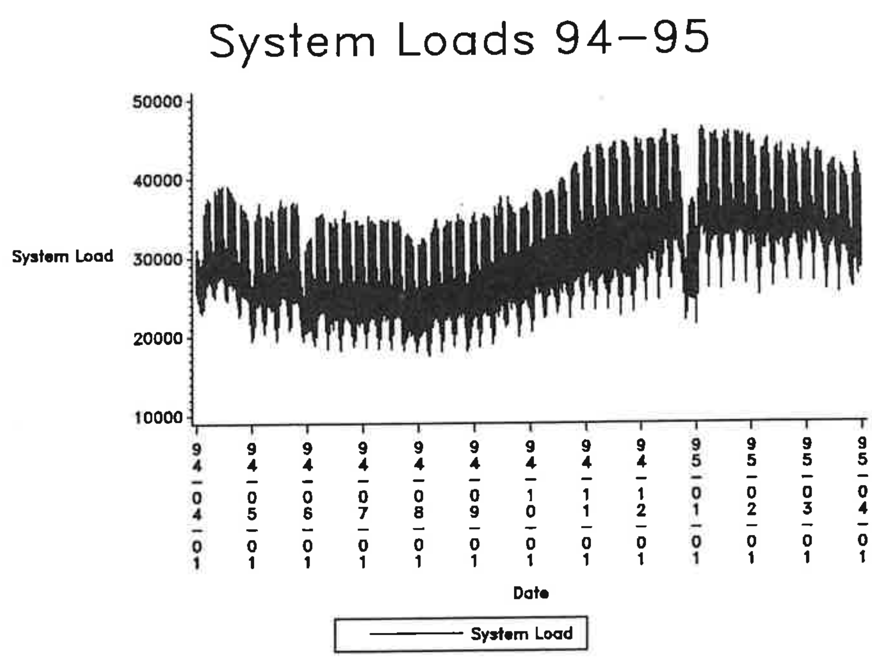

Figure 2(d). Total System Loads, April 1994 – March 1995.

The pricing structures under which consumers pay for electricity have important economic implications for how the supplier chooses to purchase and/or produce the electricity demanded. Although electricity at any particular time is a homogeneous good, the reliability of prices and supply, as well as the relative magnitudes of prices they face, are important characteristics of the pricing structures from which consumers choose. Since suppliers provide electricity to most of their customers at rates fixed well in advance of the realization of pool prices, they normally hedge against this price volatility by purchasing contracts for differences (CFDs). CFDs are financial instruments hedging electricity price volatility. CFDs come in various forms–one-sided, which hedge only against price risk in one direction or two-sided, which hedge against both upward and downward price risk. See Wolak and Patrick (1996, 1997) for further detail. CFDs have been sold by generators as well as financial institutions and traders that deal in commodity markets and derivatives.[xiv] They are not contracts to deliver electricity and do not cover all price uncertainty. For retail customers under the PPC, the supplier does not face any risk from pool price fluctuations since the customer has assumed this risk, hence the supplier would avoid this risk (and the costs of CFDs to cover any of this risk). Conversely, under a fixed-price contract, a customer faces no price uncertainty and the supplier faces all of the PPP risk, unless CFDs are purchased. These fixed prices must include a premium, relative to spot prices, to cover the costs of the risk the supplier faces and that which is covered with CFD purchases.

Each supplier offers several fixed-price options to electricity consumers. For residential customers, suppliers offer a small number of different standard price contracts, (e.g., the single-price for all load periods contract, or a two-price contract) (separate prices for day and night load periods). For business customers, each supplier offers several standard price contracts, but particularly for very large customers, price contracts are often negotiated on a customer-by-customer basis. Consequently, for the same half-hour period, there are hundreds and potentially even thousands of different retail prices that different customers throughout the E&W system are paying for electricity. In addition, movements in the PSP, or in any of its components, generally have no effect on the movements in these contract prices for the duration of the contract period, usually a fiscal year. The lack of responsiveness of TSL to changes in PSP does not imply that individual customers do not respond to price changes. This lack of responsiveness is indicative of the fact that only a very small fraction of final customers purchase electricity at the half-hourly PSP, with the remaining vast majority purchasing electricity on the fixed-price contracts described above and the fact that forecast TSL, not actual TSL, sets the market-clearing value of PPP.

An important consequence of these two facts is that it makes little, if any, economic sense to estimate an aggregate demand curve for electricity involving PSP or PPP as the price variable and actual TSL as the quantity demanded variable to recover a price-response. Movements in the half-hourly or the daily average PSP or PPP, which identify the aggregate price response, are irrelevant to the vast majority of electricity consumers who instead face prices that are unrelated to any within-year movements in the PSP or PPP for the entire fiscal year. Consequently, a price response recovered from regressing the current value of the TSL on the PSP for that load period is likely to be extremely misleading about the true potential aggregate price response because only between 5 and 10 percent of TSL is purchased at PSP and the remaining is purchased according to prices that are invariant to changes in the PSP for an entire fiscal year.

To estimate the within-day electricity demand response to within-day changes in the PSP requires a sample of customers actually purchasing electricity at prices that move with changes in the half-hourly PSP. PPC customers are ideally suited to this task because the within-day relative prices that they pay for electricity are based on the half-hourly PSP.

As discussed in Wolak and Patrick (1997), the major source of the large values of the PSP over the years shown in Figure 1 is the CC, which is known with certainty on a day-ahead basis. In addition, large values of the UPLIFT tend to occur in the same load periods within the day that large values of CC occur, which makes forecasting UPLIFT relatively easier. Nevertheless, the two largest components of the PSP are known to the customer before consumption choices are made for the following day, and the remaining component is forecastable with considerable accuracy. For example, the sample mean over our four years of data of the half-hourly difference between the supplier's *ex ante* forecast of UPLIFT and the actual *ex post* value of UPLIFT is 0.07 £/MWh with a standard deviation of 1.16. The mean absolute deviation of the half-hourly difference between the supplier's *ex ante* forecast of UPLIFT and the actual *ex post* value of UPLIFT is 0.56 £/MWh with a standard deviation of 1.02. Comparing these magnitudes to the annual means of the PSP given in Table 1, which are on the order of 25 £/MWh, shows that the uncertainty between the *ex ante* and *ex post* values of the PSP is relatively small from the day-ahead perspective. Of course there is still the uncertainty associated with the demand charge.

4. ESTIMATED PRICE ELASTICITIES

In this section we present mean price elasticities for firms across several industries in the E&W market. Patrick and Wolak (1999) provide the complete modeling analyses and results for these and the other industrial and commercial industries in our sample of PPC customers. Because prices and demands are extremely variable over the course of the year and within the day, there is considerable amount variability both within the day and across days in these own- and cross-price elasticities. In addition, these elasticities also vary across days due to weather differences across days. The own-price and cross-price elasticities of demand for any day and load period can be computed from the models in Patrick and Wolak (1999).

Given the amount of price volatility in the PSP and the expected demand charge, even the smallest half-hourly within-load-period own-price elasticities of demand can imply significant load reductions in response to price increases. Recall the enormous volatility in the PSP shown in Figure 1. In addition to this variability, the volatility in the expected demand charge should be taken into account in determining consumer loads.[xv] In particular, it would not be unusual to have values of expected prices across days for the same load period that differ by a factor 20 or 30, which would imply a substantial reduction in the within period demand. Table 1 gives the sample mean and standard deviation of expected half-hourly prices for our four years of data. For some load periods, the standard deviation of the expected price is more than three times the value of mean, which indicates the potential for an enormous amount of variability in prices for the same load period across days.[xvi]

Firms in the water supply industry pump substantial amounts of water into storage and sewage-treatment facilities once or twice a day. These firms generally have the ability to shift this activity to the lowest-priced load periods within the day at very short notice. As expected, there is a considerable amount of heterogeneity across the pattern of within-day price responses, as well as across the firms in this industry. Figure 3 plots the sample mean own-price elasticities as a function of the load period for two firms in the water supply industry. Although during the usual peak total system load periods, 2:30 PM to 6:00 PM (load periods 20 to 26), we find relatively small mean own-price elasticities for these periods, ranging from .06 to .26 in absolute value. For the load periods immediately preceding and following this time period, the mean own-price elasticities increase rapidly to as large as 0.86, in absolute value. This implies, for example, a 1 percent increase (decrease) in price during a pricing period may lead to as much as a 0.86 percent decrease (increase) in electricity consumed in that period. In the next section we provide an example of load shifting in the water supply industry in response to price changes.

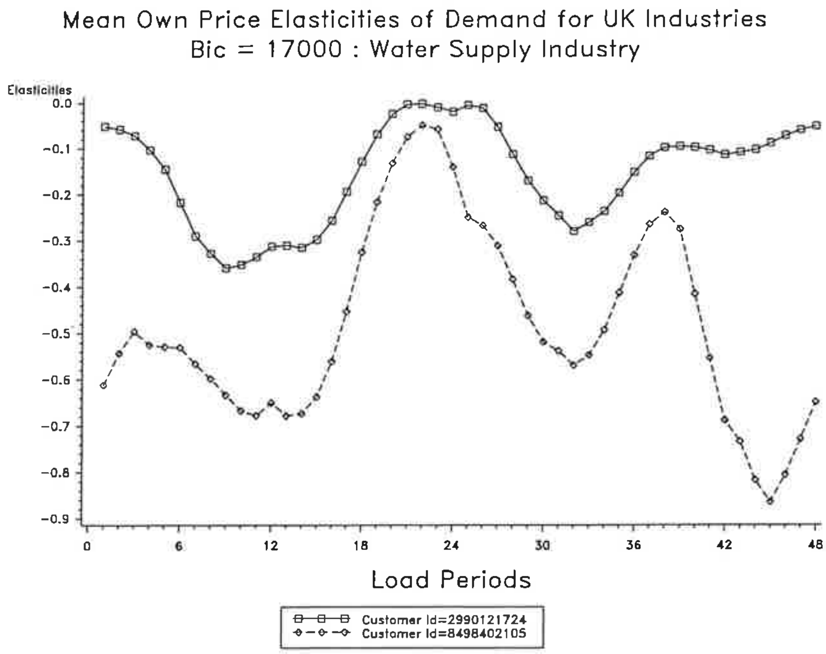

Figure 3. Mean Own Price Elasticities for Water Supply Firms.

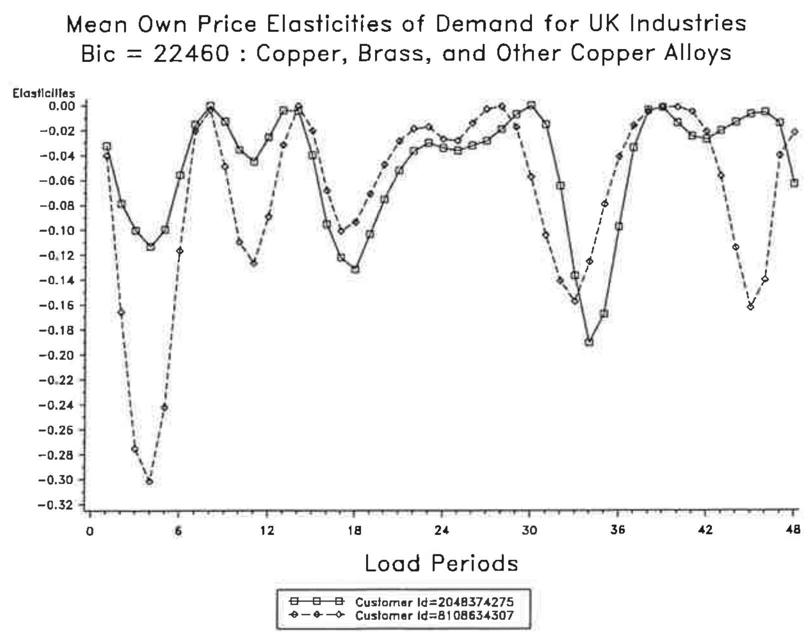

Figure 4. Mean Own Price Elasticities for Copper, Brass, and Other Copper Alloys Manufacturing Firms.

Figure 4 plots the sample mean own-price elasticities as a function of the load period for firms in the copper, brass, and other copper alloys manufacturing industry. Again, during the usual peak total system load periods, beginning at 2:30 PM and ending at 6:00 PM, we find a uniform and relatively small mean own-price elasticity. For the load periods immediately preceding and immediately following this time period, the mean own-price elasticity is over 0.2 in absolute value and gets as large in absolute value as 0.3 in load period 4, the period from 6:30 to 7:00 AM. Although these firms are characterized by significantly smaller mean own-price elasticities relative to the water industry, these elasticities still indicate substantial load response to prices, particularly when considering variability in the PSP and expected demand charge, as discussed above.

Figure 5 presents the analogous information for the seven firms in hand tools and finished metals goods manufacturing industry. Figure 6 presents this information for five customers in the steel tubes manufacturing industry. Figure 7 represents the timber and wooden furniture manufacturing industry. Finally, Figure 8 presents the own-price elasticities for the food, drink and tobacco manufacturing. Figures 3 through 8 are indicative of the range and variability of mean own-price elasticities of firms within and across various industries in the E&W market. Patrick and Wolak (1999) present further details and analyses for these industries, as well as for the remaining industries in our data set. We next provide two examples of how this type of demand information can be used in restructured electricity markets.

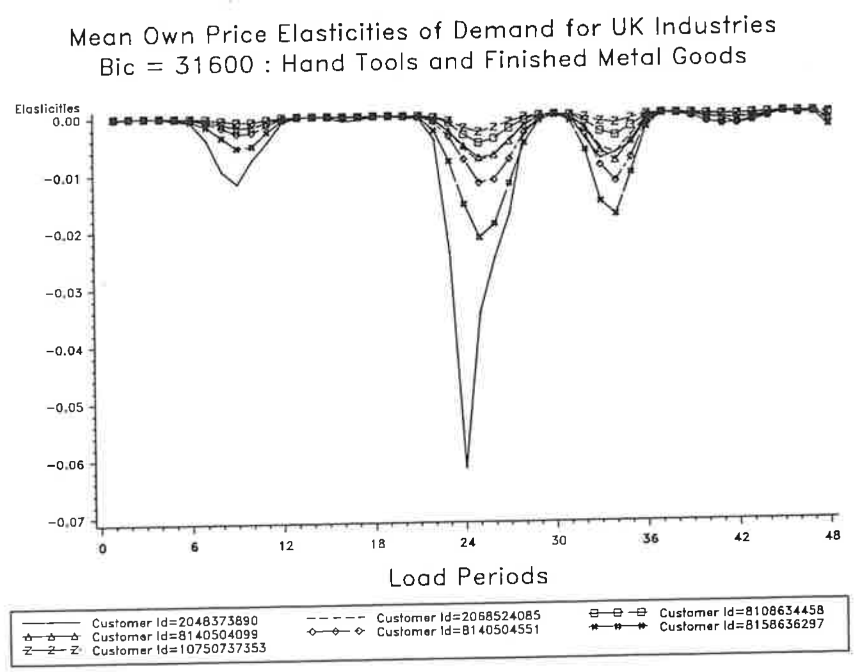

Figure 5. Mean Own Price Elasticities for Hand Tools and Finished Metal Goods Manufacturers.

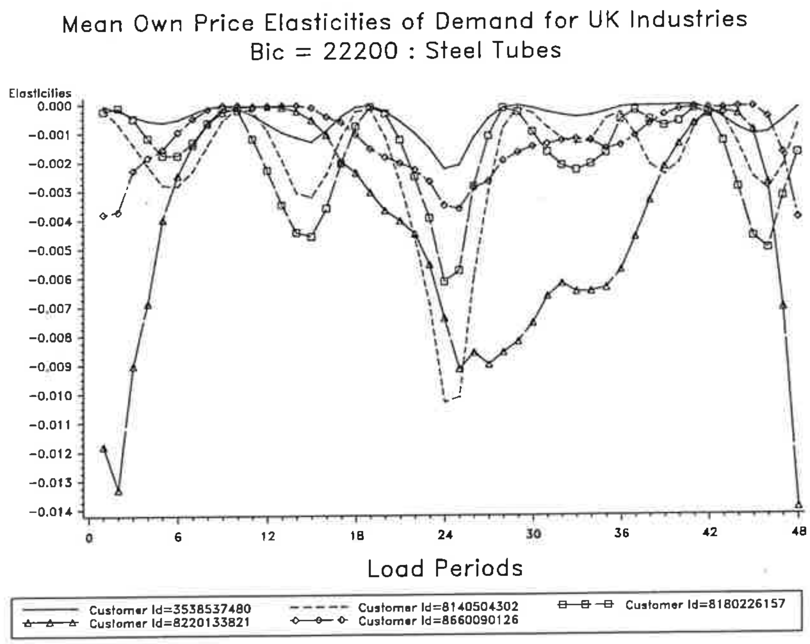

Figure 6. Mean Own Price Elasticities for Steel Tubes Manufacturing Firms.

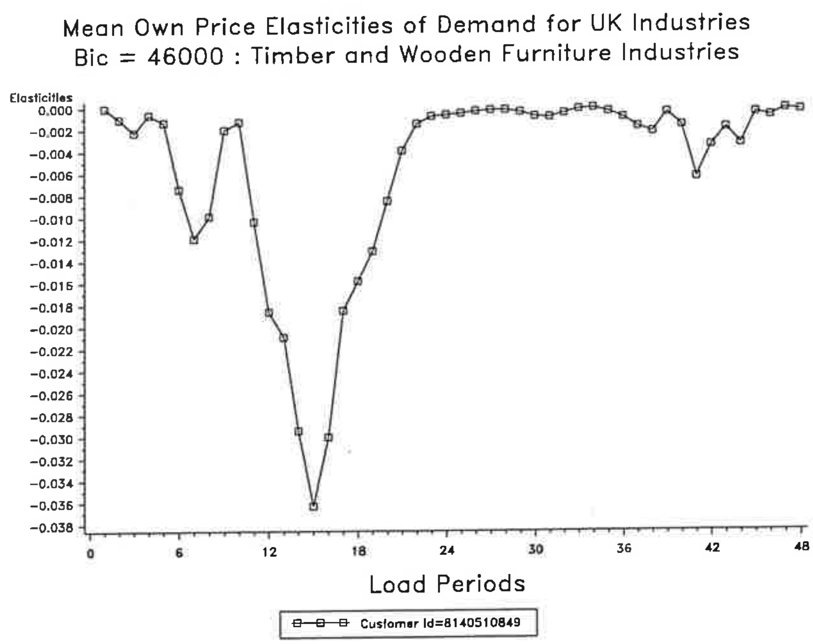

Figure 7. Mean Own Price Elasticities for Timber and Wooden Furniture Manufacturing Firms.

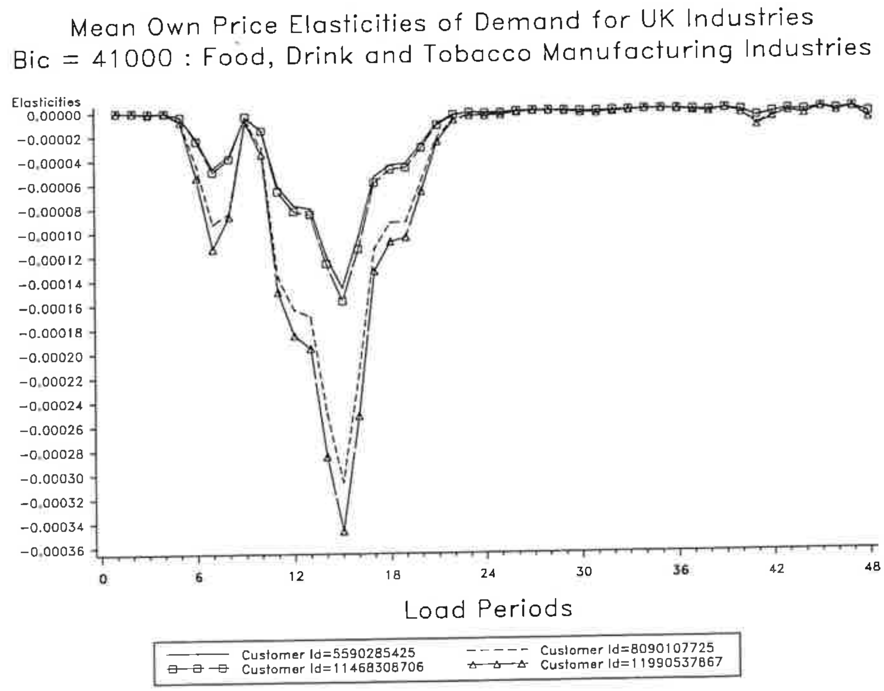

Figure 8. Mean Own Price Elasticities for Food, Drink, and Tobacco Manufacturing Firms.

5. USE OF MODEL RESULTS: TWO EXAMPLES

These demand system estimates enable the measurement of the effects of alternative time-varying and consumption-dependent pricing structures on customer-level electricity loads and the resulting effects on the electricity supplier's revenue and customer's benefits. There are many examples we could present illustrating various uses of the model but, for conciseness, we restrict ourselves to two in this section, and discuss additional uses in the conclusions of this chapter. See Patrick and Wolak (1997, 1999) for additional examples, as well as detail and the procedures used in constructing the following examples. We first present examples comparing alternative vectors of energy price and demand (triad) charge changes. We then present an example where we use this procedure to develop demand-side bids derived from changes in the real-time pricing (PPC) customers' demands as a result of price changes.

We first use the model to predict the demand response to changes in various components of the expected prices—the sum of expected PSP and the expected demand charge. Figure 9 considers two changes in the expected PSP. The baseline scenario is the pattern of consumption for a representative weekday evaluated at the sample mean of the observed expected prices. The first scenario is a 50 percent increase in all forty-eight half-hourly expected PSPs holding the expected demand charges constant. Consistent with the own-price elasticities, we find significant reductions in demand relative to the baseline scenario in load periods early in the day and later in day with only a small reduction in demand during the high priced periods of the day. The second scenario decreases the expected PSPs in load periods 30-34 by 50 percent. Significant increases in the electricity consumption are predicted in these load periods, with very small reductions in consumption predicted in the immediately adjacent periods.

The second two scenarios, which are given in Figure 10, consider the impact of changes in components of the expected demand charge the pattern of within-day electricity consumption. The first considers a 20 percent decrease in the demand charge. The representative day selected for this scenario did not have a triad priority alert in any of the load periods, so the probability of a demand charge was uniformly small for all load periods in the day. As a consequence, this reduction in the demand charge had no discernable predicted impact on the pattern of electricity consumption. The second scenario assumed that a triad priority alert was in fact issued for load period 24, so using the estimated probability function given in Patrick and Wolak (1997), the probability of a demand charge in period 24, went from close to zero to approximately 0.12. As a result of issuing this triad priority alert, there is a significant demand reduction predicted for load period 24. There is also predicted to be a slight reduction in electricity demand in load periods 31 to 36.

These examples illustrate some of the sorts of predicted price responses that can be computed using these parameter estimates. Given this information on price responses and the standard errors around these responses, the electricity supplier can then estimate the effect of alternative prices on customer load, customer benefits, and supplier revenues as well as compute the associated uncertainty in these estimates.

We next provide an example of how our demand system estimates can be used to formulate demand-side bids by electricity suppliers serving customers on real-time prices (or the PPC). If suppliers purchasing from the E&W market are able to accurately predict the response of demand to within-day price changes for their customers on the PPC, this information can be used to formulate a demand-side bid function for each supplier.[xvii] If a supplier is able to entice more customers to face prices for electricity which reflect the current PSP from the E&W market for that half-hour, given accurate estimates of the price-responses of these customers, the supplier can then formulate an aggregate demand-side bid function which has a relatively larger price response.

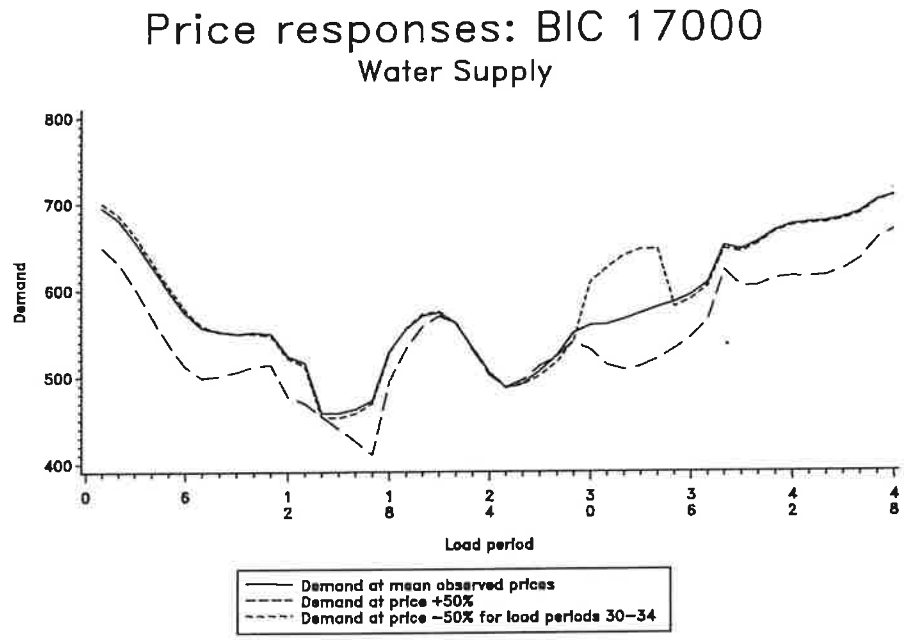

Figure 9. Demand Response to Energy Price Changes.

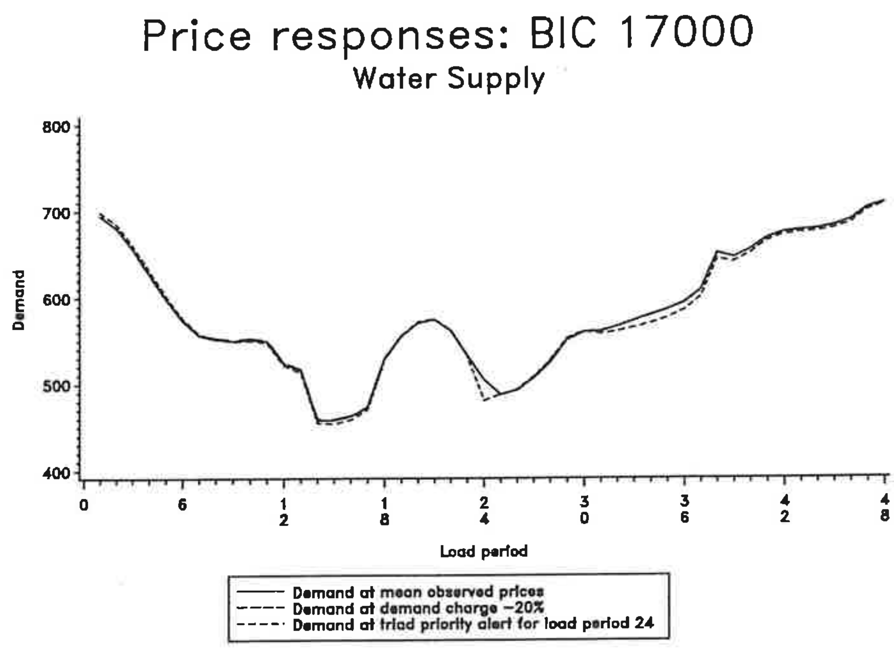

Figure 10. Demand Response to Demand Charge Changes.

Figure 11 illustrates the effects of demand-side bidding in the E&W SMP determination process. TSL is the perfectly price inelastic forecasted demand used along with generator bids to supply electricity to determine the half-hour's SMP (labeled P_{SMP}). Demand-side bidding effectively introduces elasticity into the demand-side in the price determination process, leading to the half-hour's SMP of P_{DB}, which is lower than the SMP set by an inelastic demand. Recall that this analysis assumes no change in bidding behavior by generators in response to demand-side bidding, which seems unlikely given that under demand-side bidding, generators face the likelihood not being called on to generate as a result of bidding too high of a price into the pool and should therefore bid more aggressively, resulting in an even lower SMP. As emphasized by Wolak and Patrick (1997), the current operation of the E&W market illustrates the sort of price volatility that can occur if the demand setting the market price is very price inelastic and only a small fraction of the total electricity consumed in any half-hour is sold to final customers at prices that vary with the half-hourly PSP. Consequently, accurate measurement of the within-day price response of customers is an important necessary ingredient for any electricity retailer to aggressively demand-side bid, and thereby build a significant price-responses into the market price-setting process. Our demand estimates provide the necessary information to effectively demand-side bid.

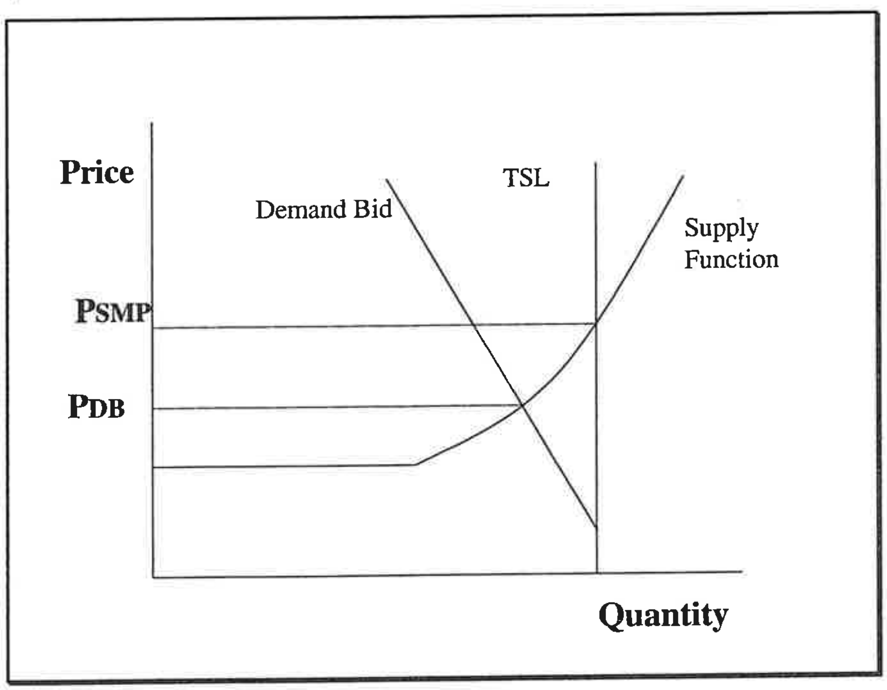

Figure 11. The Effect of Demand-Side Bidding on the Market Clearing Spot Price.

We now consider the impact of changing a single half-hourly price within the day on the demand in that load period and all other load periods during the day. We assume that the base period pattern of prices is the sample mean of the vector of load period-level expected prices given in Table 1. We assume that the supplier has ten customers from BIC 17000 (which is the approximate number of water supply customers on the supplier's PPC in 1994-95). We assume that the price in load period 27, P_{27d}, increases from its sample mean of 35 £/MWh to 100 £/MWh, a large but not unheard of change in prices. The own-price response is a reduction in demand in load period 27 of 41.13 kWh per customer, or a total of 411.3 KWh for ten customers. Computing the demand change for each load period in the day except load period 27 and multiplying by 10 yields the demand schedule plotted in Figure 12, which indicates where portions of the 411.3 kWh that are predicted to no longer be consumed in load period 27 are predicted to be consumed during the other load periods during the day.

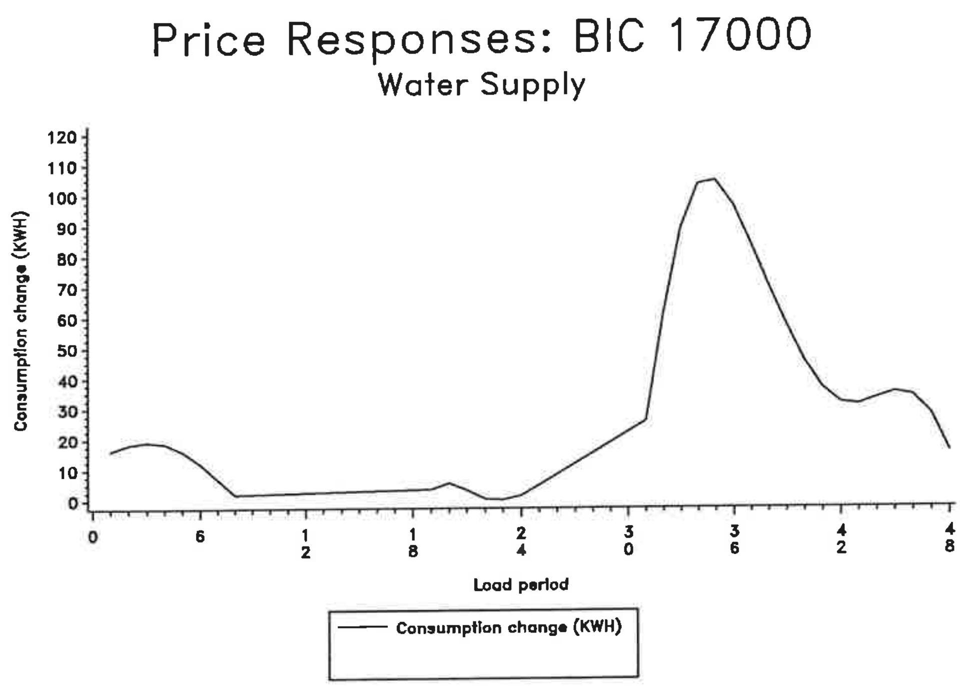

Figure 12. Demand Response to a Price Increase in Load Period 27.

Proceeding in this manner for a variety of prospective prices, given the mix of customers on the PPC, the supplier can determine the magnitudes of price responses it can expect from various changes in the expected prices aggregated over all of its customers. Coupled with information on the standard errors of the these predicted price responses, the supplier can then formulate demand-side bid functions which account for the aggregate estimated price response of all of the supplier's PPC customers and the uncertainty associated with these responses.

6. DIRECTIONS FOR FUTURE RESEARCH

The demand models discussed in this chapter are essential inputs into the successful design of market-based strategies for enhancing customer and utility benefits in increasingly competitive electricity markets. These models develop customer-level demand relationships which are necessary in the design of pricing options to attract and maintain customers in a market with competing suppliers, while insuring that the costs of each customer's consumption are covered. The financial viability of a wide variety of pricing policies in a competitive environment can be assessed, which will ideally account for the potential competitive responses of other suppliers, the specific characteristics of the population of customers the supplier can potentially serve, and the stock of generation, transmission, and distribution capacities available to the supplier and its competitors. In addition, the demand models' uses include forecasting customer-level electricity loads, revenues from electricity supply, and customer benefits under alternative rate structures, including various energy and demand charge combinations; estimate the own-price and cross-price elasticities, which can be used in rate simulation and optimization programs; and to develop demand-side bids.

NOTES

[i] As of August 1, 1999, twenty-four states have restructured electricity industries to encourage competition and provide consumer choice (Energy Information Administration).

[ii] See, for example, Thomas A. Stewart ("When Change is Total, Exciting and Scary" *Fortune*, March 3:169-170, 1997), which presents an overview of some of these issues and the views of Duke Power's CEO, William H. Grigg.

[iii] The costs of serving a customer are heavily dependent on the customer's consumption path (as is indicated by the pool price paths presented below). Since the customers' prior consumption path may be unobservable (depending on metering capabilities and access to information on the consumer), it is easy to envisage situations where the customer's consumption could be subsidized by a pricing policy offered.

[iv] These are customers with at least 100 kW demands.

[v] Wolak and Patrick (1996a, 1997) provide further on the mechanics of the price determination process.

[vi] To insure that "fixed" costs are not congregated in a few periods, thereby driving up the relative prices in these periods, there is an upper bound on the number of Table B periods each day. See Wolak and Patrick (1997) for these details as well as the determination of Table A versus Table B half-hours.

[vii] Fiscal years in the E&W market run from April 1 through March 31 of the next year, e.g., the 1995 fiscal year runs from April 1, 1995 through March 31, 1996.

[viii] MEB was both a supply and distribution company over the time period represented by our data. Supply and distribution companies have since been separated, see Patrick and Wolak (1999) for details.

[ix] These three half-hours are subject to the constraint that they are each separated by at least ten days. Triad charges can only be known in March of each fiscal year, after actual electricity consumption has occurred.

[x] Patrick and Wolak (1997) analyzed five of these industries: water supply (BIC 17000), copper, brass, and other copper alloys manufacturing (22460), ceramics goods manufacturing (24890), hand tools and finished metal goods (31600), and steel tubes manufacturing (22200).

[xi] Patrick and Wolak (1997) provide more detail on the fax, including a sample fax.

[xii] Patrick and Wolak (1997) report all triad advance warnings, priority alerts, and actual triad periods for our sample.

[xiii] See Patrick and Wolak (1997, 1999) for a description of the specific charges.

[xiv] The E&W CFD market has been dominated by generating firms. CFDs generally cover the PPP but not UPLIFT, triad, or other charges.

[xv] Patrick and Wolak (1997) estimate the expected demand charge.

[xvi] 3-dimensional plots of the sample mean of the cross-price elasticities, indicating the type of within-day demand substitution patterns that exist for some PPC customers, can be found in Wolak and Patrick (1997, 1999).

[xvii] Inaccurate demand-side bidding would lead to a higher half-hourly UPLIFT component of the PPC. UPLIFT, the component of the PSP that is determined after demand is realized, is generally not covered by the CFDs contracts used to hedge wholesale electricity price volatility.

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