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UTILITY SPOT PRICING STUDY: WISCONSIN

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ABSTRACT

Spot pricing covers a range of electric utility pricing structures which relate the marginal costs of electric generation to the prices seen by utility customers. At the shortest time frames prices change every five minutes--the same time frame as used in utility dispatch--longer time frames might include 24-hour updating in which prices are set one day in advance but vary hourly as a function of projected system operating costs. The critical concept is that customers see and respond to marginal rather than average costs. In addition the concept of spot pricing includes a "quality of supply" component by which prices are increased at times in which the system is approaching maximum capacity, thus providing a pricing mechanism to replace or augment rationing.

This research project evaluated the potential for spot pricing of industrial customers from the perspective both of the utility and its customers. A prototype Wisconsin (based on the WFPCO system) and its industrial customers was evaluated assuming 1980 demand level and tariff structures. The utility system was simplified to include limited interconnection and exchange of power with surrounding utilities. The analysis was carried out using an hourly simulation model, ENPRO, to evaluate the marginal operating cost for any hour. The industrial energy demand was adjusted to reflect the price (relative to the present time-of-use pricing system). The simulation was then rerun to calculate the change in revenues (and customer bill) and the amount of consumer surplus generated.

A second analysis assumed a 5 percent increase in demand with no

increase in capacity. Each analysis was carried out for an assumed low and high industrial response to price changes.

In an effort to generalize beyond the Wisconsin data and to evaluate the likely implications of a flexible pricing scheme relative to a utility system with a greater level of oil generation, particularly on the margin, the system capacity of the study utility was altered by substitution of a limited number of coal plants by identical but with higher-fuel cost oil-fired plants. The analyses for the modified utility structure are parallel to those for the standard utility structure discussed above.

The results of the analysis showed that the flexible pricing system produced both utility and customer savings. At lower capacity utilization the utility recovered less revenue than it did under the present time-of-use rates. While at higher utilization it recovered more. Under all scenarios tested, consumer surplus benefits were five to ten times greater than were simple fuel savings for the utility. While these results must be evaluated in additional testing of specific customer response patterns, it is significant to note that the ability of the customer to choose his pattern more flexibly holds a significant potential for customers to achieve greater surplus--even if their bill may in fact increase. These results are discussed in detail in the report as are a number of customer bill impact considerations and the issues associated with revenue reconciliation.

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CHAPTER 1

INTRODUCTION

Electricity rate structures have been the subject of extensive theoretical as well as experimental investigation and in some cases widespread application. A major EPRI study recently completed provides extensive background.* The various proposed or implemented rate structures have sought improvements in a wide range of social objectives including not only cost of electricity generation but also reliability of supply, utility profits, customer benefits, and even income distribution. The nature of electricity demand and generation characterized by both cyclic and random variations in load and available generation capacity has affected the design of rate structures. Another means of achieving improvements in the above objectives which has recently received increased attention has been direct load control.

This report examines a concept of electricity pricing referred to as spot pricing.** Spot pricing has been shown in theory to encompass and achieve more fully the objectives of most rate structures and load control and management techniques proposed in the past.

Spot pricing is an approach to electric power systems pricing which does away with concepts such as block rates, demand charges, backup charges and capacity credits. Instead, an energy marketplace for electricity is established which determines the spot price of electricity by the supply and demand conditions, that is, the marginal value of

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*EPRI, Electric Utility Rate Design Study, Palo Alto, 1979.

**In the literature this has also been referred to as responsive pricing, real time pricing and flexible pricing.

consumption and generation of electricity at each instant. Optimal spot pricing is desirable because it improves the efficiency of the electric power system. It can significantly improve the well-being of both generators and customers through lower costs, fewer blackouts and brownouts, easier integration of customer-owned generation and other advantages. It can give higher profits for both the utility and its customers.

The first chapter of this report sets forth the theoretical issues associated with flexible or spot pricing. Chapter Two provides the derivation of optimal spot prices and their effect on generation, transmission and distribution constraints; transaction costs; and intertemporal demand interdependencies. Optimal predetermined prices for small or unresponsive consumers (who would not justify their spot pricing because the associated transactions and communications costs overshadow potential benefits) are also derived. Pricing period lengths and optimal assignment of customers to a range of rate structures from real time spot pricing to predetermined prices is also considered. Utility and consumer investment rules under spot pricing are developed and optimal buy-back rates for non-utility-owned generation are addressed. Finally, revenue reconciliation issues are discussed and a comparison of spot pricing to the related pricing literature is undertaken.

Chapter Three presents the data, the algorithm and the general analytic results. Chapter Four presents the results of the case study focusing on the potential benefits of bringing large WEPCO industrial consumers under spot pricing. Revenue reconciliation issues and the distrbution of benefits are addressed. The main thrust of the case study, however, is directed at providing estimates of potential fuel savings, consumer surplus gains, reduction of reserve capacity requirements and trends of a desired reoptimization in generating capacity mix.

Chapter Five examines the potential impact of spot pricing on individual customer bills to identify potential cross-subsidies among customers. The characteristics of individual large customer demand profiles are also presented.

CHAPTER 2

THEORY

2.1. Introduction

Flexible or spot prices are prices which fluctuate over time in response to the current condition of the utility system. Spot pricing combines the best features of direct load control/direct central dispatching with those of time-of-use pricing. This gives real time feedback and control with customer independence and no need for central knowledge of customer requirements or status. Spot pricing is an approach to electric power systems pricing which does away with concepts such as block rate, demand charges, back-up charges, capacity credits, and so on. Instead, an energy marketplace for electric power is established. The spot price for buying and selling electric energy is determined by the supply and demand conditions at that instant.

Optimal spot pricing is desirable because it improves the efficiency of the electric power system. It can significantly improve the well being of the utility system (generators and customers) through lower costs, fewer blackouts and brownouts, easier integration of customer owned generation, and other advantages. It can give higher profits for both the utility and its customers. Examples of the impacts of optimal spot pricing include:

- o Reduction of oil consumed in generation by raising prices explicitly whenever oil is being used.
- o Removal or reduction of the need for rotating blackouts to handle emergency generation shortage situations, by using prices to give an automatic socially efficient rationing system.
- o Enhancement of and integration of wind, solar, and customer-owned

cogeneration into the grid by providing an energy marketplace which values energy at its "true" value. Variable charges, back-up charges, and capacity credits are not needed.

Optimal spot prices have the disadvantage of requiring rapid communications between the customer and the utility and of requiring extensive metering and control equipment. This report summarizes a number of pricing options which achieve nearly all of the advantages of the shorter time spot pricing schemes while lowering the communication, metering and control costs of both the customer and the utility.

The purpose of this chapter is to set forth the theoretical issues associated with spot pricing.* The chapter is detailed in its approach to spot pricing as it takes the perspective of social welfare economics. For the reader wishing to skip over the theoretical development it is suggested that they read only the major points listed at the end of Sections 2.2 through 2.5 and the graphical presentation in Section 2.2B. The chapter is organized as follows: The derivation of optimal (instantaneous) spot prices is provided in Section 2.2, together with consideration of the effects of generation, transmission and distribution constraints; transaction costs; and time dependent customer demands. The derivation of optimal predetermined prices is set forth in Section 2.3. In Section 2.3 pricing period lengths, customer class assignment and optimal rationing of customers on predetermined rates are also considered. Utility and consumer investment rules under flexible or spot pricing are developed in Section 2.4. Optimal buy-back rates for

*This chapter draws heavily upon Bohn [1982], Bohn, Caramanis, Schweppe [1981], Caramanis, Bohn Schweppe [1982], Caramanis [1982] and Kepner [1982].

non-utility-owned generation is addressed in Section 2.5. Revenue reconciliation issues are raised in Section 2.6. Section 2.7 contains a discussion of the related pricing literature.

2.2. Deriving Optimal Spot Prices

2.2.A) Assumptions and Pricing Rules

A utility system is composed of centrally owned and controlled generating plants, independent customers, and the transmission and distribution (T and D) system which links them. The utility must choose:

- o the output of each of its generating units;
- o the price to each customer; and
- o investments in future generating plants and the T and D system.

The utility must make these decisions to meet the following constraints:

- o Total generation must equal line losses plus total demand at each moment;
- o No generating unit can have an output higher than its available capacity;
- o Demands and unit availability vary stochastically; and
- o Transmission and distribution capabilities cannot be exceeded.

Spot pricing theory provides rules for both optimal short-run decisions and optimal long-run action (investments). Here we concentrate on the "operational problems," assuming that investments in power plants, transmission and distribution networks (T and D), and customer equipment are already in place. These investments can be chosen based on anticipated spot prices (see Section 2.4).

The derivation of spot pricing proceeds as follows. Different paths of electricity use and investment over time lead to different social welfare levels. For electric power production and consumption social welfare function is defined as:

Welfare =		Value of Electricity Usage	-	Variable and Fuel Costs	
					(1)
	-	Cost of Rationing	-	Cost of Equipment	

The first two terms (value of usage and cost of fuel) are random variables, as they depend on random plant and network outages, weather, customer desires, etc. The cost of rationing term would always be zero if all customers were on optimal spot pricing. The general theory covers the case of two coexisting groups of customers; one under spot pricing and the other on predetermined prices. In emergencies, the predetermined price customers may have to be rationed (see Section 2.3).

If we take the perspective of a global controller, the decision variables are the generation level of each generating unit, and the usage level of each customer device, at each moment. The objective is to maximize social welfare. The calculus of variations gives the conditions on the decision variables which must be satisfied. Two explicit sets of constraints are imposed on the optimization:

Energy Balance Constraint:
Total Generation = Total Consumption + Losses (2)

Network Constraints:
Voltage magnitude and line flow constraints (3)

These constraints explicitly involve the random variables of weather and outages, and the decision variables of generation and demand at each point in the network.

The constrained optimization conditions are satisfied by optimal spot pricing in conjunction with standard economy dispatching. If proper spot prices are set each customer will reach the socially optimal usage level as a result of its own efforts to maximize profits.

The resulting spot prices are explicit functions of all random variables, and therefore change over time as these random variables change.* The general formulas can be interpreted as:

$$\begin{array}{c}\text{Optimum}\\ \text{Spot}\\ \text{Price}\end{array} = \begin{array}{c}\text{Marginal}\\ \text{Fuel Cost}\end{array} + \begin{array}{c}\text{Energy}\\ \text{Balance}\\ \text{Quality}\\ \text{of Supply}\\ \text{Premium}\end{array} + \begin{array}{c}\text{T and D}\\ \text{Network}\\ \text{Quality}\\ \text{of Supply}\\ \text{Premium}\end{array} \qquad (4)$$

There are separate spot prices for real and reactive energy.

The marginal fuel cost component of equation (4) is the incremental fuel cost of the most expensive unit currently loaded in the system (generators should be dispatched in optimal loading order, as is the present practice) appropriately corrected for transmission and distribution losses. It is close to the conventional "system lambda," with an additional location specific correction for losses. Since losses vary by location, each customer sees a slightly different price.

The energy balance quality of supply premium of equation (4) is zero at all times when there is surplus generation or tie-line capacity. If all generators are in use and no additional energy is available over tie lines, then the premium is added to the price to reduce demand or increase customer generation until the energy balance constraint of

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*Note that all utility rates can be expressed as the expected value over some time cycle period of the optimal spot price. A marginal time of use rate is the expected value of the optimal spot price for fixed time blocks (i.e. 9 a.m. to 5 p.m.) for the price update cycle (i.e. one month or a season).

equation (2) is met. The premium is then the difference between the incremental value of electrical usage for the incremental customer, and the marginal fuel cost. It varies by customer to the extent that transmission and distribution losses vary by customer.

The quality of supply premium associated with the T and D network arises because of the network constraints of equation (3). When neither the line flow constraints nor the voltage magnitude constraints are active, then the premium is zero. When the constraints are active, the premium is an extra pricing signal which is sent to customers until they readjust their usage and generation (if they have it) patterns to remove the line overload or voltage imbalance. This component is heavily variable between customers, as the physical location of the customer has a major impact on the network constraints. Notice that the network quality of supply premium can be either positive or negative, depending on what type of readjustments in generation/usage patterns are required. In some circumstances it is conceivable that a customer should be encouraged to increase its usage.

When loss coefficients are incorporated, spot prices for reactive power are developed analogous to the prices for real power. In theory, there should be a different price for real and reactive energy at each point in the T and D network, implying that each customer should continuously see two prices. In practice, the price of reactive energy will not vary significantly, nor will a customer's power factor change greatly over time. Therefore spot pricing of reactive energy could be approximated (for all but the largest customers) by assuming a constant power factor for all customers in a class, where class is determined by voltage level of service and general location in the T and D network.

The customer would then see a single price for real + reactive energy.

2.2.B) Graphical Representation

It is instructive to formulate the spot pricing problem graphically. Figure 2.1 shows the instataneous marginal variable generating cost function for a given utility system.

Figure 2.1

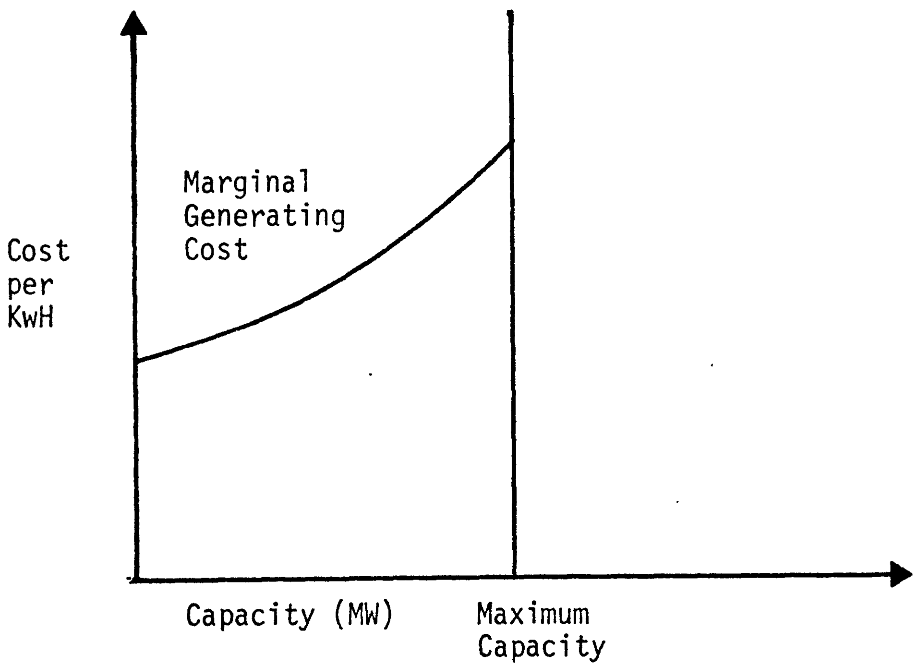


Figure 2.2 shows the analogous diagram for instantaneous customer demand.

Figure 2.2

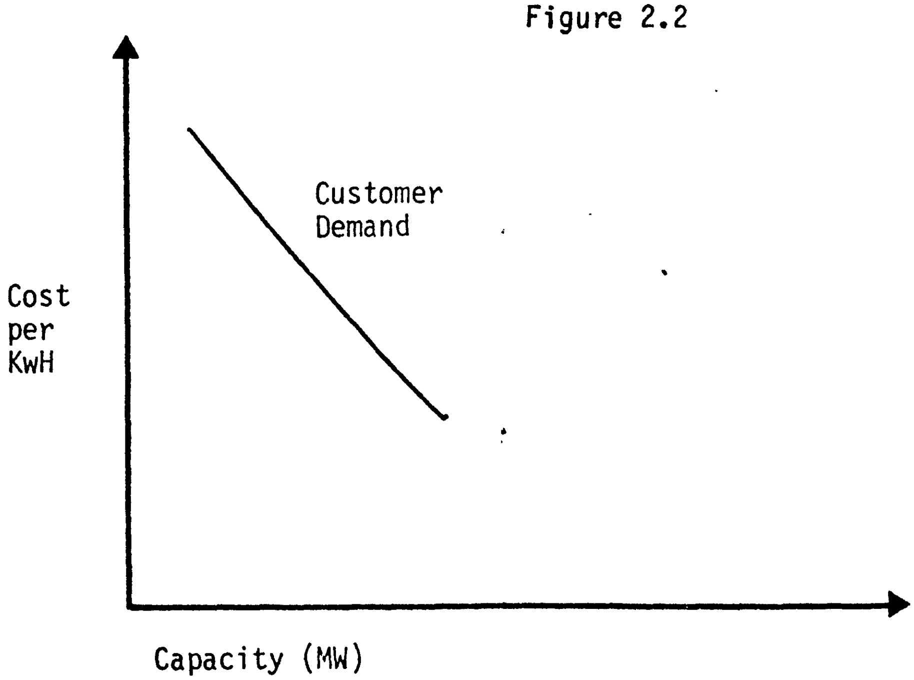


Figure 2.3 shows the optimal price level (p*) when the instantaneous quantity demanded at the optimal price does not exceed the maximum generating (or T and D) capacity.

Figure 2.3

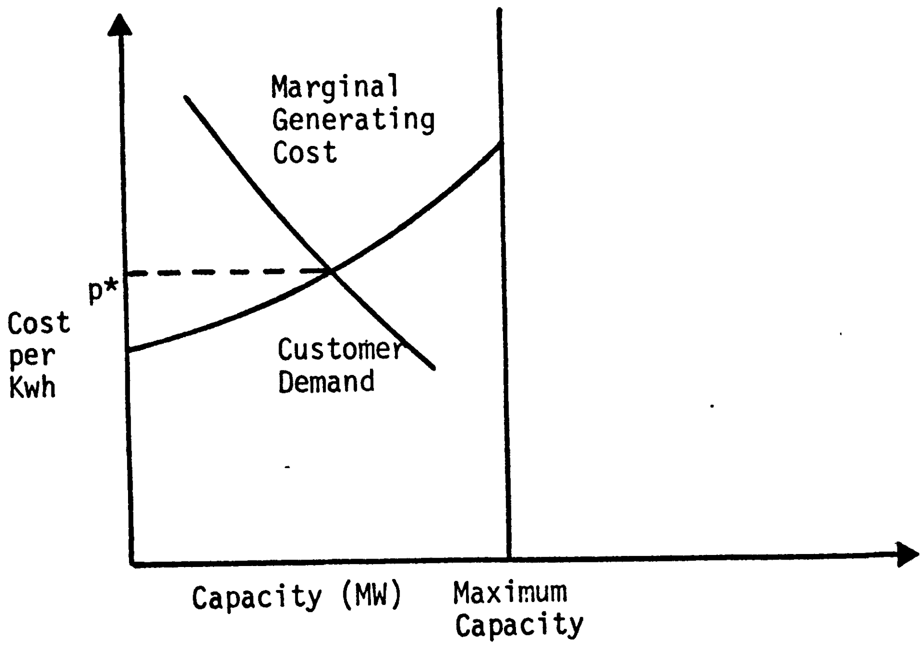
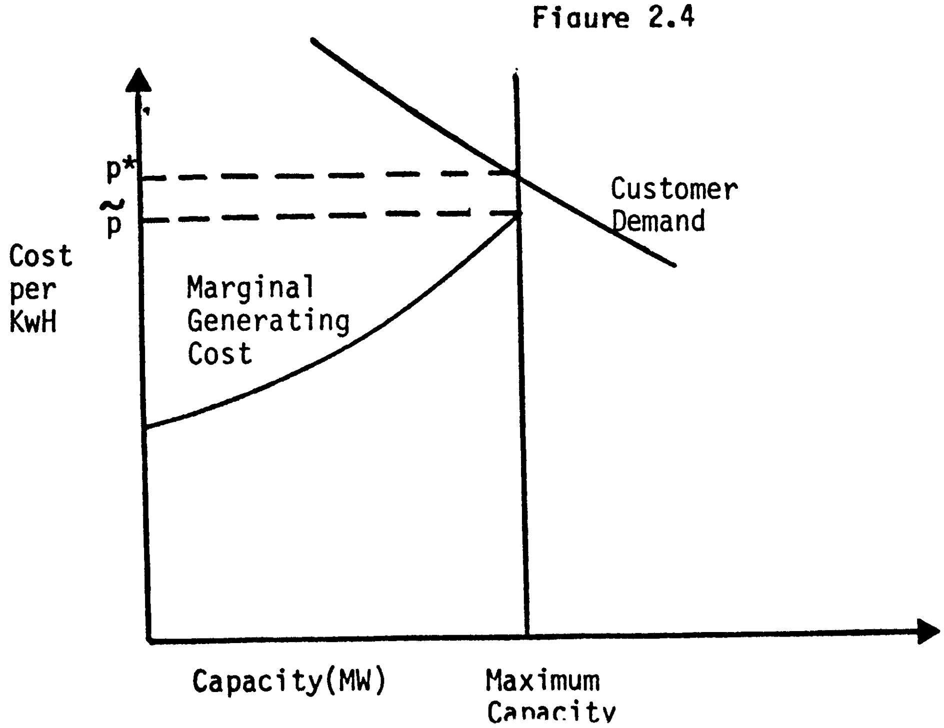


Figure 2.4 shows the optimal spot price (p*) when available capacity is fully used. Note that the premium ($p^* - \tilde{p}$), or the difference between the optimal spot price and the marginal generating cost of the last unit produced, is the quality of supply premium.

Figure 2.4



2.2.C) Time Interdependency

The basic optimal spot pricing results are derived without consideration of the time interdependency of demand. These interdependencies (such as storage or production rescheduling) can, however, easily be incorporated into the basic spot pricing framework. Time is introduced by recognizing that past and future consumption levels are relevant to customer decisions concerning storage, rescheduling, and other intertemporal processes of concern. Incorporating time demand interdependencies leads to analogous spot pricing results. The optimal spot price is the sum of a quality of supply component and marginal generating costs. Marginal generating cost, however, is calculated as the expected impact of incremental generation now on current variable generating costs and variable generating costs in the next few periods.

2.2.D) Transaction Costs

If the demand for and the supply of electricity could equilibrate instantly under a spot pricing system, and if the "transaction costs" of spot pricing were zero, all customers should be placed on a spot pricing schedule. Not all customers, however, could respond instantaneously to a spot price signal. And neither are the transaction costs--which include the cost of utility and customer premise's equipment, price calculation, and signal transmission--likely to be zero. Further, instantaneously varying price signals may be administratively impractical. Consequently pricing periods of varying lengths may be more appropriate. It is to the question of setting the predetermined prices for the various pricing periods which we turn in the next section.

2.3. Optimal Predetermined Prices

2.3.A) Assumptions and Pricing Rules

The full spot prices derived and discussed above are "optimal" only with no transactions costs. When transactions costs are considered, it generally will be preferable to aggregate prices over time cycles (from minutes to months), over classes of customers (residential...industrial) and/or over service regions (the area of a specific substation). Different rates, with their own amount of aggregation, may be optimal for different participants. Rates here are "optimal," for a given level of aggregation, under the assumptions that:

- o Only "first best" welfare issues are considered.
- o If multiple rates, and hence multiple prices at one instant, are used, no arbitrage selling is permitted between participants on different rates.

In theory each participant (customer or generator) should have its own spot price, reflecting its unique impacts on system losses, line flows, and line voltages. In practice such a pricing system will be overly sophisticated for most customers. Therefore simpler versions of spot pricing are proposed, to be adapted to individual utilities and customers.

Under realistic implementations of spot pricing, not all participants will receive real-time updates of the spot price. Some customers will get price updates only daily, monthly, or even yearly. This will hold down metering and communications costs. In this case the price at time t cannot reflect the actual values of random variables at time t, but instead must be set based on the expected values of those random variables, conditional on information available at the time these prices are set. We will call these "predetermined" prices, recognizing that they are not truly predetermined forever, but only until the next update. In general, the optimal predetermined price for time t is given by:

$$\text{Optimal Predetermined Price} = \text{Expected Value of Optimal Spot Price} + \text{Covariance Term} \qquad (5)$$

The covariance term depends on the customer's demand and its correlation to the spot price. It is positive for most customers.

2.3.B) Pricing Periods

Most of the practical considerations involved in setting "spot" prices can be understood for the special case of equation (5) in which there are no quality of supply components, no losses, and only real energy is priced. This is the easiest version of spot pricing to implement.

The theory developed in Section 2.2 does not explicitly consider the cost of communicating the spot price to customers and metering their use. If these costs were zero then all customers should receive the instantaneous spot price, in continuous time. A more realistic approach is to implement spot pricing using one of the following new or restated types of spot price based rates:

5 MINUTE SPOT PRICE. The shortest time varying rate discussed. The pricing cycle is five minutes reflecting the expected cost of generation plus transaction costs and T and D for each five minutes projected five minutes ahead. The information utilized is analogous to the time frame used by the system dispatcher and incorporates system lambda or its equivalent as the marginal operating cost.

1 HOUR SPOT PRICE. Equivalent ot the 5 minute spot price with recalculation on a 1 hour cycle. This study of Wisconsin examined the benefits of a 1 hour spot price structure.

Calculating the proper level of each price can be done using existing mathematical methods and even computer programs, since the different prices are analogous to existing problems in generation dispatch. Five-minute spot pricing is analogous to economic dispatch, and the price is responsive to random weather variations, unexpected plant outages, and T+D failures. Twenty-four hour update spot pricing is analogous to unit commitment, and reflects known outages and the daily weather forecast. Time-of-use predetermined price is analogous to maintenance scheduling and nuclear unit refueling, and can reflect only the normal pattern of demand and precipitation (on a hydro system).

The only major new development needed to calculate properly each of these prices in real time is the development of a short-term demand response model. Such a model can be developed from experience as spot pricing is gradually implemented by a utility. When we ignore losses and the T+D system, all custmers on one pricing system see the same price. This simplifies calculations.

2.3.C) Customer Assignment

Different customers should be assigned to different price systems depending on their size and ability to respond to more sophisticated prices. Metering and communication costs depend mainly on the price system, not on the customer. The cost of even 5-minute spot pricing will be trivial for large industrial or commercial customers. Small residential customers whose demands are too small to justify the cost of a recording meter should be on time-of-use predetermined pricing. Other customers should probably be on 24-hour update spot pricing. Of course, still other pricing systems are feasible and should be used if the net benefits compare favorably to those under the three systems discussed above. Customers should be allowed to self-select their pricing system provided that they pay all incremental metering and communications costs.

Several points should be noted about how customers should be assigned to different rates.

- The social welfare maximizing rate for each customer depends on the customer's size and how it would behave under various rates, and on the transactions costs of different rates.
- Any rate other than full spot pricing can create a subsidy, that is, a wedge between private and social costs. This subsidy can be positive or negative and is customer specific. It must be made up by the utility or other customers. Therefore which rate a customer is on affects profit distribution as well as total social welfare.
- Therefore, customers will not always voluntarily choose the socially prefered rate for themselves.
- The utility cannot adjust rates so that "on average" customers will self assign to the socially prefered rate or close to it. The problem is analagous to what happens in competitive insurance markets with adverse selection: those receiving large positive subsidies under a rate drive everyone else off that rate.
- Mandatory assignment of customers to rates, which is standard practise for some public utilities, cannot be done optimally either. Such assignment would require unobservable customer specific information.

- In practice a combination of mandatory and voluntary assignment will probably give "reasonably good" results, and is the best that can be done.

Which rate a customer or independent generator is assigned to will affect three costs:

- Communications and other transactions costs.
- The value of electricity used by the customer in response to prices under the rate.
- The customer's value added as a result of its electricity use.

Both the social and private assignment criteria are: "assign the customer to the rate which maximizes its expected value added, minus transactions costs and the expected value of electricity used." This sum is the net social or private welfare gain under a rate. The difference between social and private criteria is that a profit maximizing customer will value electricity at its price under the rate in question, whereas the social value of the electricity used is always the full spot price at the moment of use. Under any rate except full spot pricing there will be a divergence between social and private value; therefore the customer will compare rates differently than will a social welfare maximizer.

Several implications can be drawn for comparing two rates, one of which may be full spot prices:

- If a customer's behavior will be the same on one rate as on the other, then the rate with the lower transactions costs is socially preferable for that customer.
- The gross social welfare change will depend on the customer's size and responsiveness to spot prices. It will therefore be socially optimal to use more sophisticated pricing methods for

customers which are larger or more responsive (in percentage of demand) to prices.

- If two rates have the same transactions costs, the one which is closer to full spot prices should be used.
- Whether a customer self-selects the socially optimal rate depends on its subsidy, which is a weighted average of the difference between the spot price and the predetermined price. The larger the absolute value of the subsidy, the less likely the customer is to select the socially desired rate. The subsidy may be positive or negative.
- Customers with weather sensitive loads which are correlated with spot price will tend to have larger subsidies under any predetermined price than do other customers.
- Customers with weekday only demands (KwH) will be susbsidized by flat non time-of-day rates.

In order to decide what rate a customer should be on, the utility needs to know something about how the customer would behave under alternate rates, and what the value of that change in behavior is to the customer. These will depend on the customer's options to substitute electricity for electricity at a different time and for other inputs to production. No central utility can know each customer's opportunity set. Even for classes of customers with many members, experimental methods will mainly give an indication of the mean and variance of changes in gross social welfare under different rates, which is not sufficient.

A reasonable approach to the assignment problem is therefore to use a mixture of mandatory and voluntary assignment. Participants can be divided into classes based on more-or-less exogenous characteristics, as is done today. Ownership of particular types of capital, such as electrical or thermal storage equipment, would be an important critierion for membership in some groups. Within each class participants might be offered a choice from among two or more rates, with the range of choices overlapping among different classes. It is important to remember that the optimal range of rates and "optimal" assignment rule will be utility-specific.

It is not possible _a prior_ to state the precise implications of these points for individual of today's customer classes. Several general conclusions can, however, be drawn. The first is that larger customers with reschedulable loads will be those that will benefit the greatest from shorter time period spot price rates. Because of their size the benefits will be sufficient to warrant investment in capital and control system to take advantage of the rates. Because their loads may be rescheduled they will have maximum flexibility in shifting in response to price. Smaller customers will be able to take advantage of different of the spot price related rates including those that are now refered to as load control in which the utility is providing the service of 'shedding' of specific customer functions. The benefit to be gained from such systems will determine both the customer participants and the level of automation in control that is cost justified. Additional analysis and research is required to understand the ability of different types of customers to respond to various spot price systems based on different price update cycles.

How many rates to offer depends on the relative transactions costs and social welfare benefits of additional rates. Each new rate carries with it some transactions costs which are independent of the number of participants on that rate. If all these costs were zero, it would be optimal to have an infinite spectrum of rates. Instead, the additional transactions costs must be weighed against the improvement in net social surplus for participants asigned to this rate instead of the previously available rates. An additional rate will be more desirable the better the method for assigning participants to it.

2.3.D) Rationing

What if customer response to a rise in the spot orice is not large enough to avoid a problem entirely This may not happen, for example, on systems where only a few customers are on 5-minute spot pricing. In this situation, the necessary response will be identical to present practice, namely rotating blackouts.

In practice, rationing will be appropriate mainly when the curtailment premium reaches levels close to the average disruption cost of rationing a group of non spot customers. Rationing these customers is then socially preferable to making customers on full spot pricing voluntarily curtail further in reponse to still higher spot prices.

Thus under optimal utility behavior:

- o The possibility of rationing effectively puts an upper bound on spot prices, equal to the marginal disruption losses caused by rationing.
- o The more participants are on spot pricing, the less often rationing will be needed for other participants, since the more likely that demand can be held down at spot prices below the disruption cost of rationing.

o The probability that a customer will be rationed is an increasing function of the difference between spot and predetermined prices. When multiple rate classes may exist with different rules for updating their prices, all else equal, participants on infrequently updated prices will be rationed most often, since their prices will have the largest forecast errors.

One special case corresponds to present utility operation. If all participants are on the same non-spot prices then the curtailment premium jumps from zero to the social loss due to rotating blackouts or whatever rationing method the utility uses.

As a practical matter, those customers on 5-minute pricing are effectively never subject to involuntary blackout--instead they voluntarily back off as the spot price is raised. When the spot price reaches a certain level if demand is still too high, rotating blackouts should be applied to customers on time-of-use pricing and 24-hour update pricing. Customers on 24-hour update pricing will never be subjected to rotating blackouts for more than 24 hours. Instead, their price will be raised to induce voluntary cutbacks.

There are two practical problems with the rationing rate. Although there is a mathematical expression for the critical level of spot price at which the price should stop rising and rationing be used, calculating this price will require a combination of survey information and political considerations. The interests of customers on different prices will be opposed.

The second problem is that customers on 5-minute pricing may be served by the same portion of the distribution system as other customers. It would then be difficult to apply rotating blackouts to all time-of-use customers without cutting off the 5-minute customer.

2.4. Investment Behavior

2.4.A) Utility Investment Under Spot Pricing

(1) Generation

Optimal spot prices determine the revenues accruing to generating units. Whenever the spot price is equal to or exceeds a generating unit's variable cost, it is profitable for that unit to generate. The investment conditions discussed below imply that social welfare is maximized if enough capacity of each generation type is installed to render the present value of the expected net income stream associated with incremental investment equal to its cost. If the above present value exceeds incremental investment costs for a particular generation type, it is optimal to install more capacity of that type. On the other hand, costs exceeding revenues is an indication of overinvestment.

(2) Transmission and Distribution

The necessary conditions for T+D optimal investment are:

Cost of Incremental Investment in T+D Capital Stock	=	Transportation Losses Related Term	+	Voltage Magnitude and Line Flow Related Term	+	Shifting of Network Constraint Limits Term	(6)

Eq. (6) may be interpreted as follows. The first term represents the impact of incremental investment on losses evaluated at the spot price marginal operating cost and energy balance premium components. The second term represents the impact of incremental investment on easing binding line flow and voltage levels evaluated at the T+D constraint premium. Finally, the third term represents the impact on constraint limits.

Customers contribute to T+D revenues according to their location, electricity usage characteristics and usage-related benefits. Hence, the impact of T+D investments (lines, transformers, etc.) will in turn benefit customers in proportion to their contribution. Of course, in the case of new area development, anticipated future customer usage will provide for the investment's payback. It should be finally noted that because of the location specific contribution of electricity usage to T+D revenues, optimal spot pricing establishes a socially efficient "wheeling" charge.

2.4.B) Customer Investment Under Spot Pricing

There is a variety of investments which customers can make to reduce the cost of electricity under spot pricing. For customers designing new production facilities, the availability of spot prices may be a design parameter for capacity decision in the production process. In existing facilities the availablility of spot rates may encourage rescheduling of energy intensive processes or the investment storage of specific capacity. For others there may be equipment which can be retrofit within an existing factory.

Specifically, possible customer investments include:

1. Building a cogeneration system instead of a simple boiler. The electricity demand of customers with cogeneration will depend heavily on the steam demand; but when the spot price is high enough cogenerators will be willing to maximize electricity production even if this requires wasting some steam. There are incentives for installing cogeneration even with constant

predetermined prices, but the value of each kilowatt of cogeneration capacity will be higher under spot pricing than under predetermined prices with the same mean.

2. Thermal storage equipment, such as chilled water tanks for air conditioning or refrigeration. This effectively allows storage of electricity in the form of thermal energy. This storage can be "filled up" when price is low, and "discharged" when it is high.

3. More efficient motors, better insulation, and other conventional methods for reducing total demand.

4. Increased pump and pipe capacity for agricultural irrigation and other fluid pumping applications. They would be used to conduct non critical pumping at times of lowest electricity cost (i.e., during the night and on weekends). Again, such investments would have some value under time-of-day pricing, but would be encouraged more by spot pricing.

5. Communications equipment to receive or forecast the spot price. Some small customers may find they can do an adequate job of estimating the spot price based on the day of the week, time of day, and current weather. Most large customers will prefer to install a real-time communications link to the utility (or another source) to learn the current and projected future spot price.

The socially optimum conditions for customer investment are:

Cost of Incremental Investment by Participant j	=	Participant j Magnitude Constraint-Related Gains	+	Participant j Electricity Usage-Related Gains	(7)

It should be noted that the quantities involved in evaluating the above terms are all random variables whose probability distribution generally changes from year to year (or month to month). Thus, expected incremental benefits should be discounted over the life of the investment.

The conditions of eq. (7) are identical to individual participant profit maximization conditions if social and private discount rates are equal. Thus, optimal spot pricing can be shown to internalize system costs and benefits and yield identical social welfare and profit-maximizing investment behavior. Hence, spot price participants are expected to exhibit socially efficient investment behavior.

2.4.C) Customer Investment Under Predetermined Prices

As already mentioned, predetermined price participants will represent a substantial segment of customers, especially during the initial stages of spot price implementation. Therefore, analysis of their behavior is particularly useful for evaluating conditions which are expected to prevail during a transition period. The socially optimum investment behavior does not coincide with individual participant profit-maximizing behavior. Socially efficient behavior should satisfy the following relationship:

Cost of Incremental Investment by Participant j	=	Deviation of Spot and Pre-determined Prices Related Term	+	Participant j Magnitude Constraint Related Gains	+	Participant j Electricity Usage and Rationing Cost Related Gains

(8)

The last two terms of eq. (8) are similar to those in eq. (7). The second term involves predetermined rather than spot prices and the third includes the impact of incremental investment on easing rationing costs. The last two terms in (8) represent profit maximization investment conditions. The first term is an additional impact of incremental participant investment on social welfare which is not realized by individual predetermined price participants. This term equals the expectation of the difference between the spot and predetermined price times the impact on demand of incremental investment. Recalling that the social welfare maximizing predetermined price in eq. (5) equals the expected value of the spot price plus a covariance term, socially efficient investment can be shown to diverge from individual participant profit maximizing investment and achieve different incremental investment benefits. The difference in the incremental investment benefits is proportional to the following two covariance terms: the covariance between the spot price and demand response to incremental changes in the predetermined price and the covariance between the spot price and demand response to incremental investment. Depending on the particular characteristics of each customer, the covariance terms may be positive or negative, inducing higher or lower investment than is socially optimum. Empirical investigation is necessary to determine the actual value of these covariance terms for different customers (or groups of customers) An appropriate subsidy policy can be subsequently designed to induce socially optimal investment behavior by predetermined price participants. A final note concerns the fact that the value of the covariance terms can be made as small as desired by increasing the frequency with which predetermined prices are updated (every month or every week rather than every year) as well as their differentiation by time of use (different rates for each hour of the day as opposed to day and night rates only). The criterion for determining the optimal update frequency and time differentiation is the trade-off between transaction, metering and communications costs on the one hand and social welfare gains on the other. Availability of a wide range of pricing options and comparison of welfare gains with metering and communication costs associated with shifting from one option to another may yield a socially optimum process for assigning customers to pricing options. However, individual participant self-selection of pricing options will not always yield the socially efficient grouping described above.

2.5. Decentralized Operation and Investment

The theory of spot pricing was presented in Section 2.2 for a utility which owns and operates the T and D system and all its generators. The theory also applies to situations where independent competitors own and operate a large amount of generation. Spot prices are calculated by the same formulas as before, and act as signals to generators to adjust their output levels in response to changing supply and demand conditions where their internal thermal requirements will allow for it. If the unconstrained generating firm is a perfect price taker, full spot prices lead it to self-dispatch exactly as if it were centrally owned. The social value of a generation expansion for a given generating unit is also the expected private profitability of the expansion if the unit were independently owned and paid optimal full spot prices at all times. Thus, to a first approximation, competitive generating firms under full spot pricing would behave as if owned by a welfare maximizing monopolist. Thus full spot pricing can, at least in theory, replace economies of scale due to unified ownership of generation.

Naturally, to the extent that perfect competition by generators does not exist in an electricity spot market, behavior of independent firms will deviate from social welfare maximizing behavior even if properly calculated full spot prices are used. There are at least four plausible deviations of a spot market from a perfectly competitive market.

- The remaining central utility has strong market power, even if it is confined to calculating full spot prices and building and controlling the T and D system. While supply and demand forces will determine prices at each instant, a central utility could reconfigure or underbuild the T and D system to increase spatial price differences and its net revenues. Without regulatory auditing it can also simply miscalculate prices, as long as it does so in a way which maintains the energy balance constraint. This is not fundamentally different from the basic regulatory revenue reconciliation problem of controlling the behavior of a traditional utility using marginal cost rates. Full spot pricing with decentralized ownership of generation does <u>not</u> eliminate the need for regulating the owner of the T and D system.
- Individual generating firms might own enough capacity in a region to affect the system's marginal generating cost at certain times. This type of market power is traditionally dealt with by antitrust action.
- Each generator or customer will have some spatial market power. The magnitude of this effect depends on the strength of the T and D system.
- Economies of scale in unit capital costs can lead to construction of units large enough to affect local prices; private investors will then size new units slightly below the social optimum. They will

also retard construction of new units in the face of growing demand.

The above problems occur to some extent in many unregulated U.S. markets which have lumpy investment and significant transport costs for their products. But the feasibility and desirability of fully decentralized ownership of electricity generation has other potential problems, such as the need for accurate real-time competitive market clearing. The purpose of the discussion here is mainly to point out the possibility of a mixed system of central utility and competitive ownership of generators, and the need to use full spot prices to achieve efficient coordination in such a system.

2.6. The Revenue Reconciliation Problem

One concern in applying optimal spot pricing is satisfying the regulatory imposed revenue requirement or profit constraint in an efficient manner. The overall profit constraint is defined within a standard cost accounting framework: gross revenues minus fixed and variable costs should provide a fair return to equity capital. The fixed cost includes depreciation of capital stock based upon historical (embedded) costs and debt service. Variable costs include fuel and other operating expenses. The revenue requirement framework is the primary means for controlling the profits of public utilities. The revenue reconciliation problem is further complicated by the traditional practice of basing revenue requirements for separate customer classes on fully distributed accounting costs. The procedures for allocating the accounting costs of production to determine class revenue responsibility have little relationship to marginal cost pricing principles. Therefore, revenues derived from marginal cost pricing for each individual customer class would lead to a relative shift in revenue responsibility among the various customer classes. The distribution and magnitude of these potential intra-class revenue impacts will be a concern of the customers.

These issues represent the major battle ground of today's regulatory proceedings. While basing all rates on spot prices will in theory eliminate these cross subsidies, the process of moving to spot price based rates will raise the issue to the fore where it will cause a heated debate.

The general problem of efficiently constraining prices to meet a budget constraint has been vigorously debated in the economic literature. Hotelling's [1938] article considered the problem of financing public works such as bridges where the marginal cost of crossings are usually trivial. His answer to the pricing problem was to set prices at marginal cost and to finance the fixed cost of the bridges through taxes which (ostensibly) would not distort consumption decisions, such as income taxes or inheritance taxes. Coase [1946, 1970] argued that from a broad public policy perspective, user support was an important market test for efficient allocation of resources and thus fees should cover the total cost of the enterprise. He suggested the use of multi-part tariffs (such as declining block rates or a fixed fee plus a commodity charge) as an alternative to government subsidies. Vickery [1955] stressed that a misallocation of resources can result if marginal cost pricing principles are not followed. Baumol and Bradford [1970] proposed optimal departures from marginal cost pricing with a generalization of Ramsey's [1927] rule. A much discussed special result of their analysis is the "inverse elasticity rule."

> If the cross price ellasticities of demand between the commodities in question are zero, then the percentage deviations in price from marginal costs should vary in inverse proportion with the own price elasticity of demand.

If cross elasticities are not zero, a somewhat analogous rule still holds. Relative TOU prices can be adjusted according to the Ramsey rule if sufficient information is known about price elasticities. More recently proposals for non-linear pricing or multipart tariffs (see e.g., Willig [1978]) have been suggested to be Pareto superior to the Baumol and Bradford rules.

One possible "nonlinear" pricing scheme would be a two-part tariff where the commodity charge is set equal to marginal costs and the fixed charge is set to assure revenue requirement recovery. A problem with such two-part tariffs is that the fixed fee can fall disproportionately on smaller customers. If, however, the fixed fee is set in strict proportion to the current consumption for purposes of equitably allocating the deficit, the effect is a proportional increase in the commodity charge. This is undesirable on efficiency grounds because marginal prices will then not reflect marginal cost levels. Benchmark tariffs which appear implementable can provide a method of allocating fixed fees proportional to consumption yet retaining marginal costs as the basis for pricing marginal consumption. (See Davidson and Dent [1978] for further discussion and references.) The thrust of the procedure is to tie the fee to a benchmark of historical consumption. All current consumption then is priced at marginal costs. Should the resulting revenue fail to meet the revenue requirement, the difference is made up by a fee set in proportion to the benchmark level of consumption. The benchmark can be fixed, having no effect on marginal prices, or it can be a moving average of past consumption, which will have a discounted effect on marginal prices for current consumption. When the fee is positive, firms with decreasing consumption (due to, for example, conservation measures) will find part of their bill still tied to historical levels of consumption; hence the bill reductions of conservation will not be as great as they would be if the electricity had a uniform price. The equity gains of this pricing system over a uniform fixed fee, however, may be persuasive if a uniform fixed fee would be substantial for small users. The choice among the various reconciliation procedures will depend, in practice, upon the magnitude of the problem. If the problem is relatively small the redistribution positive or negative will be unnoticeable in the total rate virtually regardless of method chosen. If the proportion is great the impact will be great thereby requiring far greater care in reconciliation so as to maintain the goals of efficiency in pricing.

Spot pricing would be a major change in tariff structure. As such, its revenue implications cannot be as confidently estimated as has been the case for traditional rate designs, because of uncertainties about customers' response and resulting consumption patterns. To minimize the potential for adverse revenue effects due to incorrect consumption forecasts on either the utility or the Spot Pricing customer class, it may be desirable to allow for ex post adjustment in bills.

Under traditional utility cost distribution procedures, class revenue requirements are set to "fairly" allocate the fixed and variable costs of service among the various classes. Should these procedures be continued, a special class would have to be created for spot price customers. The revenue requirement for that class could be set as is done presently, with two important considerations. First, since spot price customers will receive more accurate cost information in their prices than will other customers, their consumption patterns could be expected to adjust to lower the variable costs of service for them. Presumably at least a portion of these savings should be passed back to the spot price customers by lowering their revenue requirements. Because this reduction would be directly attributable to lower variable costs, all other classes, as well as the utility, would be no worse off. The existence of a spot price class would provide reliability benefits as well, in much the same way as do industrial interruptible customers and residential customers subject to direct load control. In the long run, this increased reliability would allow lower capacity requirements for the utilities. For the spot price customers, this long-run benefit may be recognized by lowering the fixed costs ascribed to their revenue requirement.

2.7. Comparison of Spot Pricing with Other Public Utility Pricing Models

2.7.A) Introduction

The idea of setting electricity prices on a spot price basis is quite old. It has been used for sales between utilities in the U.S. under the name "economy interchange." Pricing methods containing elements of spot pricing have been implemented for sales to customers on a limited basis by many utilities in the U.S. and Europe.

- Sweden has a complex rate structure for its largest industrial customers which contains many provisions analogous to spot pricing (Camm, 1980).

- o Great Britain adds a price surcharge during periods of anticipated supply shortfalls, or "peak period warnings." This rate is applied to several hundred large customers (Mitchell, Manning and Acton, 1979).
- o San Diego Gas and Electric Company calculates a demand charge for its 23 largest customers based on their demand at the time of system peak. This can be interpreted as a spot price (Bohn, 1980, Gorzelnik, 1979).

The desirability of time of use rates has been the topic of major research by the Electric Power Research Institute [1979]. For a good summary of this effort and discussions of associated problems, see Malko and Faruqui [1980] and Faruqui and Malko [1981a]. For a good review of the U.S. Department of Energy sponsored residential time of use experiments, see Faruqui and Malko [1981b].

Although rates which are effectively spot prices have been in use for some time, the academic literature on spot pricing theory for electricity is less well developed. There is, however, a rich literature on optimal pricing and generation planning for electricity, but it emphasizes predetermined prices ("time-of-day" pricing), or direct utility load control ("load management").

The idea of time differentiated prices goes back at least to Boiteux (1949) (see also Vickrey [1955] and Steiner [1957]). Until Brown and Johnson [1969] the models were purely static and deterministic. During the 1970's various authors presented prescriptions for time-of-use pricing in static models with demand uncertainty. Their analysis can be considerably simplified and generalized by using the concept of spot pricing.

2.7.B) Time of Use Pricing

The "standard" time-of-use pricing models are surveyed in Gellerson and Grosskopf [1980] and Crew and Kleindorfer [1979]. They include Wenders [1976], Crew and Kleindorfer [1976, 1979 Ch. 4 and 5], Turvey and Anderson [1977, Ch. 14], and various predecessors. These models include multiple types of generators and stochastic demand. Some of the limitations of these models are as follows:

- o Generating unit availability is modeled by simply derating unit sizes at all times. This fails properly to penalize large units, and it gives inaccurate estimates of the probability that rationing will be needed. It also gives no guidance for how to evaluate new technologies such as solar and cogeneration, whose "availabilities" are correlated with demands by other customers.
- o There is no analysis of how or when prices should be recalculated. These models rule out frequent recalculations (by spot pricing) by assumption. By assuming infinitely repetitive demand cycles and stable factor prices they show no need for annual or less frequent recalculations. Demand and cost trends are thus not considered.
- o These models treat all investment as occurring at once. Investment is really a sequential process. True utilities never have the static optimal capital stock of these models, because conditions change more rapidly than capital stock turns over. Therefore pricing equations which asume optimal capital stock, i.e. assume that short run and long run marginal costs are equal, have limited practical value. In fact long run marginal costs can only be calculated conditional on a particular

scenario or probability distribution of demand and factor prices. This problem is addressed by Ellis [1981].

- The models assume that demands and generating costs are independent from one hour to another. This is very convenient, since it allows the use of a single load duration curve (or price duration curve). Nonetheless the availability of storage [Nguyen, 1976] or demand rescheduling can have a major impact on optimal prices and investment policies.
- The models ignore transmission, which is equivalent to assuming an infinitely strong transmission system. This is not feasible when setting practical rates for power buybacks, but these models give no insight into how to price over space. Current debates about "wheeling tariffs" indicate the importance of this issue when trying to encourage independent generation by firms located in the territory of a monopolistic utility.
- The models do not use the device of prices which depend on the operating condition of the utility. Therefore, the investment conditions derived in the models are hard to interpret, although they are correct (given the limiting assumptions above). For example, Crew and Kleindorfer [1979, p. 77] interpret their results only for the case of interchanging units which are adjacent in the loading order. Littlechild [1972] showed the way out of this problem, but his point was apparently missed by subsequent authors.

2.7.C) Dynamic Pricing/Investment Models

Several authors present deterministic explicitly dynamic models which can be interpreted as deterministic versions of spot pricing. Crew and

Kleindorfer [1979, Ch. 7] give a continuous time optimal control model with one type of capital. They get the result that:

> Whatever the level of capacity, price is to be set to maximize instantaneous [short run] welfare returns subject to the given capacity restriction. [p 113] [That is,] price should equal SRMC. Of course, at optimum capital stock is adjusted so as to equate SRMC and LRMC....In the event of .... a fall in demand, [optimal] price is less than LRMC, then capacity would be allowed to decline until equality between price and LRMC were re-established.

They are thinking here on a time scale of years, not hours; they reject continuous adjustment of prices to reflect the actual level of demand. Nonetheless, their model can be interpreted in terms of hourly price adjustments.

Turvey and Anderson [1978, Ch. 17] have a discrete time dynamic model which leads to discontinuous prices, as capital investment is made in lumps. However they reject this approach: "It is apparent that, for one reason or another, such fluctuations are unacceptable." They also acknowledge that investment decisions must be made before price decisions, and with more uncertainty about future demands, but they do not incorporate this into their models. [p 305]

Ellis [1981] explicitly models sequential investment and pricing decisions. He concludes that "...welfare optimal pricing rules differ according to whether prices must be set either before or after investment decisions are made." [p 2] He uses dynamic programming to look at how the character of optimal sequential investment depends on capital stock irreversibility and the sequential revelation of information about future demands.

2.7.D) Spatial Pricing

Several previous authors have studied how public utility prices should vary over space. Relevant models include Takayama and Judge [1971] (which was not directed at electricity), Craven [1974], Dansby [1980], Scherer [1976, 1977], and Schuler and Hobbs [1981]. All of these models are deterministic and most are static. Only Scherer has an accurate model of electricity line losses and line constraints, or includes T and D investment options.

Scherer's approach is to use a mixed integer programming model of an electricity generation and transmission network. In his model spatially distinct prices appear as dual variables on demand at each point in the network. In his numerical case study he found that prices between different points at the same time varied by up to 30 percent. The absolute and percentage variations across space changed over time. [1977, p. 265] He does not discuss these results, but presumably they reflect the different losses resulting from different optimal load flows at each level of total system demand.

Much of Takayama and Judge concerns pricing across space. They consider only competitive markets, but use an explicit optimization method of finding equilibrium, so their analysis is equally applicable to a welfare maximizing monopolist. They assume a constant transport cost per unit between two points, no transport capacity limit, and no losses. This makes their models more appropriate for conventional commodities than for public utility products such as electricity. They also assume linear demand and supply functions. But their framework does provide insights into more general spatial and temporal pricing problems. For example they discuss "no arbitrage" conditions which bound the price differences between different locations.[1971, p 405] Their models do not include capital, so they provide no insights into optimal investments in transport facilities.

2.7.E) Pricing of Reliability

One way to view spot pricing is that it allows customers to choose their own reliability levels. Marchand [1974] has a model in which customers select and pay for different reliability. The utility allocates shortages accordingly, when curtailment is necessary. His approach differs from (and is, except for transactions costs, inferior to) spot pricing because customers must contract in advance, and therefore have no real time control over their level of service. Also, customers not curtailed by the utility have no incentive to adjust demands.

A simple version of Marchand's proposal is in use in the U.S. and elsewhere. Called "direct load control", it involves the utility turning off specific equipment of the customer's. Despite its increasing use [Morgan and Talukdar, 1979; Gorzelnik, 1982] optimal pricing and use of direct load control has not been extensively studied by economists. (Note, however, Berg [1981] and Dams [1979].)

2.7.F) Spot Pricing

Spot pricing of public utility services was first proposed by Vickrey, under the name "responsive pricing". His original article [1971] presented a general discussion using as examples mainly long distance telephones and airlines. The emphasis is on curtailment premia, rather than on marginal production cost changes over time. Later manuscripts on electricity develop the ideas in more detail, including some discussion of optimal investment criteria [Vickrey, 1973 p 12], metering requirements and designs, pricing of reactive energy, and short run marginal operating costs (system lambda). He proposes that utilities be free to set prices however they want over time, subject only to limits on total profits.

Vickrey's essential insight was that prices can be set after some random variables are observed, and optimal prices should reflect this. Since his original article different versions of this basic idea have been developed independently and under different names, with varying levels of rigor. These include:

- "State preference" approach to pricing electricity [Littlechild, 1972], a formal stochastic model of both pricing and investment under static conditions. Both operating costs and capacity constraints are modeled, but with homogeneous fixed coefficient technology, i.e., only one kind of capital.
- "Time varying congestion tolls" for a highway or communications network. [Agnew, 1973; 1977] A formal deterministic optimal control model incorporating only capacity constraints and delays. No discussion of investment.
- "Spot pricing" of electricity. [Schweppe, 1978; Schweppe et al. 1980, 1978; Bohn et al., 1981; Caramanis et al. 1982].
- "Real time pricing" of electricity. [Rand, 1979] Informal; no specific proposal.
- "Load adaptive pricing" of electricity. [Luh et al, 1982] A game theoretic model; nonlinear prices allowed. Quadratic production costs assumed, with no capacity constraints and no investment. Their formulation allows for games between one utility and one consumer which is <u>not</u> a pure price taker.

o "Flexible pricing" of electricity. [Kepner and Reinbergs, 1980] Informal.

Many other authors have explicitly rejected the idea that prices can be set after events are revealed. For example, Crew and Kleindorfer [1980, p 55] write: "For the case of the regulator setting the price ex post, he or she would either have to allow a market-clearing price or have some deliberate arrangement for setting the price above or below the market clearing price. Were the regulator [to allow] the market clearing price, he would, in effect, be giving up his right to regulate price." Turvey and Anderson [1977, p 298] are even more adamant in their rejection of spot pricing:

> ...for a wide class of random disturbances (but not for all), it is not possible to respond to the resultant random excess or shortage of capacity by adjusting prices. Failure of a generating plant on Thursday cannot be followed by a higher price on Friday, and the price in January cannot be raised when it becomes apparent that January is colder than usual. Even though telecontrol makes the necessary metering technically possible, it would be expensive, and... there would be difficulties in informing consumers of the new price. It would also be scarcely possible to estimate its market clearing level. Sudden and random price fluctuations would in any case impose considerable costs and irritations on consumers. Hence responsive pricing that always restrains demand to capacity is not practical, and some interruptions are thus desirable.

Their rejection thus appears to be based on the belief that the transactions costs of spot pricing would outweigh any possible benefits.

2.8. Summary

This chapter has developed the logic of spot pricing and covered in detail a significant number of ancillary issues ranging from independent generation to revenue reconciliation. In addition it has presented a review of much of the literature which has developed over the past two decades which has pointed either positively or negatively toward the potential for pricing of electric energy which reflects more accurately the time varying costs of generation. There are two major conclusions to be drawn from the theoretical develoments. The discussions of ancillary issues and the review of the literature. These are the advantages of spot pricing and the benefit/cost issues on implementation.

Looking only at the theoretical discussion presented in the early portions of this chapter there is little argument that can be raised against spot pricing being the economically and thereby physically efficient approach to pricing of electric energy. The ability of the customer to choose his level of service via the price signal and thereby his level of reliability is critical in the operation of an efficient marketplace. The ability of spot pricing to act symetrically between purchase and sale of energy offers another major advantage. The advent of PURPA has had an impact on the already difficult issue of setting prices for utility buyback of energy from small and cogenerators. Spot pricing provides both the theory and the practical means of setting and maintaining those prices.

The second issue is that of implementability and the critical relationship between the benefits from increasingly short spot price update cycles and the costs of communications, metering and control. It is clear that a number of writers who recognized the potential for spot prices did so at a time when it could not be implemented because of major hardware limitations. It is also clear that writers such as Turvey have rejected, *a priori*, the concepts of spot pricing because they believed that the costs would exceed the benefits. The arguments made in this report, specifically in the next two chapters, indicate that the benefits from spot pricing are more than sufficient to justify from a societal perspective the investment, for at least large customers, in the communications, metering and control equipment. Given lower cost energy control and management capabilities, the major issue is which of the spot pricing time cycles will be appropriate to which individual customer or customer class. It appears that industrial customers will find this an attractive alternative with advantages beyond the current time of use rates. Large commercial customers are also likely to be able to take advantage of the short time periods. Smaller custmers will benefit from slower time cycles. The analysis of the benefits from response will determine in large part the economic advantage from participation. These issues will require empircal effort beyond the simple benefit analysis discussed in the two following chapters.

CHAPTER 3

FRAMEWORK FOR INDUSTRIAL CUSTOMER/UTILITY BENEFIT ANALYSIS

3.1 Introduction and Simulation Model Overview

The objective of this chapter is to present the background and modeling structure for an analysis of the potential benefits from spot pricing applied to the industrial sector in the prototype Wisconsin utility. The previous chapter presented the theoretical arguments for spot pricing. This chapter presents the analytic structure and Chapter 4 which follows presents the results of the initial model analysis.

The analysis presented focusses on the following set of questions:

- What are the levels of likely benefits from spot pricing implementation
- How do benefits compare to costs of metering and communications required for spot pricing implementation
- How are the benefits of spot price implementation likely to be distributed among consumers and generators of electricity
- How does the ability to respond affect benefits and their distribution among consumers and generators
- How does the type of available generating capacity and fuel mix affect benefits and their distribution
- Does the existing generating capacity stock deviate substantially from the optimal composition under spot pricing If so, in what types of generation has there been overinvestment or underinvestment

A simulation model was used to address these questions. Customer and utility operating data were obtained from Wisconsin Electric Power Company (WEPCO). The generating system's performance and cost characteristics, actual time-of-use rates and hourly demand levels for

1980 were used. Energy purchases from neighboring utilities were not considered. (The contracts under which economy transactions were made in 1980 are not anticipated to hold during future years.) Large industrial customers accounting for approximately one-fourth of total demand, were selected as the most suitable candidates for spot pricing. Their demand behavior as a function of spot prices was simulated under assumptions of high and low responsiveness. The demand response algorithm was imbedded in an hourly Monte Carlo simulation production costing model in order to investigate the interaction of demand response and marginal generating costs. The overall structure of the simulation model is presented in Figure 3.1 and its components, input data and results described later. The following quantities of interest are estimated by the simulation model.

- Variable generating costs
- Total energy generated
- Reliability in terms of unserved energy and loss of load hours
- Fuel consumption by fuel type
- Energy demanded by industrial customers
- Changes in industrial production cost (electricity) under spot pricing compared to the costs incurred under the present pricing practice
- Generating unit-specific variable operating costs
- Value of electricity supplied by each generator weighted by the spot price.

The above quantities allow calculation of spot pricing benefits and their distribution among participants (generators and consumers). The difference between the value of electricity (supplied by a particular

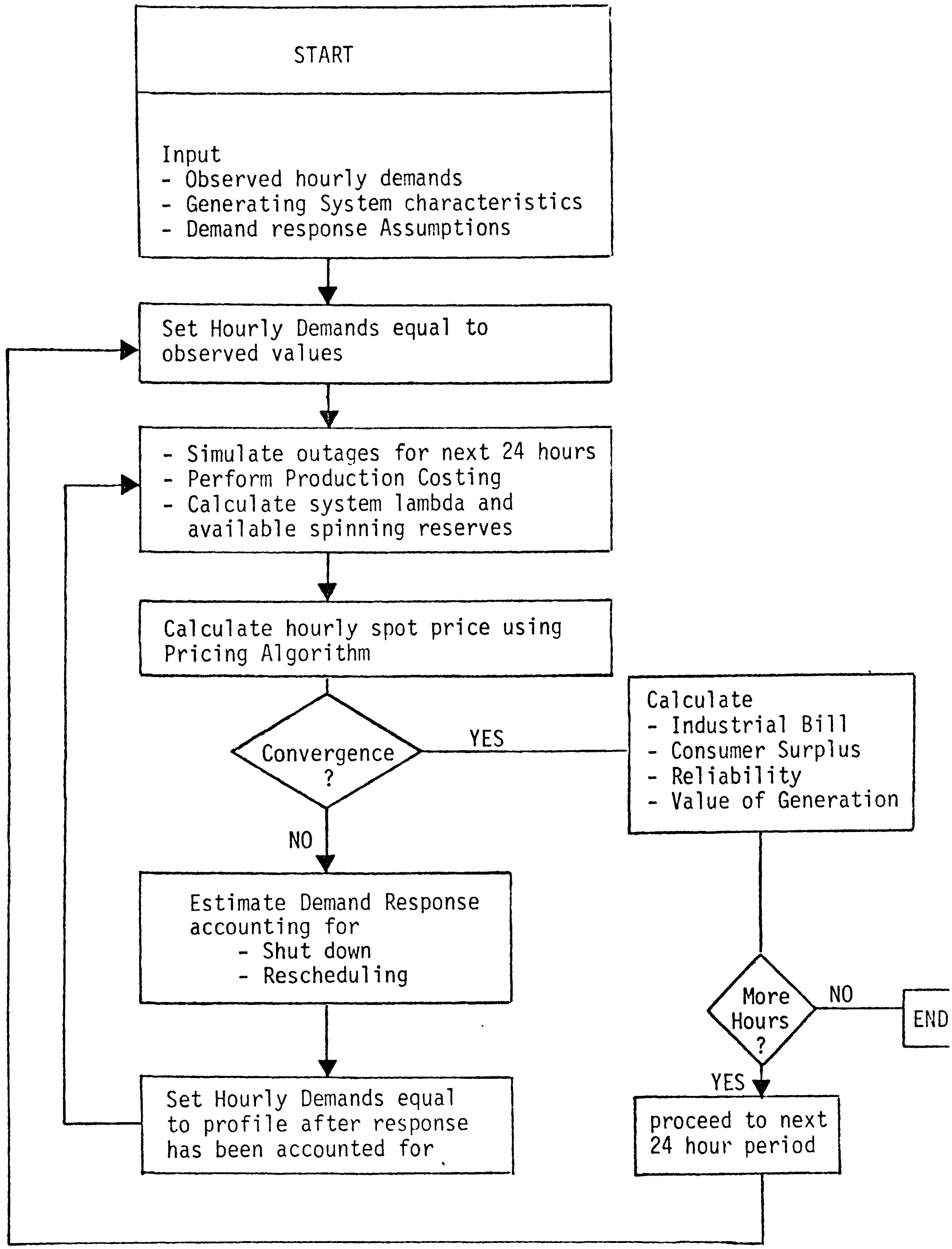


Figure 3.1

OVERVIEW OF THE SIMULATION MODEL

unit) and its generating costs are a measure of the unit's contribution to social welfare. If that contribution exceeds the fixed costs (O+M and capital) of building and operating an additional unit of that type, it is an indication of underinvestment in that type of generting capacity. Excess of fixed costs, on the other hand, is an indication of overinvestment.

A number of simulations were carried out corresponding to different scenarios representing variations over total demand level, industrial consumer type and level of response, and finally different generating unit fuel costs.* The overall simulation model presented in Figure 3.1 consists of the following steps:

Step 1 - Input data on:

- Hourly industrial demand (HID) and hourly non-industrial demand (HNID) observed in 1980 with the present (time-of-day) pricing practice.
- Generating system characteristics, operating costs, etc.
- Demand response assumptions and values of parameters of demand response algorithm.

Step 2 - Set HID and HNID equal to observed values.

Step 3 - Simulate generating unit outages for a 24-hour period and perform production costing to meet hourly demand. Calculate hourly marginal generating costs (system lambda) and available spinning reserves.

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*The WEPCO generating unit fuel costs were modified in some of the simulations to model a system more heavily dependent on oil than the actual WEPCO system.

Step 4 - Calculate hourly spot prices as a function of hourly marginal generating costs (system lambda) and available spinning reserves.

Step 5 - Check for convergence. If all 24-hourly spot prices are equal to the prices (spot or TOD if in the first loop) corresponding to the values of HID used then:

- Calculate aggregate industrial consumption electricity bill under the constant total consumption assumption.
- Calculate aggregate industrial consumers' surplus (relative to TOD prices) under the constant expenditure share assumption.
- Calculate social value of electricity supplied by each generating unit weighting supply by spot prices.
- Proceed to next 24-hour period (Step 3) until all days of the year are exhausted.

If one or more hourly spot prices differ from those corresponding to the HID used, then proceed to Step 6.

Step 6 - Simulate HID corresponding to hourly spot prices calculated in Step 5. The simulated HID values are estimated by the demand response algorithm as a function of response assumptions and parameter values, TOD rates, the observed HID values, and the spot prices from Step 5.

Step 7 - Revise HID values to those simulated in Step 6 and go to Step 3.

The simulation algorithm described above was used to generate the results presented here. Due to the computational burden involved, however, the number of loops used for convergence was limited to a maximum of two. As expected, convergence problems were more noticeable when high response parameters were specified.

The remainder of this chapter presents the details of the algorithms that made up the simulation model and the data and assumptions used in the analyses.

3.2 The Pricing Algorithm

The optimal pricing rule developed in Chapter 2 and Caramanis et al. [1982] provides the specifications for real-time price setting based on marginal system operating costs, energy balance (market clearing) and transmission and distribution (T+D) network constraints, as well as participant-specific incremental impacts on system losses.

In the simulations reported here, however, losses and T+D-related components of the optimal spot price were not included. To include them would have required solving an optimal load flow problem for each hour, a practical impossibility given the available resources. In addition, the energy balance (market clearing) constraint is not always met by the initial choice of spot prices.* The initial choice of the spot prices is a guess at the price that results in supply matching demand without violating the spinning reserve requirements. Demand is determined as a function of the previous guess of the spot price. In equation terms we have:

*In terms of the discussion of Chapter 2, the spot price used in this modeling effort includes only variable operating costs and quality of supply, not T and D, losses or transaction costs.

$$P_t^k = \begin{cases} x = MC_t(D_t^{k-1}) + \mu_t & \text{if } x \leq 1.5 \\ 1.5 & \text{otherwise} \end{cases}$$

$$\mu_t = \begin{cases} 0 & \text{if } D_t^{k-1} - (G_t^{max} - SR_t) \leq 0 \\ (\$1 - MC_t)[D_t^{k-1} - (G_t^{max} - SR_t)]/SR_t & \text{otherwise} \end{cases}$$

where:

P_t^k: kth spot price guess for hour t; t = 1, 2, ..., 24.

D_t^{k-1}: Demand at hour t derived in terms of the k-1 spot price guess.

MC_t: The marginal generating cost (system lambda) during hour t given forced outages and demand equal to D_t^{k-1} or G_t^{max}, whichever is smaller.

μ_t: Quality of supply premium during hour t. It is zero when available generation exceeds demand plus spinning reserve requirements.

SR_t: Spinning reserve requirements at hour t.

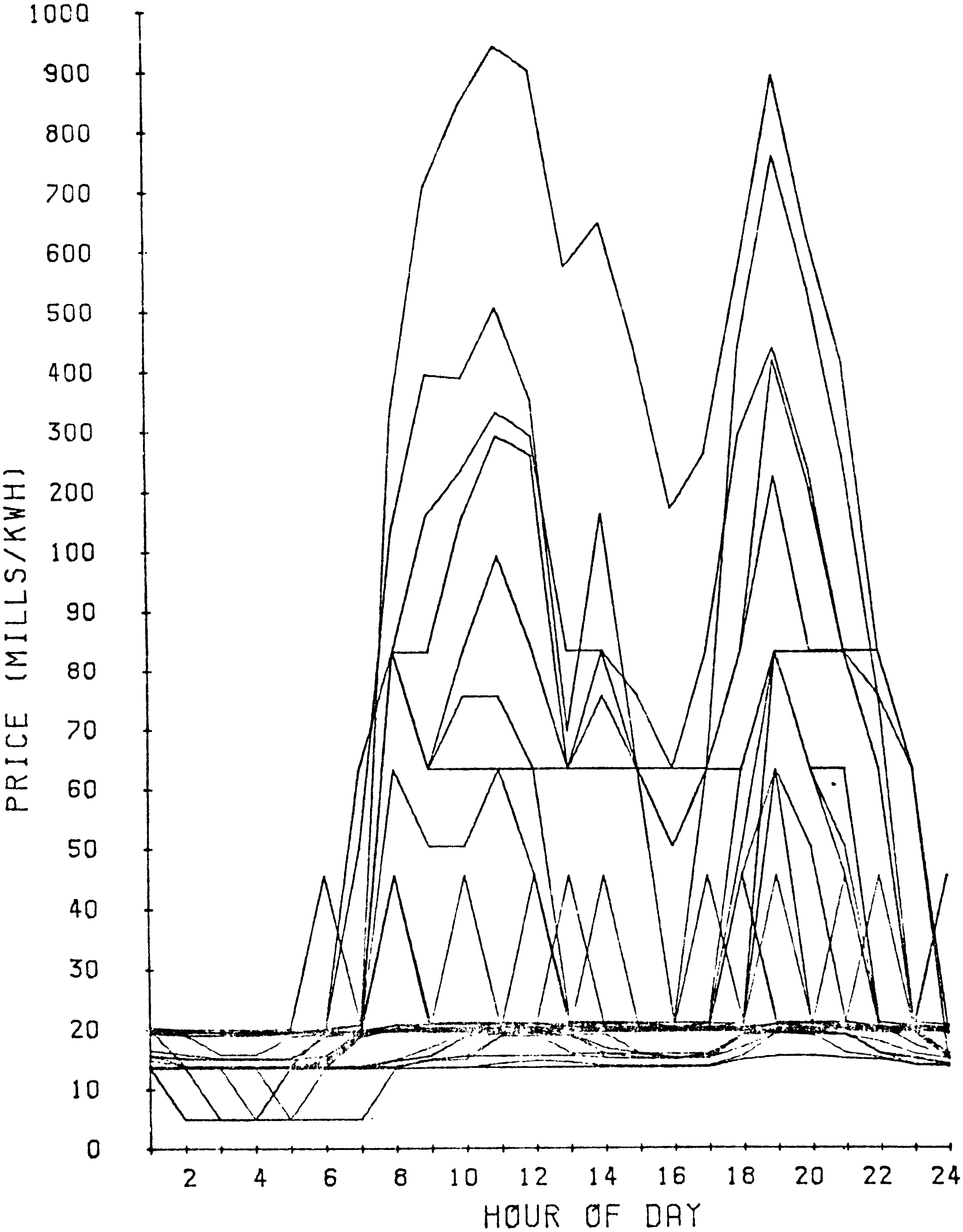
G_t^{max} Maximum available generation/purchase for hour t.

The above specification which is consistent with the discussion in Chapter 2 provides the means for a successive approximation of the optimal spot price which converges to the optimum market clearing level for a sufficient number of iterations. It can be interpreted as follows: the spot price is set equal to marginal generating costs as long as enough generation is available to meet demand plus spinning reserve requirements. Whenever demand plus spinning reserve requirements exceed available generation, a quality of supply premium is added to the spot price. The premium is a linear function of the difference between available generation and demand plus spinning reserve requirements. When demand exceeds available generation minus spinning reserves the spot price increases beyond the marginal cost as a linear funtion of demand. It attains the value of $1/KwH when demand equals available generation driving spinning reserves to zero and continues to increase with demand to a maximum value of $1.50/KwH. It has been assumed that at this price, i.e. $1.50, that non spot price customers would be shed from the system. Figure 3.2 shows graphically the trajectory in price that would be calculated in the model. It should be noted that the total system capacity and the reserve margin are a function of the availability of generating plants and therefore are not constant for the prototype utility. The precise values for quality of supply and the point at which non spot price customers would be shed from the system would, in practice be set from empirical data gathered from experience in operating the system. The values chosen in this study are based on limited information concerning the costs associated with shortage and with addition of additional peaking capacity. These numbers must be seen as first approximations for the purpose of this analysis and not as either estimates of the cost of capacity on the Wissconsin system or of the measured value of energy to Wisconsin industrial customers.

Figure 3.3 shows an example of 42 daily price trajectories for the system being studied. As can be seen, the price on lone day did reach the $1.00 per KwH though once again it msut be pointed out that the system evaluated was not assumed to have intertie power available.

Figure 3.2

EXAMPLES OF HOURLY SPOT PRICE TRAJECTORIES



3.3 The Demand Response and Consumer Surplus Estimation Algorithms

The demand response algorithm used in the simulation model yields aggregate hourly industrial demand profiles over a 24-hour period. These profiles are derived as functions of actual aggregate hourly industrial demand profiles observed during 1980 under time-of-day prices. The actual profiles are first modified for the effect of spot prices on "shutdown loads." Shutdown loads are small portions of total demand which can be dropped at times of high prices (for example, reduction in lighting). Table 3.1 gives the parameter values used for modeling shutdown load. After shutdown loads have been removed, the remaining demand is rescheduled to reflect shifts in consumption due to spot prices varying over time. This rescheduling is done by employing the demand response algorithm.

The parameters of the demand response algorithm are calibrated to meet the following conditions:

a. When prices equal their 1980 TOD values, then the demand response algorithm should yield the observed electricity hourly demands after shutdown and the exogenously specified cross elasticities of substitution between electricity consumed at different hours of the day.

b. The total consumption of electricity over any 24-hour period starting at 12 pm should be invariant to the actual trajectory of spot prices during the same period.

It should be noted that condition (a) specifies cross-price elasticities of demand, while condition (b) specifies by a residual method own-price elasticities of substitution that satisfy the "constant consumption" assumption. The own-price elasticities of substitution

Table 3.1

Shutdown Load Parameters Used

x_1	x_2	Reduction
0	1.2	0
1.2	2.0	.01
2.0	4.0	.02
4.0	6.0	.03
6.0	10.0	.05
10.0	14.0	.10
14.0	20.0	.12
20.0	50.0	.14
50.0	70.0	.20
70.0	100.0	.30
100.0	100.0	.50

Note: Shutdown load is simulated as follows: If spot price is less than x_2 times TOD price but more than x_1 times TOD price, then shutdown load equals reduction times original demand.

obtained in this fashion are very close to zero. The "constant consumption" assumption is quite restrictive since it forces total consumption to remain the same over a daily rather than over a weekly, monthly, or yearly period which may be a more realistic requirement. It is used, however, as a very conservative model of reality aimed at producing lower bounds of potential benefits.

Consumer surplus estimates are obtained by specifying a minimum cost function for the aggregate industrial production. The minimum cost function is specified in terms of factor input prices and the industrial output level. The prices of factor inputs other than electricity and the industrial output level are assumed to be invariant to changes in the price of electricity. The parameters of the minimum cost function are selected so that they satisfy the following conditions:

a. When prices equal their 1980 TOD values, then the minimum cost function should yield the observed 1980 factor input cost shares and the exogenously specified cross-elasticities of substitution.

b. The total production cost share of expenditure for electricity over any 24-hour period starting at 12:00 pm should be invariant to the actual trajectory of spot prices during the same period.

It should be noted that condition (a) specifies cross-price elasticities of demand which are equal to those in the demand response algorithm. Condition (b) specifies by a residual method own-price elasticities of demand which are consistent with the "constant expenditure" assumption. The own-price elasticities thus defined are substantially larger than those in the demand response algorithm and their magnitude is close to unity.

The "constant expenditure" assumption used in obtaining consumer surplus estimates represents a much more optimistic assessment of customer response capabilities than was used in the demand response algorithm. The constant expenditure assumption implies a unitary cross-elasticity of substitution between electricity and other factor inputs which is characteristic of a Cobb-Douglas production function relationship. Studies of U.S. manufacturing (Berndt and Wood [1979]) have shown short-run cross-elasticities of substituion between energy and capital to be very small or negative, while between energy and labor they are large and positive. Given the nature of the behavior simulated here and the fact that short-term own-elasticity of demand for energy is generally observed to be smaller than unity*, the constant expenditure assumption should be interpreted as optimistic and the consumer surplus estimates obtained as upper bounds.

The algebraic structure and parameter calibration of the demand response and consumer surplus algorithms are presented below:

The algebraic form of the demand response algorith is the following:

$$D_i = D^*[D_i^* + \sum_j b_{ij} \ln(PS_j/PP_j)]$$

where:

i,j:	indices spanning the 24-hour period, 1, 2, ..., 24
D_i:	rescheduled demand in hour i
D^*_i:	observed demand during hour i
D^*:	total observed demand over 24-hour period
PS_j:	the spot price during hour j

*Although long-term estimates are very close to unity (see Pindyck and Rotemberg [1982]).

PP_j: the time-of-day pricing during hour j

b_{ij}: parameters to be calibrated.

Estimation of spot prices PS_j follows the pricing algorithm procedure presented previously. The time-of-day prices PP_j are obtained from the 1980 energy and demand charges for industrial customers by using the relationships:

$$PP_k = \text{ENERGY CHARGE} + \frac{\text{DEMAND CHARGE}}{\text{LOAD FACTOR} * \text{HOURS}}$$

$$PP_l = \text{ENERGY CHARGE}$$

where

k:	index of hours during the on-peak period
l:	index of hours during the off-peak period
LOAD FACTOR:	the monthly load factor during the on-peak period
HOURS:	the number of hours during a month that comprise the on-peak period.

The above relationships convert the present two-part tariff into a related one-part tariff which varies between on-peak and off-peak periods. Since the demand charge varies between summer and winter months and the load factor varies from month to month, the PP_j values also vary from month to month. Table 3.3 presents the determinants of PP_j in the various scenarios considered.

The values of the parameters b_{ij} are calibrated as follows:

$$b_{ij} = \begin{cases} \sigma_{ij} \cdot (D_i^*/D^*)(PP_i \cdot D_i^*/C) & \text{for } i \neq j \\ - {}_{k \neq j}\, b_{kj} & \text{for } i = j \end{cases}$$

where

σ_{ij}: The cross-elasticities of substitution, an exogenous input

C: The total cost of industrial production over the 24-hour period.

Note that the off-diagonal elements of the parameter matrix b_{ij} (i,j = 1, 2, ..., 24) are calculated first. The diagonal elements are then calculated by the residual method so that the "constant consumption" assumption requiring $\sum_i b_{ij} = 0$ for all j, is satisfied. It should also be noted that the price elasticities of demand denoted by ε_{ij} are:

$$\varepsilon_{ij} = b_{ij}(D^*/D_i^*) \text{ for all } i,j$$

The cross-elasticities ($i \neq j$) are related to the exogenously specified σ_{ij}. Substituting the definition of b_{ij} for $i \neq j$ in the equation above we have:

$$\varepsilon_{ij} = \sigma_{ij}(C/PP_i \cdot D_i^*) \text{ for } i \neq j$$

The consumer surplus estimates are based on the specification of a minimum cost relationship expressed as a function of hourly prices and total industrial output. The minimum cost function is defined as the solution of the optimization problem

$$\min_{X_i} \quad C = \sum_i P_i X_i$$

$$\text{subject to } Q(X_i;\ i = 1, 2, \ldots, T + M) \geq \overline{Q}$$

where

i: index of factor inputs (i = 1, 2., ..., T, T+1, ..., T+M) with T = 24. Values between 1 and 24 refer to electricity consumed during each hour of the day while values larger than 24 refer to other factor inputs.

X_i, P_i: Factor input i and its price respectively.

$Q(X_i;\ i = 1, 2, \ldots, T+M)$: production function relating factor input utilization to output level

$\overline{Q}$: desired production level.

The solution to the above minimization problem must satisfy T+M first-order conditions on the X_i's. These conditions can be used to express the solution in terms of the output level $\overline{Q}$ and the factor input prices. The minimum cost function thus obtained can be approximated by a second-order Taylor expansion after a logarithmic transformation of variables, known as the translog cost function form (Christensen et al. [1973]). Denoting the minimum cost function by C* we have:

$$\ln C^* = V_0 + V_Q \ln \overline{Q} + \sum_i a_i \ln(P_i) + \frac{1}{2} \sum_i \sum_j a_{ij} \ln(P_i) \ln(P_j)$$

$$+ \sum_i a_{iQ} \ln(P_i) \ln(Q) + \frac{1}{2} a_{QQ} (\ln Q)^2$$

Noting that the prices for i,j larger than 24 do not change and that the constant total electricity expenditure share implies* $\sigma_{ij} = 0$ for $i \neq j$, $i > 24$ and $j < 24$, it can be shown that

$C^*(PP_j;\ j = 1, \ldots, 24) - C^*(PS_j;\ j = 1, \ldots, 24) =$

= Consumer surplus change when going from present prices (TOD) to spot prices

= $C \cdot [1 - e^{\Delta}]$

where

C: total cost of production under TOD prices (taken to be approximately 100 times the 1980 observed electricity expenditure over each 24-hour period

*This can be easily seen if the derivatives with respect to the logarithm of prices is taken yielding expenditure share equations.

and

$$\Delta = \sum_j a_j \ln(P_j) + \frac{1}{2} \sum_i \sum_j a_{ij} \ln(P_i) \ln(P_j) \text{ for } i,j = 1, 2, \ldots, 24.$$

The parameters used in estimating Δ are calibrated as

$$a_j: \quad PP_j D_j^* / C$$

$$a_{ij} = \begin{cases} (\sigma j_{ij} - 1)(PP_j D_j^*/C)(PP_i D_i^*/C) & \text{if } i \neq j \\ \\ - \sum_{k \neq j} a_{kj} & \text{if } i = j \end{cases}$$

Note that the off-diagonal elements of the parameter matrix a_{ij} are estimated first. The diagonal elements are then calculated by the residual method so that the "constant expenditure" share assumption requiring $\sum_i a_{ij} = 0$ for all j is satisfied. To compare the consumer surplus calculations to the demand response algorithm it should be noted that cross-elasticities of demand and substitution are identical when prices equal their TOD levels. The own-price elasticity of demand however given in the context of the minimum cost function by

$$\varepsilon_{ii} = a_i - 1 + a_{ii}/a_i$$

are significantly different and larger in magnitude than those in the demand response algorithm.

3.4. The Production Cost and Reliability Algorithm

The proper simulation of the costs and benefits of spot pricing requires a detailed production cost and reliability model. Since demand response under spot pricing depends on the hour-by-hour prices over a daily cycle, a consecutive hour-by-hour production cost and reliability analysis is required.

The ENPRO production cost model was used in this analysis. This model does an hour-by-hour simulation of each day for each week of the year. It is an hourly load following program as opposed to a program that dispatches load along the load duration curve.

ENPRO allows for a detailed specification of each generating unit including:

1. Changing heat rates with level of output.
2. Variable operating and maintenance costs.
3. Fixed operating and maintenance costs.
4. Fuel costs.
5. Forced outage rates.
6. Maintenance requirements.
7. Minimum load requirements.
8. Variable maximum output by hour of the day.
9. Seasonal deratings.
10. Contribution to spinning reserve.

ENPRO has been interfaced with the pricing algorithm, the demand response algorithm and the consumer surplus estimation algorithm described above. It has thus incorporated the essential functions for modeling spot pricing response and the resulting benefits.

Production costing and reliability calculations are based on Monte Carlo simulation techniques. The availability of any unit for a particular day for a particular Monte Carlo iteration is based on a "draw" from a random number set. Using this technique, the performance of the generation system for a given day is calculated repeatedly for the specified number of iterations (eight in this case). The individual hourly results are then summed to provide the expected value results. Such an approach is particularly useful when looking at spot pricing since unusual combinations of unit forced outages and load levels are examined explicitly.

The output of the model includes a detailed summary of system reliability. Annual hours of capacity deficiencies and the number of capacity deficiencies by hour of the day by month are an output from the model. In addition, the magnitude of the capacity deficiencies (unserved energy) are calculated by hour of the day and by month and are summed over the period of analysis.

Detailed output is also provided for system cost and fuel use. Cost and energy output data are tabulated on a unit-by-unit basis. Fuel usage by type is also calculated.

3.5 The Data Used

The data used in the simulations consist of hourly demands of WEPCO industrial and non-industrial consumers during 1980, industrial time-of-day rates, demand response parameters, and generating system characteristics.

The peak and energy values of demand used are given in Table 3.2.

Table 3.2

GENERAL DEMAND CHARACTERISTICS

	Low Demand Scenario		High Demand Scenario	
Customer Group	Peak MW	Energy GWH	Peak MW	Energy GWH
Industrial	787	5010	826	5257
Non-Industrial	2496	13164	2621	13824
All	3283	18174	3447	19081

The low demand scenario coincides with the actual 1980 observations while the high demand scenario was constructed by increasing each hourly demand by 5 percent.

The time-of-day rates used for the low demand WEPCO case were these in effect on October 9, 1980. The energy charges were adjusted to reflect additional fuel costs in the cases of high demand and modified system. The resulting TOD rate components are presented in Table 3.3. On-peak hours include 8 am to 8 pm Monday to Friday while off-peak hours make up the rest. Summer months include July to October and winter months November to June.

The demand response parameters for the medium and low response scenarios are given in Tables B.1 and B.2 in Appendix B.

The cross-elasticities of substitution presented in Tables B.1 and B.2 were not derived by rigorous statistical estimation due to the limited resources available. They were specified using judgment and qualitative information obtained in a limited number of interviews with selected customers in the WEPCO service territory. The overall structure represented by the values specified implies the following:

- It is easiest to reschedule electricity consumption between hours in the same shift.
- It is hardest to reschedule electricity consumption from the day shift to either the night or evening shift because of employment constraints.
- It is easier to reschedule electricity consumption from the night or evening shifts to the day shift than it is to reschedule from the evening to the night shift or vice versa.

The basic assumption underlying the above structure is that labor rather

Table 3.3

TIME-OF-DAY RATES FOR INDUSTRIAL CUSTOMERS

WEPCO 1980

Time	Demand	System	Energy Charge (cents/kWh)	Demand Charge Summer $/KW/month	Demand Charge Winter $/KW/month
on-peak	low	WEPCO	3.3o	4.68KW/month	3.60KW/month
on-peak	high	WEPCO	3.77	4.68	3.60
on-peak	low	Modified	5.24	4.68	3.60
on-peak	high	Modified	5.61	4.68	3.60
off-peak	low	WEPCO	1.65	-	-
off-peak	high	WEPCO	1.84	-	-
off-peak	low	Modified	3.09	-	-
off-peak	high	Modified	3.34	-	-

than capacity constraints are more important in determining demand rescheduling. This assumption as well as the magnitudes used should be carefully investigated in a second phase to the present study.

Only the cross-elasticities are specified by the response algorithm parameter inputs. The own elasticities are then calculated to satisfy the "constant consumption" and "constant expenditure" share assumptions characterizing the demand response and consumer surplus estimation algorithms, respectively. The ranges of price elasticities of demand implied by the input parameters and the above assumptions are also reported in the Tables B.1 and B.2 in Appendix B as are the characteristics of the generating systems used in the simulation (Tables B.3 and B.4).

In summary, the modeling structure developed for this effort combined an existing utility simulation model with a price responsive demand algorithm based on hourly spot prices. The structure allwoed for price to refect the marginal system operating cost or system lambda under all conditions in which the capacity minus spinning reserves exceed demand. When this condition was not met a quality of supply premium was added which reflected the cost of increasing capacity. The analysis was structured to evaluate only the responsiveness of the industrial component of the load. The modeling structure itself, however, is not limited to one component of the load but could be adapted to handle price responsiveness of individual classes of customers. It should be pointed out, however, that computer limitations of the simulation model used would effectively restrict the handling of more than two customer classes. In addition convergence of supply and demand at a spot price would not necessarily be guaranteed within the modeling structure if different response algorithms were used for the customer classes.

The chapter which follows presents the limited case study material for Wisconsin.

CHAPTER 4

WISCONSIN CASE STUDY RESULTS

The simulation model described in Chapter 3 was used to analyse the benefits of a one hour spot price rate for industrial customers in a prototype Wisconsin utility. Two sets of scenarios were developed for analysis. The first set were for the prototype utility given its current generating stock assuming first the 1980 demand structure and then a demand 10 percent greater than the 1980 demand but with no change in generating capacity. In each case the effect of both a high and a low response on the part of customers was evaluated. The second scenario developed looked at the prototype Wisconsin utility but substituted oil fired plants for specific of the coal fired units. (See Appendix B for plant data.) This substitution was carried out to evaluate the potential savings both in operating costs and in capacity that could be achieved if the test utility were less well optimized to today's utility fuel costs. The second or modified scenarios are more typical of the capacity and fuel mix for the New England and California utilities where there is considerably more dependence on oil. Table 4.1 summarizes the scenarios evaluated in this analysis.

All simulations included two production cost iterations for initial and modified demand. The simulations marked with a double x included a second pass through the demand response and consumer surplus algorithms yielding an improved estimate of the industrial customer electricity bill and consumer surplus. The simulation algorithm was not carried out to convergence because of the computational burden involved. Thus the reported benefits are conservative estimates that bound the convergence

Table 4.1

SPECIFICATION COMBINATIONS SIMULATED

System Demand/ Response	WEPCO Low Demand	WEPCO High Demand	MODIFIED Low Demand	MODIFIED High Demand
Low Response	x	x		
High Response	xx	xx	x	xx

estimates from below. Convergence problems were more severe with the high demand scenarios where the industrial electricity bill was particularly sensitive to a second pass through the demand response algorithm. For each scenario simulated, Tables 4.3 to 4.4 present the industrial customer electricity bill savings, and consumer surplus realized under spot pricing compared to the present practice of time-of-day (TOD) rates. The relative reliability of overall service by the utility defined as the ratio of the loss of load probability under TOD rates to the loss of load probability under spot pricing is reported. The reduction in variable generating costs due to spot pricing is also reported. Finally, Table 4.5 reports the net revenue of selected generating units obtained as the difference between the social value of electricity supplied and variable operating costs. The social value of electricity is obtained by weighing generation by the spot price. This net revenue is then capitalized after subtracting fixed O+M costs by assuming a 20-year service life and a 7 percent real (over and above inflation) rate of return. The capitalized values indicate whether the generating system is over or under invested in a particular generating technology. As discussed in Chapter 2 the optimal generating mix under spot pricing is such that net revenues as defined above are equal to fixed O+M and capital servicing costs.

Table 4.2 presents total variable generating costs, energy generated, loss of load hours (LOLH), and the industrial customer electricity bill under TOD prices and the various demand response and generating system specifications.

The results presented in Tables 4.2 to 4.5 support the following key points:

- Short-term fuel savings the utility may realize due to industrial customer spot pricing are of the order of 1 percent of the industrial electricity bill if the assumption of constant daily industrial electricity consumption is valid. Given that this assumption is rather conservative, the 1 percent figure should be interpreted as a lower bound with 5 percent an upper bound if the non-industrial demand profiles remain unchanged.
- Spot pricing implementation may result in substantial long-term reductions in utility capital costs by reducing the need for maintaining high reserve margins. Under the most conservative assumption of demand response, industrial customer spot pricing maintains the same reliability level for a 5 percent uniform increase in total demand. This is equivalent to allowing a 5 percent decrease in reserve margin without deterioration in service reliability.
- Long-term efficiency gains will be made possible by spot pricing. The current WEPCO generation mix would be underinvested in base loaded nuclear plants and overinvested in peaking units if spot pricing were to be widely implemented. A restructuring of the utility's generation mix coupled with a reduction in the reserve margin maintained would be desirable

Table 4.2

PERFORMANCE UNDER TOD PRICES

	WEPCO		MODIFIED	
	Low Demand	High Demand	Low Demand	High Demand
Variable costs $\$ \times 10^3$	230,667	251,026	459,210	494,687
Energy gen.	18176.3 GWH	19081.3 GWH	18173.6 GWH	19074.6 GWH
LOLH	18.0	40.9	35.25	88.5
Industrial bill $\$ \times 10^3$	163,000	187,900	246,800	275,000

Table 4.3

PERFORMANCE UNDER SPOT PRICES WEPCO SYSTEM

	Low Demand		High Demand	
	Low Response	Med. Response	Low Response	Med. Response
Industrial bill savings, $\$ \times 10^3$	9,627	35,140	*	*
Percent of bill	5.8 pct.	21 pct.	*	4 pct.
Consumer surplus, $\$ \times 10^3$	95,600	98,460	92,800	101,500
Percent of bill	58	60	49	54
Relative Reliability	1.87	2.18	1.06	1.22
Fuel savings $\$ \times 10^3$	928	1,128	1,993	2,375
Percent of bill	0.6	0.7	1.1	1.3

*Not reported because second pass through demand response algorithm was not obtained.

Table 4.4

PERFORMANCE UNDER SPOT PRICES MODIFIED SYSTEM

	Demand Low Response Medium	Demand High Response Medium
Industrial bill savings, $\$ \times 10^3$	-47,250	-71,140
Percent of bill	-19	-16
Consumer surplus, $\$ \times 10^3$	72,740	67,400
Percent of bill	29	25
Relative eliability	2.05	0.99
Fuel savings, $\$ \times 10^3$	1,800	3,037
Percent of bill	0.8	1.1

Table 4.5

PLANT AVERAGE VARIABLE COST (AVC), NET REVENUE (NR) AND CAPITAL NET REVENUES (CNR)*

		WEPCO		MODIFIED	
Plant		Low Demand	High Demand	Low Demand	High Demand
PB2	AVC	5 mills/kWh	5 mills/kWh	5 mills/kWh	5 mills/kWh
	NR	90.5 $/KW	116 $/KW	211 $/KW	235 $/KW
	CNR	982 $/KW	1144 "	2142 "	2394 "
OC8	AVC	14.5 mills/kWh	14.5 mills/kWh	32.5 mills/kWh	32.5 mills/kWh
	NR	31 $/KW	48 $/KW	30.5 $/KW	46.7 $/KW
	CNR	251 "	435 "	247 "	417 "
PW1	AVC	19.8 mills/kWh	19.8 mills/kWh	43.5 mills/kWh	43.5 mills/kWh
	NR	26.6 $/KW	44.3 $/KW	14.6 $/KW	24.7 $/KW
	CNR	122 "	307.6 "	--	102.0 "
OCCT	AVC	50 mills/kWh	50 mills/kWh	50 mills/kWh	50 mills/kWh
	NR	6 $/KW	11 $/KW	6.4 $/KW	11.3 $/KW
	CNR	42 "	94 "	46 "	98 "

*NR is the revenue over and above variable operating costs. CNR is obtained by capitalizing the difference between NR and fixed O and M costs.

under spot pricing and would result in substantial overall cost of generation reductions. The need for reoptimizing the generation mix is much more acute in the modified generating system simulations. In such a system, the base-loaded generators would realize excess profits under spot pricing. The small net revenues of peaking units, although indicative of overinvestment, should be interpreted with caution since the simplified pricing algorithm used in this simulation does not account for credits and charges related to meeting spinning reserve requirements.

- Comparison of the actual 1980 industrial electricity bill to the value of industrial electricity consumption weighted by spot price implies an insignificant overall subsidy between customers and the utility. Of course, individual customer analysis may indicate positive or negative cross-subsidies among customers, but the overall cross subsidy averaged over all customers is insignificantly different from zero. A 5 percent discrepancy between the actual bill and the value of electricity is observed which is well within the accuracy of the simplified pricing algorithm used. Inclusion of the loss and transmission and distribution components will more than likely account for a 5 percent discrepancy. The same conclusion, however, cannot be sustained for the high demand scenario. In the high demand scenario, the value of industrial demand obtained from the actual 1980 profile (no rescheduling) is significantly larger than the bill. This comes as no surprise, given that no additional generation was added and demand charges were unchanged despite the 5 percent increase in overall demand. Finally, even accounting for customer response does not seem to cause substantial redistritibutive concerns, especially if the eventual decrease in reserve margin is considered.

- Quite substantial customer benefits are possible through spot price implementation. An upper bound of realizable customer surplus consistent with a constant expenditure share hypothesis is of the order of 50 percent of the 1980 industrial customer bill. This surplus is realizable because of the additional flexibility and degrees of freedom made available to industrial consumers under spot pricing that allows them to choose their electricity consumption patterns so as to minimize the overall cost of electricity and other factor inputs. The utility benefits in terms of variable cost savings, reserve margin reductions, improvements in load factors, and the optimal generation mix have not been simulated for the more optimistic response assumption embedded in the estimation of an upper bound in consumer surplus gains. It should be noted that utility benefits will be higher than those presented above if the optimistic response assumption holds.
- The prospects for consumer rate reduction with spot pricing adjusted to meet utility revenue requirements are notable. In the short run, rate reductions would be limited to a few percentage points reflecting fuel savings. In the medium and long runs, however, higher savings due to lower reserve margin requirements and efficiency gains resulting from the reoptimization of the generation mix will also be realized and

passed on to consumers. These savings will benefit all consumers whether under TOD or spot pricing through lower demand generating costs and a lower rate base.

- Finally, spot price implementation will benefit the capital markets. It may keep some utilities out of the nation's capital market by easing their investment requirements. Some utilities on the other hand may need to radically alter their generation mix and resort to substantial borrowing. The resulting efficiency gains, however, will render such investments productive, and hence make them easier to fund in the capital market.
- The need for accurate demand response parameter estimates is of paramount importance. The benefits evaluated by the simulation algorithm presented in this chapter are only indicative and should be interpreted as orders of magnitude rather than as reliable absolute value estimates. A good deal of empirical investigation and actual experimentation will be necessary before any actual widespread spot pricing implementation takes place. From a preliminary evaluation point of view, however, the present study has clearly provided evidence in support of a high benefit of spot pricing hypothesis.

CHAPTER 5

BILL IMPACT ANALYSIS*

5.1 Introduction

Customer bill impact analyses were done at both the aggregate class and the individual customer levels to provide information for reconciling current class revenue requirements with the class revenue that would be generated with spot pricing rates. The two major concerns in reconciling revenues were that the utility remain financially whole and that no individual customer should experience an increase in charges that would be unfairly extreme. By construct it was expected that the proxy spot pricing rates without a capacity surcharge would generate revenues below current rate revenue levels. This would mean that all or part of the class's bills would need to be increased to avoid interclass subsidy. The aggregate analyses showed the revenue reconciliation problem to be minimal at the class level. However, more work must be done with the individual customer data to allow specific recommendations to be made with regard to bill impacts for individuals.

5.2 Aggregate Bill Impact Analysis with No Adjustments

Summary of Results

The initial bill impact analysis compared the actual 1980 annual class revenue level with the annual revenue level that would have been earned if proxy system lambda rates were applied to actual 1980 customer consumption levels. No adjustment was made for any price response and no rationing surcharge was included with the proxy system lambda rate. The

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*Chapter 5 was largely the responsibility of Ms. Leigh Riddick whose efforts in data handling and analysis are gratefully acknowledged.

actual 1980 class revenue level was based on the actual bills paid by the customers in the class.

When adjusted for marginal line losses the proxy revenues fell short of actual revenues by only 6.6 percent. The actual numbers were:

Historical Revenue Estimate	$166,629,108
Proxy Revenue Estimate	$155,627,284

It is noteworthy that this shortfall in revenue of $11,001,824 could be covered by a fixed monthly charge that would be less than the minimum monthly charge in the General Primary tariff during 1980.* The annual fixed charges necessary to reconcile revenues would be $20,488 per customer and the minimum charges in the General Primary tariff was almost $25,000 per customer.

Data

The consumption data were hourly KW demand for 1980 for the 538 general primary time-of-use customers of WEPCO in Wisconsin. These customers were all billed on the basis of the WEPCO tariff CP1 during 1980. To have qualified as a member of this class, a customer must have contracted for three-phase, 60-Hertz power service at approximatey 3,810 volts or higher for periods of at least one year. These customers faced an average minimum monthly bill of nearly $2000 at the beginning of 1980. The minimum charge was increased when revised tariffs were implemented during 1980. The peak period was 8 am through 8 pm, Central Standard Time, Monday through Friday, excluding legal holidays. All other hours were off-peak hours.

The data were provided by WEPCO on computer tape. Our initial

*Current and past tariffs are on file at the Wisconsin Public Service Commission.

reading of the data suggested two potential problems: (1) Missing observations, and (2) Observations showing zero readings. These two characteristics of the data set merited notice because without a complete and accurate data set by hour, the hourly load modeling for use in analyzing cost changes and bill impacts would not be complete or accurate. Two steps were taken in the initial data analysis to determine the degree of severeity of these potential problems. First counts of both the missing and zero readings, as well as their locations, were obtained. Customers with unusual patterns of zero readings were flagged as candidates for future individual graphical analyses and a review of the error codes on the WEPCO tapes. The graphical analyses and the error codes reviewed supported the validity of the zero readings; most seemed to be due to normal usage patterns (e.g., weekends contained zeroes) and they were often associated with multiple meter* customers.

Second, the missing observations were replaced with the group's average customer demand for that hour via the following algorithm:

$$\text{Average Demand}_i = \frac{\sum_{\alpha} D_i^{\alpha} I_i^{\alpha}}{\sum_{\alpha} I_i^{\alpha}}$$

where: i indicate the hour, from 1 to 8764 (1980 = Leap Year)

α indicates the customer, from 1 to 538

D_i^{α} is demand in hour i for customer α

I_i^{α} is the "switch" in hour i for customer α which indicates presence of an observation

---

*There were 40 multiple meter sites attributable to 32 customers.

0: no observation present

1: observation present.

This procedure implies that missing observations are statistically random across customer class at any hour. After the replacement was completed, total annual kWh class sales were only five percent greater than sales recorded by the utility. An adjustment is made below to the company revenue figures to account for this difference. This difference arose from the fact that VEPCO does not use a standard algorithm to estimate missing billing records. For this reason we could not duplicate its replacement procedure exactly. The precise KwH figures were:

VEPCO Sales*	4,779,949,091
General Primary Customer Tariff Records	-5,033,910,208
Difference	(253,971,117)

It should be noted that 243 (of 538) customers had complete records. Of those with incomplete records, the number of missing hourly observations varied from 24 hours (1 day) to 7560 hours (360 days).** However, no single hour was missing more than 67 observations (12 percent) or less than 28 observations (4 percent).

The sysem cost data used were hourly system marginal cost as calculated during 1980 by the VEPCO system control center. For each hour marginal cost was calculated as follows:

1. Sum the actual unit generations on system for the hour.
2. Economically dispatch the sum from (1) among units with the unit high limits being equal to the actual capabilities for the hour and the unit low limits being the predefined minimum generations for the unit.

*Source: Letter from P. Holte, VEPCO, dated July 27, 1981.

**If a portion of a day's readings were unavailable, the entire day was scratched from VEPCO's records.

3. Add purchased MW into total from (1).

4. Subtract one MW from the sum in (3).

5. Economically dispatch the sum from (4) among units and purchases with the high limits of the units being the dispatched generations from (2).

6. The difference in total cost between the dispatches in (2) and (5) is the marginal cost.

There were twenty-three missing days of information* in the system cost data. The missing hourly observations were filled in with a simple interpolation of the observations on the applicable day before and the day after the missing day (e.g., a missing Monday was filled in with an interpolation between the previous Friday and the following Tuesday).

The historical revenue figure, which was based on WEPCO's monthly sales analyses, was obtained from the company.* The amount of the actual bills paid by General Primary customers, including fuel adjustment charges, was used. The energy component of this amount was adjusted upwards by the percentage difference in spot price KwH sales estimates mentioned above, resulting in the following figures:

Original revenue	$160,852,195
Energy revenue adjustment	5,776,913
TOTAL GENERAL PRIMARY REVENUE	$166,629,108

Spot price revenues were computed by the following algorithm:

Let

x_{ij} = load of jth customer at ith hour as defined above

MC_i = system marginal cost at ith hour as defined above

where

*No observations were missing unless the entire day's observations were missing.

$i = 1$ to 8764 (hours in 1980)

$j = 1$ to 538 (number of customers),

then

$$\text{Spot Price Revenues} = \sum_j R_j$$

where

$$R_j = \sum_i X_{ij} MC_i$$

5.3 Individual Customer Bill Impact Analyses

Summary of Results

Three simulated spot price bills were calculated for comparison with the actual 1980 bills of a subset of the General Primary customers. The three scenarios simulated were the proxy system lambda bills, the spot price high demand bills, and the spot price low demand bills. The first scenario is described above in the aggregate analysis. The remaining two are described in more detail below in this chapter and in the preceding discussion of Chapter 4.

The ten customers chosen for individual analyses were selected on the basis of their usage patterns to provide information across a wide range of customer types. Table 5.1 is a summary list of those customers and their characteristics. The bills of these ten customers were simulated using the proxy system lambda as described above and simulated spot prices from the NEPCO low and high demand scenarios described in Chapter 3. Comparison of the simulated bills showed a fair amount of variation of the average price per kWh consumed among customers. The two chosen randomly had averages close to each other and to the total

Table 5.1

STATISTICS ON INDIVIDUAL CUSTOMERS CHOSEN FOR BILL ANALYSIS

Customer Choice Criteria*	SIC Code	kWh Annual Sales 1980	KW NCD Peak	KW CD Peak	NCD L.F.	CD L.F.
Largest CD, kWh	3519	116,356,939	23,210	19,642	0.571	0.674
Largest NCD	3531	21,606,186	36,660	3,889	0.067	0.632
Largest NCD L.F.	3221	23,887,268	3,000	2,740	0.906	0.992
Medium NCD L.F.	3469	44,446,681	9,720	7,870	0.521	0.643
Lowest NCD L.F.	3621	13,003,532	14,870	2,585	0.100	0.573
Largest CD L.F.	3312	28,654,708	6,890	3,307	0.473	0.986
Medium CD L.F.	2038	4,114,434	1,010	992	0.464	0.472
Lowest CD L.F.	8211	825,300	500	477	0.188	0.197
Random	3321	7,831,488	3,190	1,639	0.279	0.544
Random	8211	1,557,546	510	187	0.348	0.948

*CD: Coincident demand.

NCD: Non-coincident demand.

LF: Load factor.

average. Some customers exhibited higher bills under spot pricing and some lower in comparison to their actual 1980 yearly bills. This indicates that the present TOD rate structure is subject to substantial cross-subsidies among customers in the General Primary tariff class. Of course, the customer demand profiles used were the observed ones and hence unadjusted for customer response. Hence, the individual customer bill reconciliation problem may be ameliorated under spot pricing. No individual responses were simulated since they are customer-specific and the actual characteristics of the selected customers were unknown.

5.4 Interpretations and Recommendations

Individual bill analysis is unsuitable for drawing specific recommendations on revenue reconciliation. The main problem is that the algorithm used to replace missing observations for individual customer's hourly readings resulted in some biases. The procedure is entirely appropriate for the aggregate analysis, but it results in estimates that are too high or low for individual customers who lie very far from the mean consumption level for the group.

It is fairly straightforward to identify what needs to be done to correct these problems in future work. The replacement procedure for individual missing observations would need to be done on an individual basis. Rather than substituting class averages, some average or interpolation (similar to what was done for missing system data) would need to be done for each customer.

In summary, the aggregate analyses suggest that class revenue under spot pricing will not vary from historical revenue levels by a large amount. This is encouraging because it greatly simplifies the revenue reconciliation problem raised by current embedded revenue regulatory procedures. However, more work is needed to specifically address individual customer revenue reconciliation problems and the cross-subsidies among customers in the same class.

CHAPTER 6

CONCLUSIONS AND RECOMMENDATIONS

Optimal or spot pricing was investigated in this report. Optimal spot pricing was shown to be desirable because it improves the efficiency of the electric power system. It can significantly improve the well being of the utility system (generators and customers) through lower costs, fewer blackouts and brownouts, easier integration of customer owned generation and other advantages. It can give higher profits for both the utility and its customers. Examples of the impacts of optimal spot pricing include:

- Reducion of oil consumed in generation by raising prices explicitly whenever oil is being used.
- Removal or reduction of the need for rotating blackouts to handle emergency generation shortage situations, by using prices to give an automatic socially efficient rationing system.
- Enhancement of and integration of wind, solar, and customer-owned cogeneration into the grid by providing an energy marketplace which values energy at its "true" value. Variable charges, backup charges, and capacity credits are not needed.

Considerable transactions and communications costs may be associated with spot pricing implementation. Although recent advances in microelectronic and communications technology have rendered these costs small relative to potential benefits for responsive or larger customers, it may be preferable to use simpler or predetermined prices for some customers. This report developed such optimal predetermined prices and showed their relationship to optimal spot prices.

A case study was carried out with WEPCO data which simulated the impacts of spot pricing industrial electricity consumption under various assumptions on demand response, available capacity reserve margin and generation fuel costs. The case study results point toward the following conclusions.

- The utility may realize short-term fuel savings of the order of 1 to 5 percent of the aggregate revenues received presently from industrial consumers.
- Spot pricing of industrial consumers may result in a sizeable reduction in reserve electricity margins by an amount equal to at least 5 percent of present total yearly peak demand.
- Long-term efficiency gains will be possible through spot pricing via reoptimization of the generating technology mix. Improvement of overall load factors under spot pricing renders the present capacity mix overinvested in peak and underinvested in base generation. The spinning reserve value of peaking units should be accounted for before reaching any firm conclusions on this matter.
- Comparison of actual aggregate revenues under the present Time of Day rate structure to simulated revenues under spot pricing does not indicate substantial subsidies and hence a need for major revenue reconciliation action. However, individual customer analysis shows substantial cross-subsidies among individual customers.
- Substantial consumer benefits in the form of sizeable consumer surplus increases are possible through spot pricing. An upper bound estimate of these gains obtained, indicated a possible gain of up to 50 percent of the current customer bill.
- Long-term benefits for consumers, over and above short-term improvements are likely as a result of reduced capacity reserve

margin requirements and long-term efficiency improvements through generation mix reoptimization.

- Beneficial impacts on the capital market are also possible under spot pricing which will provide the opportunity for productive improvement in efficiency and hence make capital financing easier.
- A fair amount of uncertainty in the response parameters has resulted in benefit estimates being reliable only as orders of magnitude. A good deal of empirical investigation is needed to yield more reliable response parameter estimates which can be then used to obtain better and more accurate potential benefit values.

In summary, the present study has provided evidence in support of high potential benefits of spot pricing.

RECOMMENDATIONS

It is recommended that:

o Wisconsin proceed to the next step in the design of spot pricing experiments and spot pricing rates for large industrial customers. This analysis and other work under way indicates that the potential for societal savings and for customer benefit from participation in spot pricing rates are such that experiments should begin.

o The State of Wisconsin adopt a framework of an instantaneous spot price in which to analyze and evaluate alternative electric services offered to all levels of customers. The concepts of the instantaneous spot price should be expanded to commercial and residential customers at least in so much as the rate design, cycle length, and the ability to rationalize between utility rates can be brought into focus.

- The concept of an instantaneous spot price should be used to rationalize all existing utility rates and load management programs.
- The utilities should assume the lead in the design and marketing of a range of internally consistent services to their customers which will focus on the needs of their customers in terms of cost savings, and as a result, using the basics of spot pricing benefit to the utility. These benefits can be seen in terms of overall cost savings, in terms of the energy requirements of the individual customers and in terms of the reliability requirements of the individual customers.
- A spot price experiment focussed on large consumers should be designed within the State of Wisconsin. This should take four major issues into consideration.
  - Customers should be identified who are on time of use rates (all current large industrial customer). Customers should be identified who currently have energy management computers or have the ability to respond with human schedulers to changes in energy prices. Customers should be chosen who have the ability either to store or reschedule energy use. This would focus attention on industrial gas, ferrous and non-ferrous scrap metals systems using electric arc furnaces and metal scrapping activities. Finally, customers should be identified on the basis of the price cycles that they require in order to be able to respond to spot pricing.

- Utility implementation. Utilities should work with their own system operators to develop simple means of predicting spot prices that would be in the medium to long-run automatic within the utility. In addition they should work to develop simple means for signaling prices to customers and for evaluating response to those price signals. The utilities should thoroughly evaluate the hardware requirements for spot pricing experiments and for spot pricing implementation based on the generic requirements for analysis of individual customer loads, for communication with the customer and for the customers response to spot pricing signals.
- Regulatory actions. The regulatory structure should explore the implications of using existing time of use rates for spot pricing experiments through adaptation of, for instance, the current fuel adjustment clause. It is anticipated that existing rate structures will allow for sufficient flexibility to move forward with experiments in spot pricing prior to the time at which new, spot rates can be set and agreed upon in the state. In addition, the utility should encourage the development of alternative rates for all customer classes which can take advantage of the concepts of the instantaneous spot price.
- Research requirements. Additional research and development is required in the area of customer response and monitoring customer consumption patterns looking for critical loads and looking for ways in which customers can respond to specific

lengths and levels of pricing for spot prices. In addition the impact on the utility of different types of spot pricing structures and cycles should be evaluated in greater detail particularly as additional experimental data becomes available.

CHAPTER 7

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APPENDIX A

A Synopsis of Wisconsin Electric Power Company

Wisconsin Electric Power Company (WEPCO) is an investor-owned public utility company operating in Wiconsin an the Upper Peninsula of Michigan. A fully-owned subsidiary, Wisconsin Natural Gas Company, distributes natural gas only within Wisconsin. WEPCO also owns and operates a steam district heating system in downtown Milwaukee. Approximately 75% of EPCO's revenues are derived from electricity sales, 24% from gas sales and 1% from steam sales.

In 1980, WEPCO sold 17,729 GWH and had a peak demand of 3,346 MW. The utility is presently summer peaking, but winter and summer peaks are forecast to be approximately equal by the mid-1980's, with the winter peak dominating after that time.

WEPCO has been a leading innovator in the fields of time-of-day rates and direct load control. All commercial and industrial customers with consumption greater than 30,000 KWH per month are billed on a TOD tariff. In addition, the larges 3,600 residential customers have been placed on a mandatory TOD rate, which will be extended as an option to an additional 10,000 customers.

An ambitious direct load control program for residential electric water heaters was begun in 1978. This control system uses a powerline carrier signal to remotely control the customers' loads. By December 1980, 40,000 control units had been installed, with the projected goal of 10,000. For participating in this program, the customer receives a monthly credit of $4.

WEPCO owns and operates a substantial number of generation facilities throughout its service territory. The majority of these are coal fired;

in 1980, these coal-fueled units generated 50% of the Company's needs. WEPCO also owns and operates two 495 MW nuclear units at Point Beach on Lake Michigan, which together generate about one-third of the company's output.

The company also has the capability of importing substantial amounts of energy through the strong interties it maintains with Commonwealth Edison to the South and its neighboring Wisconsin utilities: Wiconsin Power and Light (WPL), Wisconsin Public Service Corporation (WPS), and Madison Gas and Electric. (The service territories of WEPCO, WPS and WPL are contiguous and tend to be geographically interspersed.) During 1980, WEPCO purchased nearly 13% of their KWH needs from other utilities.

In 1980, construction was completed on the 580 MW Pleasant Prairie Unit I coal-fired cycling plant. The identical Unit 1 is scheduled to be completed in 1984. WEPCO has purchased a 100 MW share of a 400 MW coal unit from Wisconsin Power and Light that is also due to come on line in 1984. These capacity additions, combined with a 1.5-2.5% compound growth rate of peak demand, mean that the company will need no additional generation until the early 1990's.

WEPCO along with Madison Gas & Electric, Wisconsin Public Service Corporation, Wisconsin Power & Light and the Upper Peninsula Power Company form the basis of the Wisconsin Upper Michigan Systems (WUMS). WUMS is a regional planning group with the responsibility of coordinating the planning, operation, and maintenance of generation and transmission facilities for the member utilities. WUMS also represents these utilities in the planning and operation activities of the regional planning group MAIN. WEPCO does not belong to the form power pool consisting of the three other Wisconsin utility members of WUMS.

Residential and small commercial sales and industrial sales are approximately 30% and 25% respectively of total electric sales. The composition of these customer groups is similar to those of other Midwest utilities.

Industrial sales account for about 35% of WEPCO's total sales. The largest portion of these industrial sales are made in a few manufacturing categories. These are fabricated metal products and machinery, primary metal (foundries), paper, food, machinery, electrical machinery and equipment, and transportation equipment. These customers are grouped mainly in the Milwaukee metropolitan area, Racine, and Kenosha.

The interruptible service tariff offered by the utility to its industrial customers consists of a 60% reduction in the demand charge for firm service. As of January 1982, 4 large customers have placed 51 MW of connected load on this interruptible tariff.

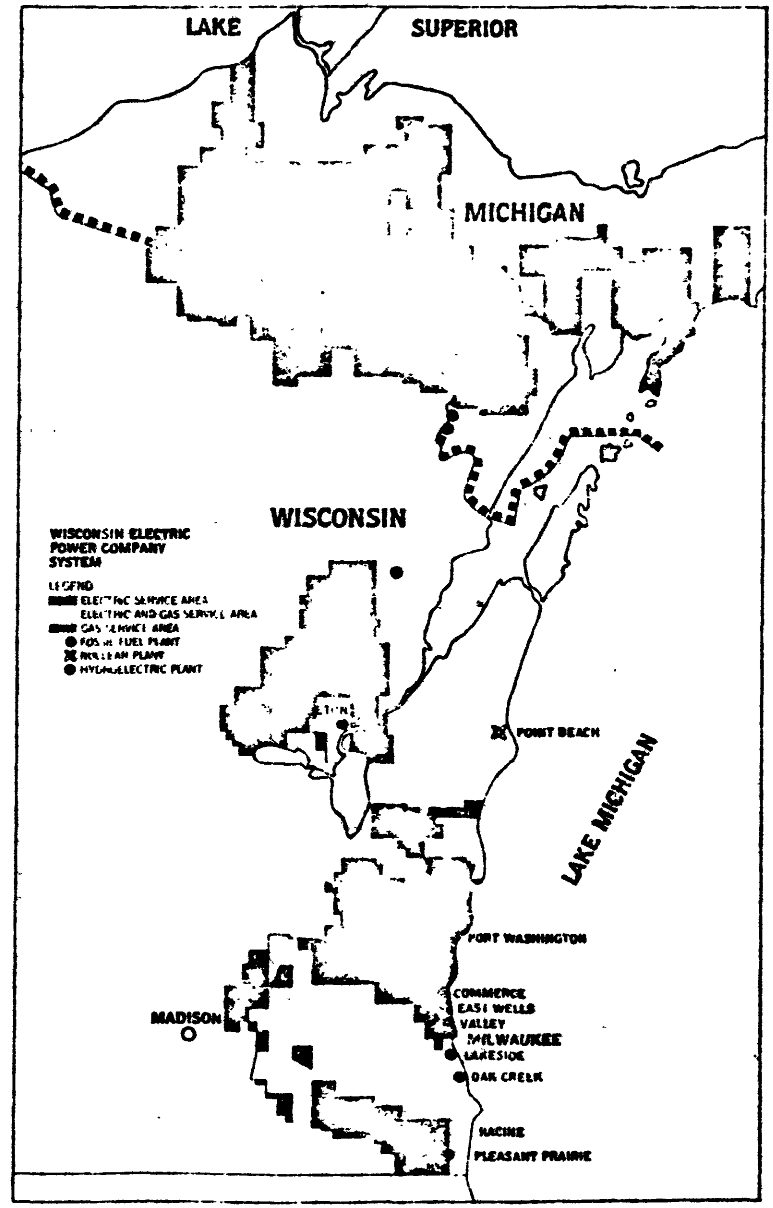
Unless otherwise noted, the tables on the following pages are from Wisconsin Electric's Statistical Report for the 10 years ending December 31, 1980.

SERVICE TERRITORY

Wisconsin Electric Power Co. is engaged principally in the generation, transmission, distribution and sale of electric energy in a territory consisting of approximately 12,600 square miles in southeastern Wisconsin, including the metropolitan Milwaukee area, the east central and northern portions of Wisconsin and the Upper Peninsula of Michigan. The operating area has an estimated population of over 2,000,000.

The company owns all the common stock of Wisconsin Natural Gas Co., which purchases natural gas from Michigan Wisconsin Pipe Line Co., then distributes and sells it in two service areas: west and south of Milwaukee, and in the Appleton area. The gas service territory which has an estimated population of over 800,000 is mainly within the electric service area of the company.

The executive offices of the company are located at 231 W. Michigan St., P.O. Box 2046, Milwaukee, WI 53201, telephone (414) 277-2345.



Capabilities of Electric Generating Plants—Year 1980

Plant	Location	County or River	Year of Instal. of Units	No. of Units	Capability January 1980 kW	Capability July 1980 kW
STEAM, FOSSIL FUEL:						
North Oak Creek	Oak Creek, Wis.	Milwaukee	1953-54	2		
			1955-57	2	444,000	431,000
South Oak Creek	Oak Creek, Wis.	Milwaukee	1960-61	2		
			1965	1		
			1967	1	1,070,000	1,057,000
Port Washington	Port Washington, Wis.	Ozaukee	1935-50	5	376,000	372,000
Lakeside	St. Francis, Wis.	Milwaukee	1920-21	2		
			1922-26	4		
			1926	1		
			1928-30	3		
			1928-30	2	261,000	261,000
Valley	Milwaukee, Wis.	Milwaukee	1968-69	2	254,000	268,000
Commerce	Milwaukee, Wis.	Milwaukee	1941	1	27,000	31,000
East Wells	Milwaukee, Wis.	Milwaukee	1939	1	12,000	10,000
Pleasant Prairie	Pleasant Prairie, Wis.	Kenosha	1980	1		580,000
Total Steam, Fossil Fuel					2,444,000	3,010,000
NUCLEAR:						
Point Beach	Two Creeks, Wis.	Manitowoc	1970	1	990,000	990,000
			1972	1		
COMBUSTION TURBINE:						
South Oak Creek	Oak Creek, Wis.	Milwaukee	1968	1	25,000	20,000
Port Washington	Port Washington, Wis.	Ozaukee	1969	1	23,000	18,000
Lakeside	St. Francis, Wis.	Milwaukee	1968	2	40,000	34,000
Point Beach	Two Creeks, Wis.	Manitowoc	1969	1	24,000	16,000
Germantown	Germantown, Wis	Washington	1978	4	264,000	208,000
Total Combustion Turbine					376,000	296,000
DIESEL:						
Valley	Milwaukee, Wis.	Milwaukee	1969	1	3,000	3,000
HYDRO:					Median	Median
Big Quinnesec Falls	Iron Mountain, Mich.	Menominee	1914	2		
			1949	2	16,000	15,000
Peavy Falls	Randville, Mich.	Michigamme	1943	2	16,000	15,000
Michigamme Falls	Iron County, Mich.	Michigamme	1953	2	8,800	8,800
White Rapids	Stephenson, Mich.	Menominee	1927	2		
			1927	1	7,200	8,000
Chalk Hill	Stephenson, Mich.	Menominee	1927	3	4,100	6,500
Kingsford	Kingsford, Mich	Menominee	1924	3	5,200	5,600
Twin Falls	Iron Mountain, Mich.	Menominee	1913	3		
			1916	2	5,600	5,100
Brule	Iron County, Mich.	Brule	1919	1		
			1919	1		
			1921	1	4,000	3,500
Pine	Florence, Wis.	Pine	1922	2	2,000	4,000
Hemlock Falls	Crystal Falls, Mich.	Michigamme	1953	1	2,500	2,400
Way	Crystal Falls, Mich.	Michigamme	1949	1	1,400	1,400
Appleton	Appleton, Wis.	Fox	1901	1		
			1916	2	1,200	1,100
Oconto Falls	Oconto Falls, Wis.	Oconto	1918	1		
			1921	1		
			1924	1	600	800
Sturgeon	Loretto, Mich.	Sturgeon	1923	1	800	800
Weyauwega	Weyauwega, Wis.	Waupaca	1930	1	200	200
Lower Paint	Crystal Falls, Mich.	Paint	1952	1	100	100
Total Hydro					75,700	78,300
Total System					[illegible]	[illegible]

WISCONSIN ELECTRIC POWER COMPANY SYSTEM

Electric Revenue and Expense Statistics

Year Ended December 31	1980
OPERATING INCOME ($000)	
OPERATING REVENUES	$761.232
OPERATING EXPENSES	
Fuel	213.467
Purchased power	63.203
Other operation expenses	
Production	43.414
Transmission and distribution	29.364
Customer accounts	15.095
Sales and customer service	3.127
Administrative and general	47.163
Maintenance	72.870
Taxes other than income taxes	31.399
Depreciation	
Straight line	60.992
Deferred income taxes	20.945
Federal income tax	(281)
Investment tax credit adjustments —Net	30.660
State income tax	2.096
Total Operating Expenses	633.514
OPERATING INCOME	$127.718
STATISTICS	
Average Number of Customers	802.090
Electric Energy Output (Million KWH)	
Net generation	
Fossil	9.983
Nuclear	6.066
Hydraulic	456
	16.505
Purchased power	2.403
	18.908
Company use, transmission losses and unaccounted for	(1.179)
Energy sold	17.729
Fuel Cost per Net Generated KWH	
Fossil fuel	1.85¢
Nuclear fuel	.48¢
Total Production Cost per Net Generated KWH	
Fossil	2.49¢
Nuclear	.77¢
Hydraulic	.43¢
Maintenance Expense as Percent of Average Depreciable Plant	4.04%
Depreciation Expense (Straight Line) as Percent of Average Depreciable Plant	3.55%

APPENDIX B

The "WEPCO" system without 1980 economy sales or purchases and a 410 MW inter-tie backup is used along with a "Modified" system which was obtained from the WEPCO system by modifying the fuel cost of coal-fired units to resemble oil-fired units and reducing intertie backup to 200 MW. Tables B.3 and B.4 give for each plant the forced outage rate (FOR), the maintenance requirements in weeks (MNTWKS), the variable and fixed operating and maintenance costs (O+M), the fuel cost (FUEL), the number of blocks (BLKS) making up each plant, and the total capacity (CAP).

Table B.1

MEDIUM RESPONSE CROSS-ELASTICITIES OF SUBSTITUTION (σ_{ij})

Hour of day j / Hour of day i	Night Shift 1, 2, ..., 7.8	Day Shift 9, ..., 20	Evening Shift 21, 22, ..., 24
1, 2, ..., 8	8.3	3.3	5.0
9, ..., 20	6.6	8.3	6.6
21, ..., 24	5.0	3.3	8.3

Note: a) Diagonal elements for i = j are not defined.

b) Price elasticities of demand ε_{ij} are defined as the percent change in demand i over the percent change in price j. They equal the product of σ_{ij} and expenditure share j for i ≠ j. They take values ranging as follows:

ε_{ij} = .0008 to .007 for i ≠ j

ε_{ii} = -.03 to -.08 in the demand response algorithm.

ε_{ii} = -.95 to -1.1 in the consumer surplus algorithm.

Table B.2

LOW RESPONSE CROSS-ELASTICITIES OF SUBSTITUION (σ_{ij})

Hour of day j / Hour of day i	Night Shift 1, 2, ..., 7.8	Day Shift 9, ..., 20	Evening Shift 21, 22, ..., 24
1, 2, ..., 8	2.7	1.1	1.6
9, ..., 20	2.2	2.7	2.2
21, ..., 24	1.6	1.1	2.7

Note: a) Diagonal elements for i = j are not defined.

b) Price elasticities of demand ε_{ij} are defined as the percent change in demand i over the percent change in price j. They are equal to the product of σ_{ij} and expenditure share j for i ≠ j. They take values ranging as follows:

ε_{ij} = .0002 to .002 for i ≠ j

ε_{ii} = -.01 to -.03 in the demand response algorithm.

ε_{ii} = -.98 to -1.05 in the consumer surplus algorithm.

Table B.3

PLANT DATA: WEPCO SYSTEM

	PLANT	FOR	MNT WKS	O&M VAR	O&M FIX	FUEL	# BLKS	CAP
1	PB2	.058	6	.44	7	44.0	3	498
2	PB1	.058	6	.44	7	44.0	3	498
3	OC8	.114	7	1.98	7	141.0	3	272
4	OC7	.114	7	1.98	7	141.0	3	281
5	OC6	.157	8	2.40	9	141.0	3	246
6	OC5	.157	8	2.40	9	141.0	3	246
7	OC4	.110	8	3.32	4	141.0	3	114
8	OC3	.110	8	3.32	4	141.0	3	114
9	OC2	.110	8	3.32	4	141.0	3	101
10	OC1	.110	8	3.32	4	141.0	3	101
11	PW5	.056	3	3.17	15	153.0	2	77
12	PW4	.056	3	3.17	15	153.0	2	80
13	PW3	.056	3	3.17	15	153.0	2	80
14	PW2	.056	3	3.17	15	153.0	2	80
15	PW1	.056	3	3.17	15	153.0	2	80
16	VAL2	.029	3	2.66	12	159.0	3	134
17	VAL1	.029	3	2.66	12	159.0	3	134
18	LSCT	0.000	0	2.30	14	281.0	2	30
19	COMM	.023	3	2.13	38	305.0	2	31
20	OCCT	.300	1	3.44	2	291.0	2	20
21	PWCT	.300	1	3.44	2	450.0	2	30
22	PBCT	.300	1	3.44	2	450.0	2	20
23	GMT1	.146	1	2.09	10	534.0	2	53
24	GMT2	.146	1	2.09	10	534.0	2	53
25	GMT3	.146	1	2.09	10	534.0	2	53
26	GMT4	.146	1	2.09	10	534.0	2	53
27	HYWE	.012	2	1.00	10	0.0	3	59
28	PP1	.123	6	1.43	7	185.0	3	480
29	HYPP	.012	2	1.00	10	0.0	1	19
30	EMG1	.100	0	83.00	0	0.0	3	100
31	EMG2	.100	0	83.00	0	0.0	3	100
32	EMG3	.100	0	83.00	0	0.0	3	100
33	VOLC	0.000	0	83.00	0	0.0	1	0
34	EMER	0.000	0	83.00	0	0.0	1	0

Table B.4

PLANT DATA: MODIFIED SYSTEM

	PLANT	FOR	MNT WKS	O&M VAR	O&M FIX	FUEL	# BLKS	CAP
1	PB2	.058	6	.44	7	44.0	3	498
2	PB1	.058	6	.44	7	44.0	3	498
3	OC8	.114	7	1.98	7	341.2	3	272
4	OC7	.114	7	1.98	7	341.2	3	281
5	OC6	.157	8	2.40	9	341.2	3	246
6	OC5	.157	8	2.40	9	341.2	3	246
7	OC4	.110	8	3.32	4	341.2	3	114
8	OC3	.110	8	3.32	4	341.2	3	114
9	OC2	.110	8	3.32	4	341.2	3	101
10	OC1	.110	8	3.32	4	341.2	3	101
11	PW5	.056	3	3.17	15	370.3	2	77
12	PW4	.056	3	3.17	15	370.3	2	80
13	PW3	.056	3	3.17	15	370.3	2	80
14	PW2	.056	3	3.17	15	370.3	2	80
15	PW1	.056	3	3.17	15	370.3	2	80
16	VAL2	.029	3	2.66	12	384.8	3	134
17	VAL1	.029	3	2.66	12	384.8	3	134
18	LSCT	0.000	0	2.30	14	281.0	2	30
19	COMM	.023	3	2.13	38	305.0	2	31
20	OCCT	.300	1	3.44	2	291.0	2	20
21	PWCT	.300	1	3.44	2	450.0	2	30
22	PBCT	.300	1	3.44	2	450.0	2	20
23	GMT1	.146	1	2.09	10	534.0	2	53
24	GMT2	.146	1	2.09	10	534.0	2	53
25	GMT3	.146	1	2.09	10	534.0	2	53
26	GMT4	.146	1	2.09	10	534.0	2	53
27	HYWE	.012	2	1.00	10	0.0	3	59
28	PP1	.123	6	1.43	7	447.7	3	480
29	HYPP	.012	2	1.00	10	0.0	1	19
30	EMG1	.100	0	83.00	0	0.0	3	100
31	EMG2	.100	0	83.00	0	0.0	3	100
32	EMG3	.100	0	83.00	0	0.0	3	100
33	VOLC	0.000	0	83.00	0	0.0	1	0
34	EMER	0.000	0	83.00	0	0.0	1	0

ENERGY LABORATORY

MASSACHUSETTS INSTITUTE
OF TECHNOLOGY

UTILITY SPOT PRICING STUDY: WISCONSIN
EXECUTIVE SUMMARY

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UTILITY SPOT PRICING STUDY: WISCONSIN

EXECUTIVE SUMMARY

The objective of the Utility Spot Pricing Study has been to evaluate, for a prototype Wisconsin electric utility, the potential benefits to both the customers and to the utility of utilizing a specific type of spot pricing for large industrial customers and to make recommendations for further experimentation and potential rate-making based upon spot pricing. In order to accomplish this objective a set of studies of both the utility and selected industrial customers was carried out and an existing simulation model expanded to allow for incorporation of customer response to changing electrical energy prices. The conclusions and recommendations presented in this summary build both upon the direct results of this effort and upon the results of parallel theoretical and application efforts carried out by the MIT Energy Laboratory.

Spot pricing of electric energy refers to the pricing of electricity to reflect the time varying costs of generation as seen by the utility. Today all utility rates are based either retrospectively or prospectively upon the the average time-varying operating and capital costs. These rates are generally the average utility costs measured over the cycle in which prices are updated--generally the period between rate cases or fuel adjustment updates.

Spot pricing utilizes as the starting point for all rate calculation the instantaneous marginal or operating cost of generation including transmission and distribution losses. At times of capacity shortage a charge reflecting the value of marginal electricity to customers is added (quality of supply) to create the instantaneous spot price.

The cost of generation may vary considerably from minute to minute, day to day and season to season. Spot pricing communicates the changing utility costs to the customer as changing electricity prices. The issue becomes one of choosing the appropriate frequency of price updates or the pricing cycle length by trading off cost-saving benefits against the costs of transactions between the utility and the customer. Price updates may be as frequent as every five minutes for highly automated industrial firms or as infrequent as once a year as is currently the case for most residential customers. The summary paragraphs which follow show the relationship between spot prices and the rates which are currently offered by utilities. As will be seen, all rates can be directly related to spot prices, they vary only in the time cycle between changes in price and in the number of price levels offered to the customer.

THE INSTANTANEOUS SPOT PRICE MARKETPLACE: Operates in the instantaneous time frame of the system dispatcher. In today's utility system the currency of the spot marketplace the cost of the most expensive unit or purchase* plus marginal T&D losses and a quality of supply premium.

Given an instantaneous spot price:

- o All rates can be related directly to the instantaneous spot price and to each other.
- o All customers with the same update cycle i.e. time between changes in prices, see the same price within a given level of service or voltage class.

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*This concept is called short-run marginal costing by economists and is related to the system lambda of economic dispatch.

- o A menu of different rates can be designed by varying cycle length and the detail of pricing period definitions.
- o The longer the cycle length and the less detailed the pricing period definition, the higher the cost of providing an equally reliable service.

The following represent a limited set of spot rates which span the range of both cycle length and today's utility rates. As was stated above, other rates may be described in a parallel manner.

5 MINUTE SPOT PRICE: The shortest time varying rate discussed. The pricing cycle is five minutes reflecting the expected cost of generation. The information utilized is analogous to the time frame used by the system dispatcher and incorporates system lambda or its equivalent as the marginal operating cost.

1 HOUR SPOT PRICE: Equivalent to the 5 minute spot price with recalculation on a 1 hour cycle. This study examined the benefits of a 1 hour spot price structure.

24 HOUR UPDATE SPOT PRICE: Hourly prices are set for the next 24 hours one day ahead based on the expected value of spot marketplace costs for each hour. This calculation is based on the same projections used in the predispatch done by today's system operators.

TIME OF USE AND FLAT RATES: These current utility rates could be spot price based if the rate is defined as the average expected value of the instantaneous spot price within the update cycle given prespecified time blocks that represent the pricing period definition.

INTERRUPTIBLE RATES AND DIRECT LOAD CONTROL: Current utility interruptible rates and direct load control such as water heater and air conditioner control can also be described through the structure of the spot marketplace by recognizing that these are services provided by the utility to its customers to control customer costs by guaranteeing that customer energy costs per KwH do not exceed the customers prespecified level of acceptance, i.e. that the customer never is charged more than an agreed upon cost for energy. The actual rate charged for this service would be based upon the expected value of energy generated below the prespecified interrupt cost level.

BENEFITS OF SPOT PRICING

Electric energy increasingly represents a significant cost for all consumers whether large industrial customers trying to maintain a relative market advantage, commercial customers supplying heating and cooling services to their tenants or their own facilities, or residential customers maintaining comfort and services within their own homes. This desire for cost control is also reflected in the utility's operations. Eroding stock values, difficulties in raising new capital and general tension between the utility, its customers and the regulatory bodies all find a common origin in higher costs of electric energy.

Spot pricing addresses the issues of cost control both for the customer and for the utility by developing sets of consistent price structures which allow customers to adjust their consumption patters to the actual time-varying costs. This is accomplished through the development of a set of consistent utility services to customers--a menu of service options with customer cost savings as their primary objective. The significance of basing this menu of options upon spot pricing is that customer savings result generally from demand response to spot pricing. A beneficial impact on overall utility costs is also realized. In the aggregate all customers, whether under spot pricing or not, benefit.

From the perspective of the customer, spot pricing can provide the basis for scheduling industrial processes to take advantage of lower energy costs during specific periods of a given day or during specific seasons of the year. Most of the spot price based rates proposed in this report provide sufficient information to the customer to allow the customer to choose to consume electricity on a when available at the "right price" basis. On a day-by-day basis, the knowledge that the price will be higher during certain midday hours will have the effect of encouraging high electric use operations to be rescheduled around that period so long as cost-effective excess capacity and/or product storage is available. At times when a facility is operating at full capacity and full production is valuable, a manager may continue to consume even at high spot price levels.

Smaller or non-energy-intensive customers are less likely to afford expensive communication and control equipment. In the near term most small customers will choose manual control of their energy use. However, concerned customers may wish to monitor hourly spot prices and program their consumption through home computers. The more likely pattern is for the customer to take advantage of the utility's assistance in controlling air conditioners or water heaters when the instantaneous spot price exceeds a prespecified level.

From the perspective of the utility, spot pricing brings a set of equally significant benefits. The most basic in the present environment is that the utility and customer make production and consumption decisions based on common cost information. The utility is providing or selling a service. It is not the consumer's adversary but rather a partner in an effort to reduce the customer's (and its own) costs. The utility can now provide essentially all of the electricity that any customer might wish--at a price.

Spot pricing simplifies the role of the regulatory commission. The intense adjudicatory proceedings surrounding the setting of individual rates are replaced by simpler and internally consistent processes of agreeing to the formulae by which spot prices for different time cycles and price period definitions are set. Once the formulae are agreed upon, the task of the commission is in monitoring and in revenue reconciliation.

Spot pricing improves customer-utility mutual understanding through increased customer options. It will always be difficult to quantify the value of improved understanding by the customer of the utility's problems and by the utility of the customers' desires. However, it is very real. Offering the customers an internally consistent, easy to understand menu of options based on spot prices is a major step in this direction.

Much of the cost control and increase in benefits resulting from implementation of a spot price based marketplace comes from the fact that it enables both the customers and the utility to better deal with the many uncertainties that exist. (Such as the future availability and cost of energy as determined by weather uncertainties, plant outages, possible oil embargoes or nuclear moratoriums, and the eventual potential development of new fuel sources and energy technologies.) A spot price based marketplace does not eliminate the risks associated with uncertainties. However, the uncertainties can be dealt with and the roles shared in a more effective fashion because of the natural feedback that results between the utility and the customers.

To summarize, no single action or approach can answer all of the problems of the utility industry. However, spot pricing moves the industry forward by bringing the customer in as a responder to the time varying costs of generation. Spot pricing exploits the revolution in microprocessing and in communications to establish a true marketplace where transaction cost and value are reflected in the buy/sell decision rather than the regulatory proceedings or special legislation.

PROJECT OBJECTIVES

The primary objective of the Utility Spot Pricing Study for Wisconsin was to evaluate the benefits of spot pricing to industrial customers and a prototype utility in Wisconsin. In order to accomplish this, the project had the following set of sub-objectives.

- To review the background in theory and literature that has been developed for spot pricing.
- To develop and implement a method of benefit estimation for a prototype Wisconsin utility.
- To carry out a survey of large customers to evaluate their potential response to spot pricing.
- To develop and implement a methodology for incorporating customer price response into a utility simulation model.

- o To evaluate the utility/customer/societal benefits from spot pricing systems.
- o To evaluate the potential impact on the individual customers bills.
- o To make a set of recommendations for proceding to develop spot pricing experiments in Wisconsin.
- o To broaden the analysis by evaluating alternative utility capital stocks based more on oil than on coal and nuclear as is the case in Wisconsin.
- o To review the availability of hardware for spot pricing experiments.

These objectives were then aligned to create a research plan that allowed for a smooth flow of information from the sub-objectives to the final analysis of the benefits of spot pricing for Wisconsin.

CONCLUSIONS

The Wisconsin study netted a set of significant conclusions that are here grouped into two categories. The first category is that of general conclusions which are applicable, we believe, to any utility system regardless of its generating stock or its customer characteristics. It should be pointed out, however, that the benefits are greatest under circumstances in which the utility generating stock is in short supply and in which the utility must operate with oil or other expensive generating fuels on the margin. In addition, the benefits are the greatest under circumstances in which customers have the ability to either defer load or to store either energy or final product. The responsiveness of customers is a major determinant of the total benefit to customers, to utility and to society as a whole generated by a spot pricing system.

The general conclusions which were drawn from this study and from other expérience of the research team are the following:

- o Under spot pricing the joint benefits to the utility and to the customer can be clearly seen in the increase in what the economist refers to as consumer surplus.
- o There is a reduction in oil consumption by the utility when prices reflect marginal fuel costs. By the same token there is an increase in consumption of lower cost fuels such as coal.
- o With spot pricing there is an increase in system reliability. This increase in system reliability is brought about by the responsiveness of customers to increases in utility generating costs. As will be seen in the specific conclusions, this increase in reliability may be significant.
- o There is a general enhancement in the ability of distributed energy technologies such as cogenerators and/or small generators to integrate into the utility system when spot pricing is the method of payment for electricity generated. The value of electricity to the utility from a cogenerator is most easiliy measured using the system spot price as defined in the introduction.

The general conclusions are valid for most, if not all, electric generation systems. Spot pricing acts to save customers additional funds through encouragement of greater efficiency in timing and amount of electric energy used. In addition it increases the reliability of the system through the responsiveness of customers thereby sharing or cooperating with the utility in the provision of that reliability. Finally, the ability to integrate new energy technologies into the grid under the terms of the Public Utilities Regulatory Policy Act (PL 95-617) is greatly enhanced.

From the Wisconsin study there are a set of specific conclusions that can be drawn. It should be emphasized that the conclusions are based upon a simulation analysis of a prototype Wisconsin utility. The prototype utility had both coal and oil on the margin during the test year. The utility has considerable reserve capacity on line. Reliability analyses were carried out by increasing demand while holding capital stock fixed. For analytic ease it was assumed that there were no interconnections. Given these caveats the conclusions which were drawn are the following:

- Given the implementation of spot pricing for industrial customers the utility will be able to save between 1 and 5 percent of its total fuel costs. This reflects a basic shift away from high cost fuels such as oil toward the lower cost fuels of coal and nuclear.
- Given the prototype system evaluated there is a potential of a reduction in reserve capacity of roughly 5 percent brought about by the increase in customer response to spot price.
- In the long term there is a possibility of a gain in the total efficiency of the utility system through a reoptimization of the utility capital stock. This is once again brought about by the responsiveness of customers toward variable marginal costs

thereby allowing the utility to reoptimize its capital stock toward increased base load plants and away from oil fired intermediate and peaking plants.

- Given the spot price structure chosen and the modeling techniques chosen, there appear to be only minimal issues associated with revenue reconciliation on the part of the utility and the regulatory commission. It must be emphasized that revenue reconciliation will always be an issue in a regulated utility structure under spot pricing as it is an issue under the current regulatory structure. The importance of the findings in this study is that the order of magnitude of the revenue reconciliation problem is not any greater than that faced by most regulators and utilities in today's marketplace.
- The final conclusion may be the most important from this study and that is that the total customer benefits possible from the adoption of a spot pricing structure could be as high as 50 percent. Once again these customer benefits depend on the ability of customers to readjust their loads to reflect changing electric prices. Such benefits are, under any circumstances, highly significant and require serious further consideration on the part of both the utility and the utility commission for implemention of spot pricing.

In summary, the major conclusions of the research project were that spot price based utility rates appear to hold considerable promise for overall savings. The potential customer benefits to participating in a spot pricing system are as high as 50 percent. In almost all instances the utility and customers as a group can benefit by increased cooperation and information flow between the utility and its customers using the currency of spot price. This results in far greater short term efficiencies represented by the utility savings of between 1 and 5 percent in fuel cost and the potential for long term gains in efficiency through reoptimization of the capital stock.

RESEARCH STRUCTURE

The research and modeling effort was divided into three major blocks; customer response analysis, utility impact analysis, and customer bill analysis.

Customer response analysis was carried out in parallel with the initial utility modeling activity and the utility impact analysis. A set of industrial facilities in the Wisconsin area were visited and plant operators and plant managers interviewed. This was a non-random, small sample of those customers that, *a priori*, appeared to have a potential for responding to variable prices. After detailed discussions with roughly ten industrial firms, the responses to the questions asked concerning energy use, energy storage and product storage were categorized into sets of actions which any individual facility might take. These sets of actions fell into two broad areas. The first area was that of rescheduling of load. Rescheduling was seen as first, a movement of process flows within a given labor shift. The second was seen as the possibility of moving specific high-energy processes from one shift to another where this did not interrupt the flow of plant processing. The second category was that of storage. Considerable effort was spent on evaluating the availability of both product storage, i.e., intermediate goods to be used in the final assembled product, and the storage of energy through, for instance, on-site generation and/or on-site thermal storage.

Having completed the plant visits and the categorization of plant responses, a set of small scale optimization models were carried out in parallel with the Wisconsin study. These models attempted to evaluate the most cost effective alternatives for individual customers.

Based upon the plant visits, the response categorization, and the limited optimization modeling, a response algorithm was developed for incorporation into the utility simulation model. This response algorithm was based on the assumption that within a given facility, total energy use would not change over a 24 hour period, i.e. given aggregate industrial demand as it exists under time of use rates, the total demand for a 24 hour period would remain constant under a spot pricing system. A translog mathematical function was developed which allowed the research team to compare the cost of energy consumed on a hour-by-hour basis between the existing time-of-use rate and the calculated spot price. The difference between the time-of-use rate and the spot price was then used to create the ratio of distribution of energy usages between hours in a given 8 hour shift. Load was rescheduled based on the following set of heuristic rules.

- o Rescheduling was most easy within a given shift
- o Rescheduling was second most easy when it shifted load and manpower from night to day.
- o Rescheduling was most difficult when it required rescheduling of manpower and energy use from a day shift to the night shift.

The customer response analysis was then incorporated into the utility impact analysis through development of two parallel scenarios which represented a low and a high level of response on the part of the aggregate industrial consumer group in the prototype utility.

The results of the customer response analysis were significant in our evaluation of the overall benefits to spot pricing. Our analysis indicated that rescheduling of electric energy use was possible in nearly every facility. This, despite the fact that many plant managers argued initially their schedules were too tight to be able to take advantage of short price changes. This appeared not to be the case when one evaluated the current practices in "beating the demand charge" which employed, from the utility's perspective, suboptimal rescheduling activities. The critical questions associated with rescheduling for an individual facility are those of the cost-benefit between the current rate structure, a flat rate structure, and the spot pricing structure and the issue of what pricing cycle is the most appropriate, both in terms of transaction cost and in terms of the ability of the individual customer to respond. These pricing cycles ranged from minutes to months.

The further conclusion of the customer response analysis was to identify specific types of facilities which showed a significant ability to response to spot pricing. In general these facilities were ones that have product storage (this represents a cost-free storage of electrical energy). An example of such storage is in industrial gas production where no energy is lost if the compression facilities are shut down for some specific amount of time to respond to a change in energy price. A similar case exists in the compacting of scrap metal into bales, where once again, the schedule may be shifted so long as some excess capacity remains. The second best type of facility to respond to spot pricing were facilities with processes that had both high demand and high thermal mass. An example is electric arc furnaces. A number of visits were made to facilities utilizing electric arc furnaces in both ferrous and non-ferrous processing. In all instances it was shown that the facilities were taking advantage of cost savings through demand limiting activities which saved money for the customer but did very little to assist the utility in its cost of production. A second example of those facilities which have high thermal mass and thereby the possibility of using thermal mass for storage are large buildings which have air heating and cooling equipment. The building itself can act as the storage unit for electrical energy in the form of cool or hot air for some amount of time. In both the case of the electric arc furnaces and the building systems, the cycle length will determine the ability of the system to respond. In general then it was seen that the customers had the ability at the industrial and large commercial scale to respond to spot prices, particularly the 24 hour look ahead spot price which offered the customer the greatest ability to plan ahead in a reasonable cycle for the production of the facility.

Utility impact analyses were carried out using an existing utility simulation model, ENPRO, developed by ENTEC of Rockland, Maine. The ENPRO model is a Monte Carlo simulation of hourly demand for a utility system. The model was modified in order to allow the research group first to calculate the hourly cost of generation, i.e. the spot price based upon the unmodified demand. Given the spot price, the demand was modified according to the demand modification algorithm and the cost of generation was recalculated. The system was then iterated once to see the sensitivity of the hourly structures to increased fine tuning of the customer response/generation loop. The ENPRO model was felt to be a successful simulation tool for this purpose. The Monte Carlo structure allowed for a range of forced outage conditions to be evaluated for each hourly period.

From this analysis it was shown that there were short term fuel savings in the range of 1 and 5 percent. In the longer term, the results show that up to a 5 percent decrease in reserve margin requirements would be brought about by the customer response to spot pricing without any change in system reliability. The major conclusion was that the spot pricing structure and the customer response to it offered to the utility the potential for "stretching" of the utility capital stock. This meant that the utility could utilize its existing capital stock more efficiently and, in the future, would add additional stock that would reflect this change in consumption and customer response patterns.

Customer bill impact analysis was carried out both at the aggregate, i.e. total industrial class level and at the disaggregated or individual company level. At the aggregate level revenues were estimated given both a current time of use rate structure and the proxy system lambda or spot price for electricity for the class as a whole. Given the results of the two analyses, with spot price and with time of use rates, it was possible to see that the utility would have under-recovered revenues using the spot price system but that under recovery was only of the order of 6 to 7 percent. In general it can be stated that the level of revenue recovery is a function of the utility's level of excess capacity and the relative level of optimization of the utility generating stock. In a system with high excess capacity, the utility will under recover revenues. In a system where capacity is short, the utility will over-recover. By the same token, in a utility that is poorly optimized given today's fuel cost structure, the utility will over-recover. A utility that is well-optimized in today's structure will either break even or slightly under-recover.

The issue of revenue reconciliation is not dealt with extensively in the report nor was it in the project as a whole. There is a significant literature available on revenue reconciliation which focusses on an attempt to reconcile through the rate structure in such a way as not to affect the basic economic signals or prices being sent to the individual customers. This can be done either through an adjustment on a pro-rata or on a fixed cost basis. Either of these will satisfy the basic conditions of revenue reconciliation quite simply in an instance in which the revenue gap is small. Because this study handled only one prototype utility, and that prototype utility showed a small revenue gap, the issue does not arise as significantly as it could were a large revenue gap were to appear for a specific utility under investigation.

The disaggregated customer bill impact analysis encountered a number of difficulties. In the initial analysis of specific customers much of the data by hour was missing. As a result the data was filled in through an averaging procedure which did not affect the aggregate analysis but did affect the disaggregated analysis. In addition it has long been know that there are inter-class subsidies between individual customers. This showed in the analysis of the individual customer bills.

The individual bill analysis looked at a limited sample of large customers with varying types of consumption characteristics, ranging from relatively flat load to extremely peaked loads. It was shown that some of these customers, with no response to spot pricing, saved funds by maintaining their behavior and simply receiving the new price structure. Other customers, particularly those with highly peaked loads, were shown to be at a distinct disadvantage under the new price structure. It must be emphasized, however, that the individual analyses were non-random samples and were taken from incomplete data assuming no response on the part of the individual customers.

RECOMMENDATIONS

It is recommended that:

- o Wisconsin proceed to the next step in the design of spot pricing experiments and spot pricing rates for large industrial customers. This analysis and other work under way indicates that the potential for societal savings and for customer benefit from participation in spot pricing rates are such that experiments should begin.
- o The State of Wisconsin adopt a framework of an instantaneous spot price in which to analyze and evaluate alternative electric services offered to all levels of customers. The concepts of the instantaneous spot price should be expanded to commercial and residential customers at least in so much as the rate design, cycle length, and the ability to rationalize between utility rates can be brought into focus.
- o The concept of an instantaneous spot price should be used to rationalize all existing utility rates and load management programs.
- o The utilities should assume the lead in the design and marketing

of a range of internally consistent services to their customers which will focus on the needs of their customers in terms of cost savings, and as a result, using the basics of spot pricing benefit to the utility. These benefits can be seen in terms of overall cost savings, in terms of the energy requirements of the individual customers and in terms of the reliability requirements of the individual customers.

- A spot price experiment focussed on large consumers should be designed within the State of Wisconsin. This should take four major issues into consideration.
  - Customers should be identified who are on time of use rates (all current large industrial customer). Customers should be identified who currently have energy management computers or have the ability to respond with human schedulers to changes in energy prices. Customers should be chosen who have the ability either to store or reschedule energy use. This would focus attention on industrial gas, ferrous and non-ferrous scrap metals systems using electric arc furnaces and metal scrapping activities. Finally, customers should be identified on the basis of the price cycles that they require in order to be able to respond to spot pricing.
  - Utility implementation. Utilities should work with their own system operators to develop simple means of predicting spot prices that would be in the medium to long-run automatic within the utility. In addition they should work to develop simple means for signaling prices to customers and for evaluating response to those price signals. The

utilities should thoroughly evaluate the hardware requirements for spot pricing experiments and for spot pricing implementation based on the generic requirements for analysis of individual customer loads, for communication with the customer and for the customers response to spot pricing signals.

- Regulatory actions. The regulatory structure should explore the implications of using existing time of use rates for spot pricing experiments through adaptation of, for instance, the current fuel adjustment clause. It is anticipated that existing rate structures will allow for sufficient flexibility to move forward with experiments in spot pricing prior to the time at which new, spot rates can be set and agreed upon in the state. In addition, the utility should encourage the development of alternative rates for all customer classes which can take advantage of the concepts of the instantaneous spot price.
- Research requirements. Additional research and development is required in the area of customer response and monitoring customer consumption patterns looking for critical loads and looking for ways in which customers can respond to specific lengths and levels of pricing for spot prices. In addition the impact on the utility of different types of spot pricing structures and cycles should be evaluated in greater detail particularly as additional experimental data becomes available.