ENERGY LABORATORY

MASSACHUSETTS INSTITUTE OF TECHNOLOGY

UTILITY SPOT PRICING: CALIFORNIA

Prepared for:

Pacific Gas and Electric
and
Southern California Edison

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MIT Energy Laboratory Report No. MIT-EL 82-044

December 1982

FOREWORD

The project managers for this effort are Al Garcia (PG&E) and Jack Runnels (SCE). This project could not have been done without their help. They contributed significantly to the technical development as well as providing the essential coordination with their respective organizations.

Many other persons at PG&E and SCE also contributed directly to this effort both during initial discussions and via feedback on preliminary drafts. PG&E and SCE provided all of the data and help we requested.

Naturally, MIT remains responsible for the content of the report itself.

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CHAPTER I

INTRODUCTION AND EXECUTIVE SUMMARY

Recently, there has been discussion about what long term business strategy electric utilities should pursue. Some have recommended extended diversification. Others have recommended deregulation. Still others have recommended the utility operations be abandoned altogether as a business opportunity for investors.

Many in the industry are coming to believe that these options are not necessarily the best options. They believe that a better strategy would be to take another look at the existing utility business from a sharper marketing and financial perspective.

The cornerstone of this emerging utility business strategy is to price electricity based on the cost of providing the commodity at any given time. Such a pricing strategy enables the utilities to better match their capacity to customer demand as the customers react to the changing costs of supply.

Such a pricing policy must be developed using a systematic, cohesive framework. "Spot pricing" of electricity offers one such framework. Spot pricing is the logical extension of the marginal cost framework used by Pacific Gas and Electric (PG&E) and Southern California Edison (SCE) today. It draws on principles that are used by utilities in economic dispatch and inter utility transactions to take advantage of capital and operating economies. Spot pricing can be viewed as a natural evolution of present day load management techniques.

The objective of the present spot pricing study carried out for SCE and PG&E is to develop the concepts which would lead to an experimental design for spot pricing in the two utilities. The report suggests a set of experiments and outlines implementation plans that can build upon existing and experimental load management programs and rates. The report also contains a description of spot pricing as well as a survey of the relevant literature. It categorizes the current and experimental rates in use in the two utilities, and relates them to spot pricing. The report further categorizes and evaluates hardware available for spot pricing experiments and implementation based upon the functional requirements of the customer/utility interface.

I.1 The Basic Concepts

Spot pricing is the setting of prices to reflect real time based incremental costs of providing electric energy such that the demand is always satisfied.

Spot prices are determined by prespecified formulae whose inputs include fuel costs/availability, generation plant outages, weather conditions, and operating reserve margins. These prespecified formulae are regulated by the regulatory commission.

Three main characteristics of spot prices are:

o Length of Price Cycle: Time between price level updates (e.g., 1 year, 1 month, 1 day, 1 hour)

o Period Definition: Definition of pricing periods within cycles (e.g., three time of use periods or 24 hourly periods in a daily cycle)

o Number of Levels: Number of levels from which the price during a given period may be selected. Can be finite (e.g., 2 or 3) or continuous.

Spot prices with different characteristics are all derived from "instantaneous spot prices" and are therefore internally consistent.

Spot pricing has communication, metering and billing transaction costs which depend on the characteristics of the spot price. Customers have different abilities to respond to changing prices. Therefore, different customer classes see spot prices with different characteristics which are determined by cost benefit tradeoffs. For example, a residential customer might see a spot price which is updated once a month, while a large industrial customer might see spot prices which are updated each hour.

Spot pricing can be implemented using today's technologies. It can coexist with existing rate structures and load management techniques. As with existing rates, spot pricing requires revenue reconciliation to adjust net revenue relative to allowed rate of return on capital investment.

Spot pricing can give customers a choice. They can control their costs by adjusting their consumption to match its perceived value. Forecasts of future spot prices are available to allow rational planning and decision making. Manual control is possible. Customers can reprogram their Energy Management Systems to respond to spot price variations. Customers can have the option to choose rates with different characteristics and/or make use of utility provided control services which turn off specific devices whenever the price exceeds a customer chosen level. New specially designed controllers wil become available to customers.

Spot pricing can provide the utility with an additional vehicle to help control the operating costs it incurs in satisfying customer demand. This is achieved by higher spot prices during times of high incremental utility operating costs (leading to reduced demand) and by lower spot prices during times of low incremental operating costs (leading to increased demand).

Spot price rates exhibit short term variations with time. However, annual energy bills will smooth out the effect of such variations. Risk adverse customers can have the option of participating in a futures market.

Spot pricing can affect capital investment decisions by both customers and the utility. Customers have incentives to invest to exploit the potential of spot pricing. Utility investment reflects the stabilizing feedback effects of spot pricing on customer demand patterns.

Spot pricing can provide an alternative to rotating blackouts under conditions in which rationing would be required. It reduces the social cost of having insufficient generating capacity.

Spot pricing yields a single, internally consistent framework for analysis and development of rates and services. All present rates can be interpreted and analyzed in terms of spot pricing principles.

Spot pricing can improve the equitable distribution of electricity costs by reducing cross subsidies, both within and between customer classes. Under spot prices, customers pay what it costs the utility to meet their demand, subject, of course, to decisions made on the method of revenue reconcilliation.

No single action or approach can solve all of the problems of the utility industry. However, spot pricing moves the industry forward along a path it is already following. Spot pricing brings the customer in as a responder to the time-varying costs of providing electric energy. Spot pricing exploits the revolution in microprocessing and in communication to establish an energy marketplace where costs and values are reflected in buy-sell decisions rather than regulatory proceedings or special legislation.

I.2 Implementation Recommendations

Today, the theory of spot pricing is well established. However, there are also many uncertainties. In particular, neither direct operating experiences with spot pricing nor accurate models for customer response are available. Therefore, the report does not recommend a firm commitment to implementation at the present time. Instead, the report presents a staged plan consisting of

- o An Experimental Phase
- o An Initial Implementation Phase
- o A Full Implementation Phase

Key decision points are timed to prevent premature commitment to any particular approach.

The report recommends that the Experimental Phase be started as soon as possible. The Experimental Phase is designed to provide experience with and detailed response analysis of a relatively small number of customers. Although most near term benefits of spot pricing are expected to be obtained from large industrial and commercial customers, the Experimental Phase includes a broader class of customers in order to provide information needed for substantial decisions. The report recommends that implementation move toward a balanced menu of transactions involving both new and existing rates and services.

The recommended new rates based on energy pricing (cents/KwH) are:

1 HOUR UPDATE SPOT PRICE: A price for electric energy set each hour to reflect the expected cost of generation, transmission/distribution and reliability. (Price cycle = 1 hour)

24 HOUR UPDATE SPOT PRICE: A price for electric energy for each hour of the next 24 hours which reflects the expected value of the one hour spot price. The prices are set one day ahead. (Price Cycle = 1 day, 24 pricing periods)

1 MONTH UPDATE SPOT PRICE: A price (or set of time of use prices) for electric energy set one month ahead which reflects the expected value of the one hour spot prices for the next month.

The report recommends that a basic spot price rate with a specified price cycle length and pricing period definition be established for each customer class. Individual customers will have the option to select rates with shorter cycle length and less aggregate pricing period definition as long as they cover the cost of additional hardware and/or communications costs incurred by the utility.

The report recommends that the utility supplement the menu of energy based rates by offering a variety of services to help the customers exercise real time control of their energy usage. Initially, such services should be based on hardware from existing load management systems, such as hot water heater control, air conditioning cycling, interruptible service and

Demand Subscription Service.

The report recommends that all steps toward implementation be closely coordinated with research and development programs designed to answer unresolved planning, operational, and design questions.

A key point in the overall implementation plan is the time at which full spot price adoption occurs; that point at which it is agreed by the utility and regulatory commission that all future rates and load management procedures will be based on a single, self-consistent, spot price concept. The report recommends that consideration of such a step be given high priority by the utility and the regulatory commission after the Experimental Phase is completd.

I.3 Summary of Report

The main chapters of the report are:

- Chapter I: Executive Summary and Introduction

- Chapter II: Summary of conceptual framework of spot price based transactions.

- Chapter III: Discussion of the overall implementation plan involving Experimental, Initial Implementation, and Full Implementation Phases.

- Chapter IV: Suggested details of Experimental Phase.

Extensive appendices are used to supplement the ma n text. The appendices are:

- Appendix A: IEEE Spectrum Paper on Homeostatic Control and Spot Pricing
- Appendix B: Review of Spot Price Literature

- Appendix C: Details of Spot Price Theory

- Appendix D: Detailed Characteristics of Spot Price Based Rates

- Appendix E: Relation of general concepts discussed in Chapter II to existing rates and load management techniques, with emphasis on the present utilization at PG&E and SCE.

- Appendix F: Review of Hardware Availability and Requirements

- Appendix G: Glossary of Terms

CHAPTER II

SPOT PRICING CONCEPTS

The purpose of this chapter is to outline the basic concepts of spot pricing. For a more general overview of spot pricing concepts, the reader is referred to Appendix A. Appendix B contains a literature survey. Some specific issues are presented in a more detailed fashion in Appendices C and D.

Customer response issues, a generic rate setting process and the determination of the "instantaneous spot price" are discussed. The general characteristics of practical spot price based rates are presented. These characteristics offer the utility and the regulators a spectrum of rates to choose from in order to match the utility's costs to customer needs and type of service desired. Finally, a number of related issues like the ability of spot price based rates to co-exist with other non-spot rates, revenue reconciliation, customer options, the handling of uncertainty and risk, the impact of the transmission and distribution network on spot price based rates and customer generation are discussed.

II.1 Customer Response

Customer response to time varying spot prices is key to the overall concepts. Customers plan their response based on reliable price forecasts.

Customer response, in general, depends on three factors: customer investments, customer operational decisions, and control actions at the time a spot price based rate comes into effect. Each of these factors is associated with a different time scale ranging from years in the case of investment to days or weeks in the case of operational decisions and to hours or minutes in the case of control. Thus, price forecasts that are relevant to the above three factors are also characterized by analogous time scales. The overall structure is summarized in Figure II.1.

Long term forecasts of spot prices are provided to customers to aid them in making investments. These long term rate forecasts are analogous to long-term load forecasts and are as predictable as future yearly load duration curves and variable generation costs are predictable today.

Operational decisions by customers depend on medium term rate forecasts which can be obtained reliably in a fashion analogous to daily or weekly load and variable generation cost forecasts used today by utility unit commitment planning.

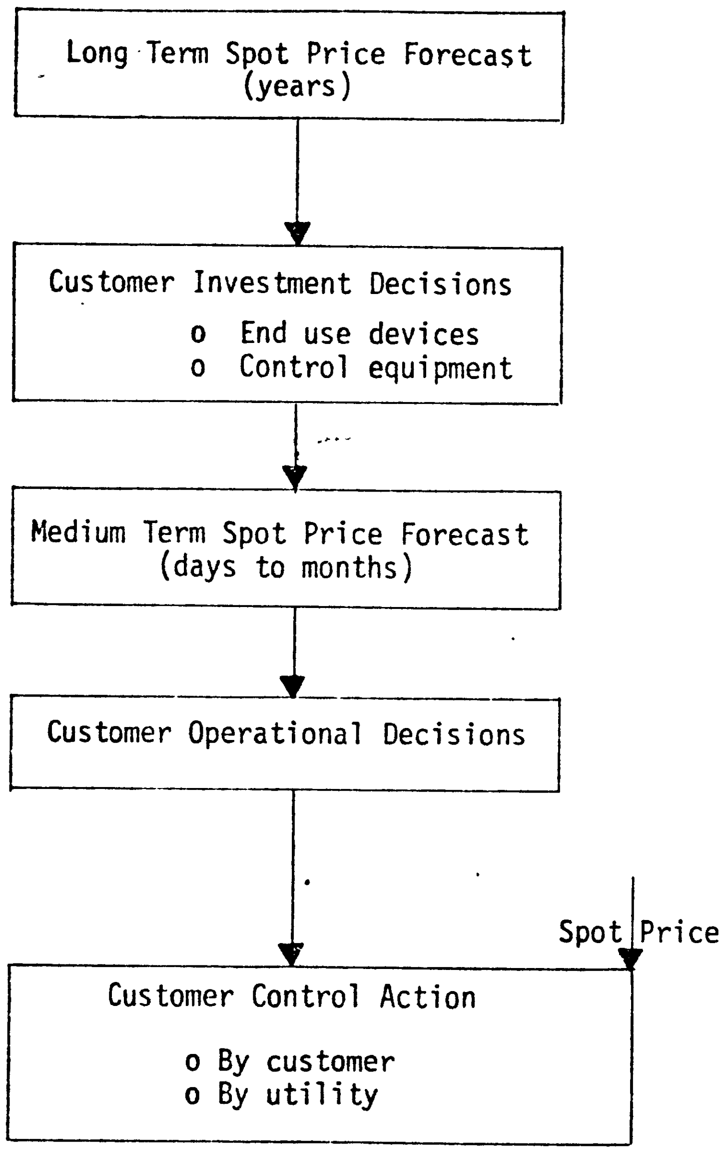


Figure II.1

Customer Response Behavior

Control actions which are analogous to generation control in today's utility functions, require repeated and short term response to the spot price based rates. The control action which implements customer operational decisions can be carried out by either the customer or by the utility following customer prespecified instructions. Utility exercised control can relieve the customer from the task of constantly responding to price changes if so desired.

II.2 Generic Rate Process

The implementation of spot price based rates follows a procedure involving a number of participants and actions as illustrated in Figure II.2.

Following the definition of a set of possible spot price based rates, the particular menu of rates to be offered is selected to match utility costs to customer needs. The selection is influenced by the characteristics of the utility system (generation, transmission, aggregate demand) and the customers (ability to respond, type of service required) as well as the related transaction, metering and communication costs. Since spot price based rates will vary over time depending on unknown a priori system conditions, a procedure(formula or algorithm) is determined for setting prices rather than the actual value of the rates. These prices, reflecting the conditions of the utility system at the time of computation, are communicated to customers. Customers make decisions concerning their desired consumption patterns based on matching present and future forecast of prices to their needs. Control action to realize the desired consumption pattern may be exercised either by the customer or by the utility. Metering and billing occur.

Evaluation of the consequences to the customer and the utility system are additional actions which provide information to be fed back into future considerations.

Figure II.2 sets the stage of the generic spot price based rate process. The basic principles of spot pricing are taken up next.

II.3 Instantaneous Spot Price

Since electricity is a non-storable good and its cost varies on a real time basis, the allocation of electricity generated to various uses should ideally be determined on a real time basis in order to minimize utility costs and maximize

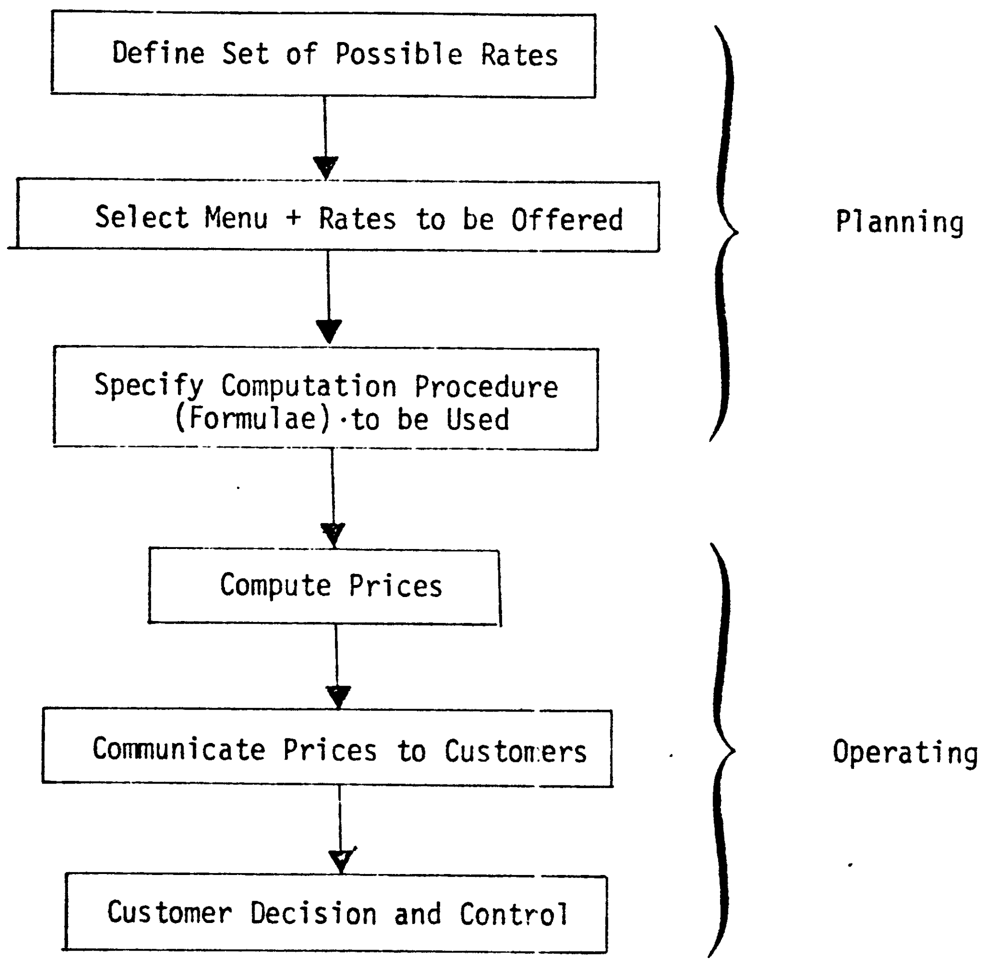


Figure II.2

Generic Rate Process

customer benefits. Indeed, the sum of customer benefits and utility savings can be maximized by economic dispatch on the generation side. On the customer side it can be maximized by consumer decisions based on an "instantaneous spot price" reflecting generating system costs and the value to consumers of electricity usage. Ignoring for the time the impact of the transmission and distribution network on generating costs (through losses, line overloads, etc.) the following relationship holds;

Instantaneous Spot Price =
Incremental Operating Costs +
Quality of Supply Component. (1)

The incremental operating cost component is related to "system lambda" used in economic dispatch but is not identical to it, since actual "system lambda" may be discontinuous or represent a signal that minimizes generating costs but does not necessarily represent system instantaneous marginal generating costs. The incremental operating cost term in relation (1) is defined as the expected change in variable system operating costs -- over the relevant unit commitment period (day or week) including costs of tie line purchases and subject to spinning reserve, ramp rate, capacity and other operating constraints -- with respect to an incremental change in system load at a particular moment.

The quality of supply component is selected so that the resulting price reflects the marginal value of expected unserved energy. In practice, the quality of supply component is be subject to a ceiling consistent with the coexistence of spot and non-spot price based rates (see Appendices C and E).

The instantaneous spot price definition above is effectively the instantaneous short run marginal cost. However, as discussed further in Appendix C, it might be possible to use an alternate formulation which is closer to a long run marginal cost philosophy.

II.4 Characteristics of Spot Prices

Implementation of instantaneous spot pricing is impractical because of the associated communications, transactions and metering costs. Therefore, a range of spot price based rates is considered which are related to the instantaneous spot price but are determined and posted before they come into effect. They are thus spot price based predetermined rates.

A predetermined price that maximizes the sum of customer and utility benefits is related to the instantaneous spot price as follows:

Price Determined at Time to to Take Effect at Time t = (2)

Expected Value of the Instantaneous Price at Time t Given the Uncertainty at Time to about Future Events.

In theory, an additional term should be added to this equation which depends on the nature of demand of the particular customer or customer class under the predetermined price. It may be zero, positive or negative. To a first approximation we assume here that it is zero.

There are various ways to evaluate the average value of the instantaneous spot price. A particular way proposed in Appendix C uses estimates of reserve margin and loss of load probability together with an a priori determined customer value of service model and an instantaneous price ceiling. The formula proposed in Appendix C enables spot price implementation based on well defined quantities that can be verified and agreed upon by all participants: customers, utility and regulators.

Appendix D provides a description of how relationship (2) can yield a spectrum of spot price based rates/contracts to fit the particular needs of a utility and its customers. Table II.1 summarizes some of the ideas of Appendix D by exhibiting three categories of spot price based rates/contracts. The basic framework consists of a spot market and a futures market.

The futures market can provide risk hedging and risk sharing among the utility, its customers and third party entities interested in participating; without compromising the cost minimizing features of spot price based rates.

The spot price market consists of price only and combined price/quantity transactions that reflect utility costs and customer needs, but differ in the level of costs and sophistication required for communication, metering, transaction implementation, decision and control actions.

The majority of present day "direct control" load management techniques can be viewed as combined price/quantity

TABLE II.1

Three Basic Types of Transactions

Type of Transaction	Properties
Spot Price Market	
- Price only	• Customer may use all kWh desired at quoted price • Prices set to reflect system marginal cost and maintain reserve margin
- Combined price/quantity	• Customer may use all kWh desired provided sufficient reserves are available • Customer contracts to limit use to agreed upon quantities when needed to maintain minimum reserve margin
Futures Market	• Customer can buy a fixed amount of energy to be delivered at a set time in the future for a fixed price • Customers buy and sell difference between actual use and contracted amount at spot price based rate

transactions. Examples include air conditioning cycling, water heating control, and Demand Subscription Service.

The most important characteristics of price only rates are summarized in Table II.2. One example is today's time of use rates with a price cycle length of four months, (frequency of energy cost adjustment) and a definition of pricing periods given by seasons and time of use (peak, off-peak and partial peak periods). An example of a new type of price only transaction is a 24 hour spot price profile calcuated every day and communicated to customers a few hours before it comes into effect (for example, late afternoon to become effective at 2 AM for the following 24 hours). The cycle length in this case is one day, the definition of pricing periods is 24 hours per day and the advanced notice is a few hours.

The number of different price levels depends on the restrictions imposed on the prices that can be communicated. For example, if prices can be any level there is no restriction. On the other hand, if prices have to be selected from a finite set of, say, 3 prices (i.e., 5, 10 or 15 cents per Kwh) the number of price levels is restricted.

Restrictions on the number of price levels to be communicated impact on the communication and metering costs. The currently practiced airconditioner cycling load management program can be viewed as a two price level spot price. When the spot price increases to the higher of its two allowable levels, the utility sends a signal (communicates the higher price) resulting in load shedding. The airconditioner owner has implicitly (decided) agreed in his contract to reduce his/her electricity consumption every time the spot price assumes its high level. The utility offers an additional service to the customer by exercizing control and activating air conditioner cycling at high spot price times.

A more complete description of the different types of transactions, their generic characteristics and their interraction with hardware requirements and costs is given in Appendices D and F.

II.5 Coexistence with Non Spot Rates

Imposing an appropriate ceiling on the instantaneous spot price as well as the role of reserve margin estimates in the formula developed in Appendix C render spot pricing possible with a concurrent existence of non spot price based rates/transactions. Customer groups not covered by spot pricing, a collectively agreed upon scheme of priorities for load shedding in cases of emergency, and other load management programs are all compatible with spot price based rates. The compatibility issue is discussed further in Appendix E.

TABLE II.2

Spot Price Based Rate Characteristics

Characteristic	Definition
Length of Price Cycle (Cycle Length)	Time between price level updates (e.g., 1 year, 1 month 1 day, 1 hour)
Period Definition	Definition of pricing periods within cycles (e.g., three time of use periods or 24 hourly periods in a daily cycle)
Number of Levels	Number of distinct price levels from which the price during a given period may be selected. Can be finite (2 or 3) or (continuous)
Advanced Notice	Time between posting a price and the time it comes into effect (e.g., 1 month, 10 hours, none)

II.6 Revenue Reconcilliation

Revenue reconcilliation is defined to be the process by which total utility revenue (over, say, one year) is adjusted to equal total variable operating costs (mainly fuel) plus capital costs with a fair rate of return on invested capital.

Spot price based rates are based on time varying incremental variable cost and a quality of supply component. Considering the weighted time average of these two components over the kwh quantities which they apply to during a period of one year yields:

- Spot price based rates without the quality of supply component realize revenues over and above total variable (fuel) costs.

- The net revenues from spot price based rates are increased by the quality of supply component.

The net revenues from spot price based rates may exceed or fall short of revenue requirement. The theory shows that under certain conditions including optimum investment configuration, spot price related net revenues should produce exactly the fair rate of return revenue requirements. Since, however, the requisite conditions are not likely to be met, spot price based rates usually have to be modified for revenue reconciliation. Appendix C discusses a number of theories for modifying spot price based rates to achieve revenue reconciliation. For example, all rates can be multiplied by a constant or a fixed charge can be used. An important criterion for selecting a particular approach is:

> The revenue reconciliation modification of the spot price should be done in a manner that least affects the consumption behavior of participants under spot pricing.

This report does not propose a "preferred" revenue reconciliation approach. The choice depends on the utility and the prevailing regulatory philosophy with the key issues differing little from those that are relevant in today's revenue reconciliation practice.

II.7 Customer Options

A range of spot price based rates with different characteristics may coexist. Thus the issue of which particular customers see which particular rate is important. The general criterion is that this matching be based on a tradeoff of hardware, communication, metering and other transaction costs versus the sum of utility and customer benefits. Benefits increase the closer the rate tracks "the instantaneous spot price". But communication and metering costs also increase. When rates characterized by long price cycles (i.e., one month or longer) and/or an aggregate pricing period definition (i.e., 3 periods per day or less) are considered, cross subsidy issues may arise.

A basic question is voluntary (by the customer) versus mandatory (by the utility or regulatory agency) rate selection. A general recommendation is that a basic minimum cycle length and detail of price period definition for each customer class (and possibly size, etc.) should be prescribed by the utility and the regulatory agency on the basis of cost benefit and cross-subsidy considerations. However, a customer should have the option to move to a rate with a smaller cycle length for a finer period definition as long as the customer is willing to incur the additional transaction costs.

II.8 Uncertainty and Risk

The time varying nature of spot price based rates suggests a higher degree of uncertainty associated with these rates relative to today's rates. Detailed discussions on variability, stability and uncertainty are provided in Appendix C. Three conclusions of that discussion are summarized here.

Spot pricing provides a feedback signal from the utility to the customers. Although it is theoretically possible for feedback to degrade system stability, presently available analysis indicates that simple types of spot pricing feedback can yield more desirable system properties (hours to days time scale) such as reduced sensitivity to uncertainties and to input perturbations.

Customers are more concerned with long term variations in their energy costs than with short term variations in spot price. Multiple year variations in an individual customer's annual costs will be determined primarily by external factors such as the national economy, oil prices, the customer's own desires, new generation technologies, etc. The difference between spot pricing and , say, time of use pricing on such variations will be relatively small (assuming that equivalent methods of revenue reconciliation are used).

In general, spot pricing reduces the uncertainties in some quantities while increasing the uncertainty in others. One potential concern is with uncertainties in an individual customer's ability to predict the annual energy cost for next year. We believe this is not a major obstacle to the implementation of spot pricing for several reasons. First, customers presently on direct control load management or interruptible contracts and/or customers threatened by rotating blackouts are already facing uncertainties in their total costs that could be larger than the uncertainties spot pricing introduces into their annual energy bills. Second, customers for whom uncertainty in annual energy bill imposes a significant financial risk have the choice provided by the futures markets. Risk averse customers can "insure themselves" by purchasing fixed amounts of electric energy to be delivered at a set time in the future for a fixed price.

II.9 Transmission and Distribution Impacts

The transmission and distribution (T&D) network is an important component of the utility system. Because of losses, power flow, and voltage constraints, the mathematical theory of spot pricing yields optimal spot prices which are differentiated by customer. Additional terms are added to the optimal spot price to reflect each customer's contribution to system losses and T&D network constraints. An optimal spot price for "reactive" power consumed by customers (generators and consumers) also arises.

The impact of the T&D network results in a spatial variation of optimal spot prices for both real and reactive power. The variation due to losses is usually on the order of ten percent or less, while the variation due to line thermal overloadings and voltage magnitude excursions can be much more significant at certain times.

Relationship (1) given in Section II.3 now becomes:

Instantaneous Spot Price at Time t, Location j
= Incremental Operating Cost at t
+ Quality of Supply Component at t (3)
+ T&D Network Losses Component at t and j
+ T&D Network Constraint Markup at t and j

The last two T&D components can be calculated by a loss estimation and a load flow estimation at time t. The losses term can be approximated in practice by using a DC load flow based quadratic losses formulation utilizing a B matrix. The T&D constraint markup is non-zero only at times of line overloadings or when line voltage magnitude constraints are binding. An AC based load flow calculation is needed to estimate this component which encourages a spatial redistribution of demand and generation to avoid the overload or the voltage magnitude excursion. The T&D network constraint markup can be either positive or negative, depending on the type of readjustments in generation/usage patterns required.

The spatial differentiation of prices introduced when T&D requirements are considered imposes additional requirements on the "Number of Critical Events" characteristic of price/quantity transaction contracts presented in Table D.2 of Appendix D and the "Number of Levels" characteristic of price only transactions presented in Table D.1 of Appendix D. The desirability to differentiate by voltage class and distribution substation argues in favor of a "continuous" number of price levels and critical events.

II.10 Customer Generation

Spot price based rates can prove very useful in incorporating customer generation into the utility system. Customer generation (i.e. cogeneration and small generators) must, according to the PURPA regulations, be purchased by the electric utilities at "full avoided cost". Avoided cost calculations and especially the energy versus capacity credit issue have presented formidable challenges for both the utilities and the regulatory commissions.

Spot price based rates can provide a consistent way to credit customers for electricity fed into the grid and satisfy PURPA regulations. The relationship of the spot price to marginal costs and avoided costs is discussed further Appendix C. It is worthwhile, however, to stress here the significance of using the spot price to credit customer generation in eliciting cost minimizing operational decisions. Customer generation earns more at times of high utility incremental operating costs or capacity shortages. Therefore, customers are motivated to generate more at times when their generation is most valuable to the utility and thus schedule their operation and maintenance according to overall utility system cost minimization criteria.

II.11 Summary Discussion of Spot Pricing Concepts

There are many types of spot priced based transactions that may be implemented to increase utility and customer benefits (see Appendix D). In most cases, offering customers a menu of transaction types rather than a single transaction type is desired. The combination of characteristics that are desirable may vary widely from utility to utility and depends on the costs and benefits involved. The particular needs and capabilities of customers and the utility as well as the communications, metering, control and transactions costs associated with a particular implementation determine its desirability.

Spot pricing is an extension and formalization of the marginal cost of service studies presented to the California Public Utility Commission over the last decade. Spot pricing can be viewed as extending the utilities' optimum generating dispatch logics to include the customers. Spot pricing can be considered as the logical evolution of present day load management techniques. Hence, spot pricing need not be considered to be a radically new, revolutionary concept.

CHAPTER III

OVERALL IMPLEMENTATION PLAN:

This chapter discusses in general terms the following multiple-phase implementation plan:

- Experimental Phase: 0-3 years
- Initial Implementation Phase: 3-6 years
- Full Implementation Phase: 6-10 years

More explicit discussions on the Experimental Phase are provided in Chapter IV.

The phasing schedule and plans will change and evolve with time. This overall plan provides a starting point. Some of the main features of each phase are summarized in Table III.1.

The Experimental Phase is designed to gain field experience resulting from spot price implementation for a relatively few customers in a closely controlled and analyzed environment. This will provide the understanding necessary to decide whether to proceed with spot pricing, and if so, to specify the initial menu of spot price based rates. The single most important goal of the Experimental Phase is to obtain acceptable models of customer response to spot prices.

The Initial Implementation Phase includes enough customers to have a real input on system operation and to provide broad-based statistical data. At the end of the Initial Implementation Phase, a comprehensive menu of spot price based transactions can be defined for the Full Implementation Phase. This multiple phase approach is designed to provide a sequence of key decision points timed to minimize the probability of a premature final commitment to any particular approach or concept.

Section III.1 discusses a key event in the overall implementation plan, the time of "Full Spot Price Adoption." Sections III.2 to III.7 follow the format of Table III.1, i.e., III.2 "Transactions;" III.3 "Utility Operations;" III.4 "Utility Planning;" III.5 "Price Demand Forecasting;" III.6 "Metering and Communications Hardware;" III.7 "Customer Control;" and III.8 "Customer Education." Sections III.9 through III.12 discuss questions associated with transmission and distribution effects; the futures market; customer-owned generation such as cogeneration; and the regulatory role. Section III.13 concludes by summarizing the associated research and development needs.

III.1 Full Spot Price Adoption

Perhaps the single most important event in any implementation scenario is the

- Time of Full Spot Price Adoption: The time at which a formal commitment is made to base all further transactions between the utility and its customers on spot pricing.

All customers need not see spot prices immediately after the "Time of Full Spot Price Adoption." However, the various rates, load management systems, etc., they do see are calculated using the spot pricing methodology. For example, residential customers previously seeing flat rates may continue to see flat rates, but the numerical values are calculated using spot pricing theory. Similarly, customers previously seeing some type of price/quantity contracts (say involving demand charges) could continue to see the same type of rate but with different numerical values after the time of full spot price adoption.

We view Full Spot Price Adoption as the next logical step in the evolution of electric rate structures. It involves a firm commitment to a single, integrated approach to utility-customer relations. Ideally such a commitment has an associated timetable predicting the types of rate structures to become available in the future. After such a firm commitment is made and a timetable predicted, the utility, its customers, the regulators, and private vendors can make plans in a less uncertain environment.

It is recommended that "Full Spot Price Adoption" occur during the Initial Implementation Phase. We do not recommend an immediate full spot price adoption. Such a commitment requires carefully developed statements of principles covering both the theoretical generalities and the practical concerns of actual operation. We can write such statements today but they would undoubtedly have to be changed.

III.2 Recommended Price Only Transactions

Table II.1 of Chapter II defined three basic types of transactions: price only, combined price/quantity and futures market. Price only transactions are the only ones recommended for testing during the Experimental Phase.

As discussed in Appendix D, combined price/quantity transactions have potential advantages and may very well have a role in the final menu of spot price based transactions offered to customers during the Initial Implementation Phase (which will in turn help determine the Full Implementation Phase). Experimentation with combined price/quantity is not recommended because extensive field experience is already available. However, further research on their role is recommended.

	Experimental Phase	Initial Implementation Phase	Full Implementation Phase
Transactions (see Section III.2)	o Selected price only transactions	o Initial menu of spot price based rates o Limited options	o Full menu of rates and options
Utility Operations -Implementation -Impact (see Section III.3)	 o Off line o None	 o On line o Limited	 o Full integration o Major
Utility Planning (see Section III.4)	o Develop tools o Cost benefit	o Full integration	o Refine tools and studies
Price-Demand Forecasting (see Section III.5)	o Operational	o Refine Operational o Planning	o Further refinement
Meter-Communication Hardware (see Section III.6)	o Existing	o Modify existing	o UMACS*
Customer control -Utility services -Private (see Section III.7)	 o Existing LM** o Existing EMS***	 o Modified LM o Modified EMS	 o UMACS* o Open
Customer Education (see Section III.8)	o Individualized	o Limited program	o Broad program

*Universal Meter and Control System

**Load Management Hardware

***Energy Management System

Table III.1

Summary of Implementation Plan

Experimenting with futures market transactions should be deferred until more information is available on price only transactions. Research on the nature and characteristics of futures market transactions is recommended.

The presently recommended price only transactions for the Initial and Full Implementation Phases are summarized in Table III.2. A "1 hour" cycle length is chosen because of the existing energy exchange transaction system (pool) between the various California utilities and between PG&E and SCE in particular. The 1 hour spot price is based on these energy exchange incremental/decremental costs with three additional terms:

- Transmission/distribution loss approximations.
- Quality of supply component which automatically increases the price in a predetermined fashion as the generation reserve margin decreases.
- Revenue reconciliation based on an annual average.

The 24 hour cycle length and 1 month cycle length prices of Table III.2 are obtained by forecasts (expected value in future) of the 1 hour spot prices. If desired, an additional term related to the expected impact of present demand on future capital expenditures can be added.

Use of a 2 or 3 level spot price as indicated in Table III.2 enables reduction in the metering, communication costs; see Appendix F. Such a 2 or 3 level pricing scheme can be particularly effective on the PG&E and SCE systems because they both have the characteristics of a relatively flat fuel cost for most of their operating time. Only rarely does the marginal fuel cost jump to high levels or does the reserve margin decrease sufficiently that the quality of supply component causes high prices. Hence, a price which is constant in time for most of the year but reaches high levels only at rare times can yield customer behavior that closely approximates "optimum" behavior. The 2 or 3 level spot prices are used primarily during the Initial Implementation Phase. They tend to be phased out during the Full Implementation Phase because their cost savings (versus continuous level) become small; see Appendix F.

A smaller subset of price transactions based just on 1-hour and 24-hour spot prices is suggested for implementation during the Experimental Phase (see Chapter IV for details).

The price only transactions of Table III.2 are supplemented with utility-provided customer control services which are primarily for residential customers. During the Experimental Phase and Initial Implementation Phase, these services are based on hardware from existing systems such as air conditioning cycling and water heater control. During the Full

Cycle Length	Number of Periods	Number of Levels	Advance Notice
1 month	o 1 per month o 2 or 3 per day	o Continuous	1 month
24 hour	o 24 per day	o Continuous	6 hours
1 hour	o 1 per hour	o Continous o 2 or 3	o 15 minutes o None

Table III.2

Recommended Price-Only Transactions
Initial and Full Implementation Phases

Implementation Phase, a more unified, generic central service is made available to the customers (see Section III.7 for further discussion).

The decision as to what type of basic and optional prices the various customer classes see during the Initial and Full Implementation Phases is based on cost-benefit analysis. Table III.3 illustrates the type of basic and optional price structure envisioned in the Full Implementation Phase. In the example of Table III.3, all customers in a "large industrial/commercial class" are on basic 1 hour spot pricing. Customers in a "small industrial commercial class" are on basic 24 hour spot prices, but have the option to go to 1 hour spot prices if they desire. "Residential class" customers are under basic 1 month spot prices but have options for either 24 hour or 1 hour spot prices. Customers in the "small industrial commercial" or "residential" class who choose an option for a shorter cycle length are expected to pay their fair share of the additional hardware and transactions costs. The exact definition and number of customer classes to be used is still open. Utility-provided customer control services are not illustrated in Table III.3.

Revenue reconciliation can be accomplished in many ways (see Appendix C). The final choice of approach may be utility specific and is subject to many concerns beyond the scope of this report. However, in general terms, our implementation recommendations are as follows. During all phases, revenue reconciliation is based on an annual average. During the Experimental Phase, adjustments are calculated to maintain already established revenue reconciliation levels within customer classes. During the Initial and Full Implementation Phases, revenue reconciliation terms are calculated on a more absolute basis. The impacts on cross subsidies between and within customer classes become important.

Experimentation with faster spot pricing (e.g., price cycle time is 5 minutes) is not recommended because its value (relative to its associated costs) is still not clear. However, more research on 5 minute spot prices is needed as subsequent analysis may show it to be desirable for some large customers, particularly those with large generation facilities.

III.3 Utility Operation

During the Experimental Phase, spot prices are implemented as follows:

- The once per hour pool incremental and decremental costs are sent to a separate off-line computational facility within the utility at the same time they are sent to the other utilities.

	Cycle Length	
	Basic	Option
Large Industrial Commercial	1 hour	----
Small Industrial Commercial	24 hour	1 hour
Residential	1 month	o 24 hour o 1 hour

Table III.3

Illustration of Basic/Option Structure

(Full Implementation)

- The off-line facility adds the necessary other terms to this basic quantity (loss approximations, quality of supply component, etc.).

- The off-line facility uses this data stream as well as other information to provide the necessary 24 hour price forecasts.

- The spot prices are transmitted and made available to the customers as appropriate.

It is recommended that the Experimental Phase be implemented in an operating center that is an off-line facility to minimize interference with real-time system operation. However, it is absolutely essential that system operation people be an integral part of these off-line efforts.

During the Initial Implementation Phase, the spot price operating center facilities are moved into the real-time control room and made part of system operations. It presently appears that in this phase, the primary impact of spot pricing will be during those rare occasions of high marginal fuel costs and/or low reserve margins with corresponding high quality supply of price components (i.e., during "emergency" type conditions).

During the Full Implementation Phase, spot pricing is integrated into all of the operating functions as appropriate (such as unit commitment, security assessment, etc.), i.e., it becomes part of both normal and emergency operation.

Discussions on how the extra terms are determined to add to the output of the pool incremental/decremental costs are given in Appendix C. Predicting prices 24 hours and 1 month in advance is discussed in Section III.5.

III.4 Utility Planning

During the Experimental Phase, major effort is expended on modifying existing system planning tools and developing new ones as necessary in order to evaluate a spot price marketplace environment. Emphasis is on cost-benefit analyses to define the types of transactions to be offered by customer classes, and their associated hardware systems.

During the Initial Implementation Phase, the potential impacts of the spot price are factored into most system planning functions.

During the Full Implementation Phase, the various tools and studies are refined as new information becomes available.

The main utility planning tools to be considered are

- Forecasting models for both price and demand.
- Production cost models.
- Generation expansion models.
- Corporate financial models.
- Transmission distribution design techniques.
- Uncertainty trade-off analysis techniques.
- Customer value of service models.

The development of forecasting models is discussed in Section III.5. Production cost models (either the Monte Carlo or probabilistic type) are modified to incorporate spot price effects. Generation expansion packages are modified to work with such production cost models and also to operate in a mode wherein customer value models are used along with spot pricing to replace the concept of a hard constraint on reliability (as measured by installed reserve margin, loss of load probability or expected unserved energy). Some modification of corporate financial models is also required. Full implementation of spot pricing can have a major impact on the planning of transmission distribution systems, but this is an area which has not been investigated in detail as yet. The development and use of system planning tools which directly treat the massive amounts of uncertainty that presently exist is needed independent of whether or not a spot price marketplace environment exists. However, a spot pricing marketplace may be better able to deal with uncertainty because of the stabilization resulting from feedback.

III.5 Price Demand Forecasting

Forecasting/modeling of price and demand over different time intervals is important to both customers and the utility.

For the purposes of discussion, a distinction is made between a forecast and a model where:

- Forecast: Number or series of numbers versus time indicating the best estimate of a future quantity (ideally with associated uncertainty measures).

- Model: A mathematical or mental set of relationships between variables such that when the exogenous input quantity variables are specified (such as weather, economic conditions, etc.) the output is the desired forecast (a model may or may not be implemented as a computer program).

Three basic types of quantities of concern are:

- Price: Forecasts of future prices are needed by the customers to make decisions and exercise control.

- Demand Response: The utility needs forecasts of future demands with price as an exogenous input.

- Value of Service: The utility needs to model the value of service to the customers to determine the quality of supply component of the spot price.

Two time scales of concern are:

- Operational: Concern is with operational issues (one hour to one year) in which the capital investment by both the utility and customer are fixed.

- Planning: Time intervals of one to many years where it is necessary to consider the impacts of changes in capital investment as well as operation.

The necessary models and forecasts are developed using presently available techniques and methodologies. However, major efforts are required to accomplish the needed developments. Fortunately, a multiple-phase implementation plan provides time to gather the data and do the analysis before enough customers are seeing spot prices to require accurate price and demand forecasts from the utility operation point of view. Accuracy in value of service models is needed to be "fair" to customers but is not essential to power system operation.

During the Experimental Phase, 24-hour forecasts are obtained using simple time series techniques or table look-up combined with insights from the system operators and/or computer outputs on what is expected the next day. Value of service models are taken from other studies.

During the Initial Implementation Phase, operational forecasting techniques and value of service models are refined and formalized. Major effort is devoted to developing tools for the planning time scales.

During the Full Implementation Phase, the models and forecasts are continuously refined as more information becomes available and the overall understanding improves.

An important question is

- Should the utility provide a price forecasting service to the customers?

First it seems reasonable for the utility to provide this price forecasting service as the utility has access to all the necessary information and is making such forecasts anyway. However, if the utility does provide such a service, the utility can find itself in an awkward position when the forecasts turn out to be wrong (as they will be at times). Customers might accuse the utility of manipulating the forecast for its own benefit. In order to circumvent this problem, the utility could make available all the basic information to private "information consultants" who would then forecast future prices and sell the forecasts to the customers. At the present time, we feel that the private information consultant approach is preferable in the long term and hence recommend the following.

- Experimental Phase: Utility provides price forecast service to customers.

- Initial Implementation Phase: Utility provides forecast service, but also makes basic information available to information consultants and encourages their operation.

- Full Implementation Phase: Utility makes price forecasts for its internal use but does not provide this service to the customers.

III.6 Metering and Communication Hardware

As discussed in detail in Appendix F, spot price implementation requires

- Metering electrical use for each price period
  - o Energy
  - o Demand (possibly)

- Communication
  - o Price change from utility to customer
  - o Price period change from utility to meter
  - o Electricity use from meter to billing computer.

Consider metering first. During the Experimental Phase, existing meter types are used exclusively. For the majority of cases, meters that are already installed are used. Research on a Universal Metering and Control System (UMACS) starts. (UMACS is discussed further in Section III.7.)

During the Initial Implementation Phase, reliance is still placed on existing meter types. Developing and testing of the UMACS starts.

During the Full Implementation Phase, final UMACS design is specified. Conversion occurs as fast as practical.

Now consider communication. During none of the three implementation phases is a new, electronic utility customer communication link absolutely needed. For example, even in the Full Implementation Phase, 1 hour spot pricing could be implemented by making it the customer's responsibility to have its computer make a telephone call to the utility once an hour to learn the new price. Direct electronic links are required for utility-provided control services, but these could be of types that are already in the field. In this report, we make no explicit recommendation on the types of electronic links to be used. It is expected that decisions for implementation of new types of communication links will be based on many applications of which spot pricing is only one.

III.7 Customer Control

As was discussed in Chapter II, a distinction is made between decision and control

- Decision: Act of deciding what strategy or policy should be followed under different types of conditions.
- Control: Act of turning on and off devices to implement decisions.

where two types of control are:

- Utility-Provided Control Services: Utility provides the actual control signals to end use devices in a way which implements customer decisions.
- Customer Control: Customers use their own manual or electronic control systems to implement their own decisions.

Consider first, utility-provided control services. During the Experimental Phase, utility-provided control services are based on the existing load management hardware. Research is started on the Universal Meter and Communication System (UMACS).

During the Initial Implementation Phase, the existing hardware is modified if appropriate. Detailed development and testing of the UMACS is started.

During the Full Implementation Phase, the UMACS receives final development and is used as the main vehicle for utility-provided control services.

A Universal Metering and Control System (UMACS) was discussed above and in Section III.6. The UMACS concept combines the results of Appendix F with the fact that a relatively simple, fixed digital logic can be made to "act like" an extremely wide range of possible utility-provided control services by simply changing parameters and inputs. It is possible to develop a small set of "generic" or "universal," microprocessor based metering-control boxes which can eventually replace today's standard meters.

A UMACS is not intended to replace customer-owned energy management systems (EMS). An EMS helps customers implement sophisticated decision and control functions. A UMACS is intended for customers satisfied with simpler utility-provided control services. One distinguishing feature of a UMACS is that it does not accept or make use of real time monitoring data on internal customer processes. An EMS, on the other hand, usually makes use of real time temperatures, power levels, flow rates, etc., measured within the customer's domain to provide a "closed loop controller."

Now consider control which the customers provide for themselves. During the Experimental Phase, this control is based on modifications of already installed energy management systems (EMS) combined with customer manual actions. Because of the nature of the PG&E and SCE systems (relatively flat prices with high prices rare), the use of manual control by the customers can be effective during this phase.

During the Initial and Full Implementation Phases, the range of services offered to customers by private vendors greatly expands. At the present time it is difficult to predict what will happen. It will be a volatile, fast-moving field.

An important question is

- Should the utility compete with private vendors to offer energy management control systems to the customers (beyond the control services already recommended)?

We have no recommendation. The answer depends on whether the utility wants to diversify its range of interests and whether such diversification will be allowed by the regulatory agency.

III.8 Customer Education

The spot pricing/marketplace environment provides a whole new world for customers and it is necessary to mount a major effort in customer education so they can learn how to deal with it. Failure in the customer education area will lead to failure of spot pricing.

During the Experimental Phase, customer education is individualized as much as possible. Industrial commercial customers seeing spot prices have a utility representative working directly with them to help determine what to expect and how to respond. Residential customers receive both personal interviews and general educational materials. Research and development on broad educational techniques aimed at aggregate customer classes are started.

During the Initial Implementation Phase, the use of broad education programs at the various customer class levels is started. The utility encourages private consulting firms to work directly with customers. At the residential level, the utility supports the development of electronic teaching aids for use in home computers or in a home game environment.

During the Full Implementation Phase, broad-based educational techniques are employed. In the residential sector, these include use of television and provision of facilities/materials for both grade and high schools.

An important question is:

- Should the utility eventually leave education to private industry and/or public education?

Considering the importance of customer knowledge to the overall behavior of the electric power system and the closeness between utility and customer, it seems unlikely that the utility would ever find it desirable to ignore customer education.

III.9 Transmission Distribution Effects

The general theory of spot pricing incorporates losses as well as voltage magnitudes and line loading as considerations into the determination of spot prices. These quantities are time-varying in a random fashion as they depend on generation and load geographical distributions, line maintenance switching, and line outages due to unforeseen events. Implementation questions center on the degree to which these time-varying relationships are incorporated into the actual spot pricing formulae.

An open question which has to be resolved is whether the regulatory commission will allow different customers within the same class but at different locations to see different prices. Such spatial pricing is logical and desirable from economic and engineering points of view but may be deemed politically unacceptable. The following assumes spatial pricing will be allowed.

During the Experimental Phase, real power pricing is used for all customers and loss effects are based on average conditions. This simplifies implementation and allows effort to be put in areas which are felt to be more important. Research on more sophisticated approaches is started.

During the Initial Implementation Phase, emphasis continues to be placed on simple, real power pricing. Detailed studies are done to determine advantages of incorporating the various levels of sophistication including transmission distribution effects. Time-varying transmission distribution effects are incorporated into the statement of "Full Spot Price Adoption."

During the Full Implementation Phase, time-varying transmission distribution effects and reactive power pricing are used as appropriate. Large customers might see spot prices (both real and reactive power) which vary as a function of transmission distribution conditions, while residential customers see simple approximations based on voltage level of service and customer density.

III.10 Futures Market

Implementation discussions so far have been devoted to price only transactions wherein the utility quotes a firm price (based on the utility's best estimate of what the costs are or will be) which is final for all the energy a customer wants. As discussed in Chapter II, such a spot price market could be combined with a more volatile futures market. For example, on January 1 one kWh delivered/used on July 1 might be selling for 10¢/KWH. However, on April 1, one KWH to be delivered/used on July 1 might be selling for 15¢/KWH, while on July 1 the actual spot price might be 5¢/KWH. Futures markets enable participants to share the risk of future uncertainties and to hedge against future events if they so desire.

An important question is:

- Should the utility manage or participate in the futures market?

This question is related to the question of whether the utility should provide customers with forecasts of future spot prices. The utility is in an excellent position to manage a futures market but if it does, the utility then becomes subject to criticisms that it is manipulating the market to its own advantage. We presently feel that it is desirable for the utility to encourage the development of a futures market that is independent of its own operations.

During the Experimental Phase it is recommended that a futures market not be offered to consumers. During this phase the basic techniques and concepts for the futures market start to be developed.

During the Initial Implementation Phase, experiments with the futures market are started along with attempts to interest outside groups in participation and running the market.

During the Full Implementation Phase, the utility may have to initially participate in the futures market in order to get it well under way but makes every effort to get out as soon as possible.

III.11 Combined Price/Quantity Transactions

The menu of spot price based transactions offered to customers during the Initial and Full Implementation Phases could include some combined price/quantity transactions in addition to price only transactions. During the Experimental Phase, further research is done on combined price/quantity and its relationship with price only with emphasis on cost-benefit trade-offs. This research draws heavily on the already existing field experience available on customer response to combined price/quantity.

A decision of which, if any, combined price/quantity transactions are to be offered during Initial Implementation is made at the end of the Experimental Phase.

III.12 Independent Generation

There are many advantages to the use of spot pricing buyback rates for independent generators that are either customer-owned (say cogeneration) or utility-owned but deregulated. However detailed considerations in this area were not made as part of this project. Hence no explicit suggestions are made here. The following outlines possible approaches to be followed if desired.

Spot pricing theory is basically symmetric; a price at a given point on the network at a given time is the same whether electric energy is being bought or sold. Revenue reconciliation could change this symmetry.

During the Experimental Phase, some independent cogenerators could be put on spot price buyback rates.

During the Initial Implementation Phase it could be desirable that all independent generation except very small units see spot prices. When "Full Spot Price Adoption" is seen, the principles should be stated to cover both customer purchases and sales.

Because of the stated desirability of customer-owned generation to SCE and PG&E, it could be desirable during the Experimental Phase to explore the possibility of developing a special futures market just for such customers in order to provide the financial stability that some customers and financial institutions feel is needed before large capital investments are made. The utility could contract to buy fixed quantities of energy (versus time) at specified prices for multi-years in the future (with, of course, any differences between the prespecified quantity and actual generation being treated as a spot market sale or purchase). The prices could be tied to economic indicators such as inflation rate, etc. If desired, either the utility or the customer could try to renegotiate the contract or "sell out" to third parties at any time.

III.13 Regulatory Role

The need for regulatory monitoring and overview is inherent in any regulated industry. Therefore the regulatory role in a spot price marketplace must be defined. However, this report does not provide recommendations. It only provides background discussions.

Two main areas where regulatory oversight is or might be desirable are:

- Evaluation and regulation of the particular formulas (and parameter values used in those formulas) used to calculate spot prices.

- Detailed oversight of daily operation.

There is no question that regulation of spot pricing formulas is necessary. However there are open questions on exactly which formulas are to be regulated and how. For example, calculation of 24 hour spot prices requires, among other things, forecasts of costs for the next day where the costs depend on demand which in turn depends on weather. Does this imply the need for regulatory oversight of the formulas/procedures used to make weather forecasts?

Since load management can be viewed as a type of spot pricing, the amount of regulatory oversight of spot price operation could be based on the precedents already established in oversight of the load management techniques. This seems to imply a minimal amount of direct regulatory oversight of operation as it appears that, in California, the regulatory commissions have not found it necessary or desirable to become deeply involved in load management, real-time, operating decisions.

There are, however, advantages to having some in-depth regulatory oversight of utility spot price operations. Some customers will eventually complain that the utility is manipulating the spot market to its own advantage by raising prices. The best way to protect against such criticism is to have a regulatory oversight procedure already in operation.

A major disadvantage of having regulatory oversight of daily operation is that utility operations are complex and are not readily susceptible to cursory overview. In order to do such overviews, the regulatory agency has to have, or obtain, individuals with professional training and experience in utility operations who can truly evaluate how the operations are conducted.

If it is decided that the regulatory agency is to overview utility operations, two important ground rules should be established. First, the overview procedure must be designed so as not to interfere with actual operation. Second, such regulatory review must be careful about the dangers of the "Monday morning quarterback," i.e., of deciding after the fact that certain specific operating decisions were "wrong" and then penalizing the utility. System operators have to make many real-time decisions in a complex, uncertain world and there are definitely times when unexpected events occur and it would have been better (after the fact) if alternative decisions had been made. Regulatory oversight of utility operations must evaluate the overall performance over the long term, and not concentrate on a few specific events.

III.14 Research and Development

Basic spot pricing theory is well developed at the present time. There are no insurmountable implementation obstacles foreseen. Nevertheless, an extensive research and development program is needed. Many open areas still exist. Even more important, actual experiments and implementation of any concept always uncovers new problems, not previously envisioned. Ongoing research and development are essential to deal with both types of problems.

The discussions of Sections III.2 to III.13 covered most of the needed research and development efforts. A summary listing of these efforts is contained in Table III.4. Table III.4 also provides a highly subjective measure of the relative degrees of development versus research that are required. The difference between research and development is often in the eye of the beholder. The definitions used for Table III.4 are

- Development: A way to proceed is known (may never have been done before). Explicit design and analysis leading to final decisions.

- Research: Involves much more uncertainty than development. Not necessarily clear on how to proceed. Interest more in general relationships and representative numbers than in final decisions.

Spot pricing is the key to only part of the overall approach called Homeostatic Control. (A discussion on Homeostatic Control is provided in Appendix A.) Another aspect of Homeostatic Control which is intended to be integrated with spot pricing is dynamics pricing. Dynamics pricing is concerned with faster time scale phenomena associated with dynamical response of boiler turbines, spinning reserve requirements, stability, etc. One particular example of a dynamic pricing concept is the Frequency Adaptive Power Energy Rescheduler (FAPER). Research and development on spot pricing should also have an associated research effort on dynamics pricing. The research on 5 minute spot pricing mentioned in Section III.2 should be correlated with dynamic pricing research.

	Recommended Relative Levels of: Development	Research
1. Transactions		
1.1 Specification of final formulae	10	--
1.2 Cost benefit	7	3
1.3 Revenue reconciliation	7	3
1.4 Price vs. price quantity trade-off	5	5
1.5 Cross subsidies	5	5
1.6 5-minute spot pricing	5	5
1.7 Price Stability	3	7
2. Operations		
2.1 Initial implementation	9	1
2.2 Complete integration	5	5
3. Planning		
3.1 Production cost	8	2
3.2 Generation expansion	5	5
3.3 Corporate financial	8	2
3.4 Transmission and distribution	2	8
3.5 Uncertainty trade-offs	5	5
4. Price/Demand Forecast Model		
4.1 Price	5	5
4.2 Demand	2	8
4.3 Value of service	2	8
5. Metering Communication Hardware		
5.1 Modify existing	9	1
5.2 UMACS**	5	5
6. Customer Control		
6.1 Modify existing LM*	8	2
6.2 UMACS**	3	7
7. Customer Education		
7.1 Individualized	8	2
7.2 Broad program	7	3
8. Transmission Distribution Effects		
8.1 Average losses	10	--
8.2 Time-varying conditions, spatial variation	4	6
9. Futures market		
9.1 Operation/structures	2	8

*Load management.

**Universal Meter and Control System.

Table III.4

Summary of Research and Development Needs

Chapter IV

EXPERIMENTAL PHASE

An overall implementation plan consisting of three separate phases was outlined in Chapter III. The present chapter provides more details on the Experimental Phase.

One of many possible approaches to the Experimental Phase is suggested. Neither PG&E or SCE are expected to follow these suggestions exactly, as they are intended to be used only as a starting point in the Experimental Phase design process. PG&E and SCE might consider coordinating their efforts or even a joint program, but suggestions on such possibilities are outside the scope of this report.

The three main goals of the Experimental Phase are:

- To show that spot pricing is an implementable concept.
- To gain field experience with spot pricing implementation in three areas; customer response, utility operation, and regulatory approval.
- To lay foundations for the Initial Implementation Phase and to conduct longer range research and development.

The most important single goal is to understand customer behavior.

Section IV.1 provides an overview of the experimental efforts while Section IV.2 discusses the associated fourteen tasks. Section IV.3 discusses four tasks needed to prepare for the Initial Implementation phase. Section IV.4 discusses basic research and development. Section IV.5 discusses project organization.

IV.1. Overview of Suggested Experiment

Experiment start up is expected to take six months. Data gathering, analysis, and research is to be done during the subsequent two years.

Continuous level, 24 hour update and 1 hour update spot price rates, and utility-provided control services are implemented. Concentration on a single spot price rate would not provide the information needed. Both 2 or 3 quantified level spot prices and 1 month update spot prices are recommended to be part of the menu for the Initial Implementation Phase but neither is included in the experiment. The experiment is designed to provide information and experience and not necessarily to implement the most cost-effective rates.

Customers from all major sectors (industrial, commercial, agriculture, and residential) are included in the experiment. Large industrial and commercial customers are the prime candidates for positive cost benefit results when seeing sophisticated spot prices. However the experiment includes a broader class of customers to help guide subsequent decisions.

Indepth understanding of customer behavior is the single most important result to be obtained from the experiment. The suggested approach places heavy emphasis on detailed observations and case studies of a relatively small number of customers. This is felt to be more cost effective than taking simple observations and doing statistical analysis of aggregate behavior for a large number of customers.

Emphasis on detailed data gathering and case study analysis means that customer selection is tailored toward obtaining customers with desired characteristics. Heavy reliance on formal statistical sampling techniques to select customers is not made.

During the experiment, customers receive direct assistance from utility representatives to help the customer learn how to respond. The interactions resulting from such customer education provide valuable inputs to the case study analyses.

No new types of communication or metering hardware are developed. It would be possible to design an experiment which relies almost entirely on already installed hardware. However, the suggested approach involves the purchase and installation of some new hardware (of already existing types) in order to obtain better experimental data.

Spot pricing opens the potential for many types of new microprocessor based communication, decision, and control devices. However the experiment is not designed to explore this area.

Reliance on indepth study of and interaction with customers plus reliance on already available hardware means the experiment has a higher percentage of personnel costs than in many past load management experiments.

IV.2 Tasks Associated with the Experiment

The start up, conducting, and evaluation of the experiment part of the Experimental Phase is divided into fourteen tasks:

Task 0	Simulate Instantaneous Spot Prices
Task 1	Specify Transactions
Task 2	Target Customers
Task 3	Develop Price Formula

Task 4 Specify/Order Communication-Meter Hardware
Task 5 Specify Price Forecast Services
Task 6 Obtain Regulatory Approval
Task 7 Train Utility Representatives
Task 8 Design/Implement Operating Center
Task 9 Select Customers, Install Hardware
Task 10 Conduct Experiment
Task 11 Customer Response Analysis
Task 12 Customer Education
Task 13 Evaluate Results

Task 0 should be completed before the commencement of the Experimental Phase. Tasks 1 thorugh 9 are associated with start up; Tasks 10, 11, 12, with actual operation; and Task 13 with evaluation of results.

Figure IV.1 summarizes the functional relationships between the thirteen tasks.

Each task is discussed individually. The discussions do not constitute a formal definition of tasks. They simply provide a starting point for further development and definition.

Task 0: Simulate Instantaneous Spot Prices

The purpose of Task 0 is to provide information on the behavior of instantaneous spot prices at SCE and PG&E.

Discussion: Instantaneous spot prices can be simulated from historical data compiled over the past years on incremental/decremental costs and reserve margins. Various spot price based rates can then be derived from the instantaneous spot prices and their variation and trends explored. Historical data from daily or weekly forecasts of marginal operating costs related to unit commitment exercises can also be compared to the corresponding actual costs to provide information on short-term forecast error. Such information is needed before commencing with the Experimental Phase.

Task 1: Specify Transactions

The purpose of Task 1 is to define the specific spot price based transactions to be offered to the customers.

Discussion: The menu of transactions to be offered to customers by usage classes is:

Industrial and Commercial:	Choice beween 1 hour or 24 hour update
Agricultural:	24 hour update

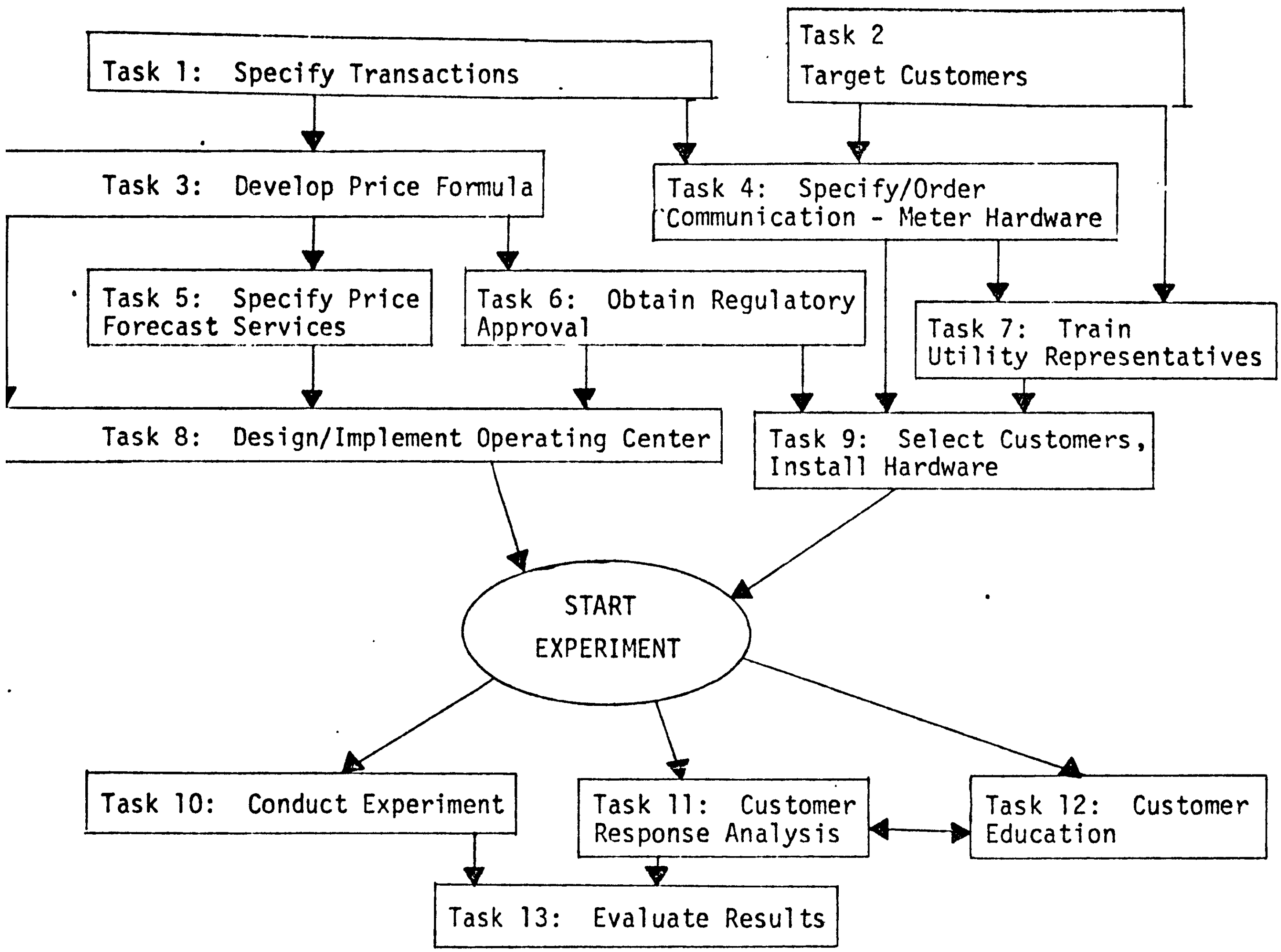


Figure IV.1

Functional Relationships Between Tasks
Associated with Experiment

Residential:	1 hour update with utility-provided control sevice

Continuous level prices are used. The 1 hour spot prices are made available 15 minutes in advance. The 24 hour spot prices (from 2:00 a.m. to 2:00 a.m.) are made available to the customer at 4:00 p.m. the previous afternoon.

The utility-provided control services for residential customers are based on existing hardware such as used for air conditioner cycling, or water heater control. The utility offers to control either specific devices or the maximum overall building demand, depending on a price level specified by the customer. The existing GLC and COOP program for commercial customers might be classified as a utility-provided control service but we have not chosen to do so.

Industrial and commercial customers are given a choice of transactions. This provides more information but it also complicates the experiment. During the customer selection process (see Task 9), care is taken to insure that a desired mix of customers on different rates is obtained. Alternatively, the existence of choice might be removed.

After the experiment being discussed here is operating satisfactorily, it might be desirable to start a second experiment involving one month update spot prices for larger numbers of residential and small commercial customers.

Task 2: Target Customers

The purpose of Task 2 is to specify the number of customers desired in each class and to target individual customers within the class.

Discussion: The following numbers of customers per class are based on our opinion that they will meet the goals of the Experimental Phase

Industrial	10
Commercial	10
Agricultural	5
Residential	20

As discussed in Section IV.1, the experiment philosophy is based on the use of in-depth data gathering and case studies on relatively small numbers rather than aggregate statistical analysis.

Individual customers are targeted based on their size, consumption patterns, and expected ability to respond. For larger customers, availability of energy management (or demand control) computer facilities is taken in consideration along with existing involvement in interruptible GLC, COOP programs. For larger customers, subjective information generated from discussion with utility representatives is used. The targeting includes roughly three times the number of desired customers.

A question for which we have no suggested answer is whether customers who are already involved in other experimental programs should be targeted for spot pricing. An obvious disadvantage is that such a step could confuse customers and analysis of their responses and also provide administrative headaches. Advantages are the potential lower cost of hardware and the ability to work with customers who are already sensitized to their electric consumption patterns and costs.

Task 3: Develop Pricing Formulae

The purpose of Task 3 is to develop the explicit formulas and procedures used to compute the actual spot prices the customers pay.

Discussion: The final choice of revenue reconciliation mechanism depends on the particular utility and class characteristics as well as political concerns. The suggested approach is to combine monthly fixed charges with a monthly surcharge or refund which is directly proportional to the spot price bill. The coefficients used in these calculations are based on annual averages.

The 1 hour update spot price is calculated as follows:

Step 1: The pool incremental/decremental costs are received once an hour. Spatial and level "averaging" is done to obtain a single number. If not received, simple extrapolation is done.

Step 2: The utility or California level reserve margin is received once an hour (extrapolated if necessary).

Step 3: The reserve margin is used to compute the quality of supply component which is added to the pool incremental/decremental value.

Step 4: Loss coefficents are used to get the one hour spot price (customer class specific).

Implementation of Step 3 requires mathematical models (both formula and parameter values) for the value of service and for the reserve uncertainty for the next hour. The value of service model is obtained from whatever is presently available in other studies. Initially it is suggested that the reserve uncertainty model consider a Gaussian approximation (even though the true distribution may be nonsymmetric). If acceptable from a regulator point of view, it is desirable to be able to change the value of service and reserve uncertainties models during the experiment after more knowledge has been obtained. The loss coefficients needed in Step 4 are based on availble data on losses by voltage class and customer class.

The 24 hour update spot prices are calculated as follows:

Step 1: The previous afternoon, the pool incremental/ decremental values are forecasted for the next day (2 a.m. to 2 a.m.)

Step 2: The previous afternoon, reserve margins over the next day are forecasted.

Step 3: The forecasted reserve margin is used to compute the quality of supply component to be added.

Step 4: Loss effects are incorporated.

Implementation of Step 3 inquires modeling of the growth in reserve uncertainty with forecast time. If a Gaussian model is used, the variance is a function of time.

Initially, the calculation of 24 hour update spot prices relies heavily on simple table look up of similar past days combined with judgment done at time of emergencies. Assuming that regulatory approval of the explicit forecasting formulas and procedures is not required, more sophisticated forecasting techniques based on a combination of time series and other statistical techniques with unit commitment type studies can be implemented as the experiment progresses. Here a difference between the two utilities may occur. PG&E has a computerized unit commitment logic while SCE uses manual techniques.

During the Initial and Full Implementation Phases, an iterative procedure will have to be added to the pricing calculations to account for the feedback effect of prices on demand and hence on costs. However, such iterations are not needed during the Experimental Phase because too few customers are involved.

Task 4: Specify/Order Communication-Metering Hardware

The purpose of Task 4 is to combine the results of Task 1 (Specify Transactions) and Task 2 (Target Customers) to specify and order the needed communication and metering hardware.

Discussion: Both PG&E and SCE have already installed various types of communications systems which might be used. In the interests of simplicity, for the Experimental Phase it is suggested that the telephone be used as the prime electronic means of communication with radio, etc. used only if desired, for utility-provided control signals.

Customers are provided with demand recording meters which are read manually to compute the actual bills.

Customers are provided with devices which display the appropriate price values obtained by either an automatically customer- or utility-initiated telephone call. Provision is made to provide the prices in digital format for a customer's computer system if so desired.

These display devices are made available to residential customers but installed only if requested.

Spot price implementation for commercial customers is expected to exploit existing GLC and Coop type systems. Obviously already installed hardware could be used or it may be decided to install new systems for new customers. Note that under spot pricing, each member of a GLC or Coop can make its own decisions and receive its own benefits or costs independent of the other members.

Customers receive forecasts of future prices in addition to the spot prices. The methods discussed in Task 5 rely on the mails for communications but an alternate approach would be to install more sophisticated display equipment at the customer's facilities and to make use of telephones.

Task 5: Specify Price Forecasting Services

The purpose of Task 5 is to define the methods used to compute the forecasts of future prices and the procedures by which these forecasts are sent to the customers.

Discussion: The methods used to forecast future spot prices are similar in nature to those used to determine a 24 hour update (in Task 3). However the details can be different (customer service prices forecasts are for longer time ranges and involve less detail).

Two types of price forecasts are:

- A three month forecast mailed to the customers every month which discusses the general outlook and expected ranges of prices that might be seen.

- A one week forecast mailed to be delivered on Monday giving forecasted prices (over eight hour intervals) for the next week and some measure of the uncertainties in the forecast.

It is expected that such forecasts are primarily of interest to the industrial customers but they can also be mailed automatically to all agricultural and commercial customers. They are made available to residential customers if requested.

Customers on 1 hour update are also provided access to the 24 hour update prices which they can use as a measure of the expected value of the prices they will pay.

Instead of relying on the mail, the telephone lines could be used to communicate the forecasts. This increases the cost of the customer's display terminal. If the extra costs could be justified, it would be ideal to have a sophisticated customer terminal so that the customer could choose the format and frequency of the price forecasts.

Task 6: Obtain Regulatory Approval

The purpose of Task 6 is to obtain the approval of the regulatory commission for the 24 hour update and 1 hour update spot price formulae used during the experiment.

Discussion: Any difficulties associated with accomplishment of this task are presently unclear. One potential problem is that regulatory approval is required for a set of formula to be used to set prices rather than numerical values for actual prices. Fortunately, there are precedents already established by the use of fuel adjustment clauses and some of the existing load management and interruptible services presently being offered.

Task 7: Train Utility Representatives

The purpose of Task 7 is to train the utility representatives who are to work with the individual customers to help the customers learn how to respond in a spot pricing environment.

Discussion: Training starts with an intensive course activity during which the utility representatives learn the purpose and structure of the experiment and the methods of response that may be useful to individual customers. The training continues throughout the program. There are periodic workshops in which the representatives interact both with each other and the program management in evaluating the progress of the effort.

Throughout the experiment, a 'hot line' system for customers participating in the program is maintained. This functions--at least through a recording system--around the clock to guarantee that no customer question goes unanswered for more than 12 hours or over a weekend. Training for individuals operating the hot line is required.

Task 8: Design and Implement Operating Center

The purpose of Task 8 is to design and implement the utility operating center which computes the spot prices and forecasts and communicates them to the customers.

Discussion: This control operating center is located in an off-line facility that interferes with the operation of the on-line power system control center as little as possible. Details depend on available facilities and hence are utility specific.

A personal size microcomputer provides enough computing power.

Task 9: Select Customers and Install Hardware

The purpose of Task 9 is to select the actual customers to be involved in the experiment and to install necessary hardware on their facilities.

Discussion: Industrial and commercial customers may already have recording demand meters. New installation may be required for residential and agricultural customers.

Installation of the display terminal inside the customers' premises requires individualized attention by the utility representatives. The existing GLC-COOP machinery is considered by commercial customers.

Input from utility representatives is very helpful in the final selection process.

Task 10: Conduct Experiment

The purpose of Task 10 is to run the operating center.

Discussion: A set of spot price tables that are representative of the price profiles under, say ten, different generic operating conditions is developed. These prestored table values could be sent to the customers during the initial stages of the experiment while the real time system is being implemented. These prestored tables are used when the real time facilities go out of service so that the customers become conditioned to see a reliable stream of price signals. These prestored price tables are used less and less as the system gets debugged.

The operating center needs to be covered 24 hours a day. However, except in times of emergency conditions, this coverage is not a full time task.

As discussed under Task 5, algorithms and methodologies used to forecast future prices become more sophisticated as time evolves.

During the later stages of the experiment, iterative algorithms which address the feedback effect of prices on demand are developed and tested.

Task 11: Customer Reponse Analysis

The purpose of Task 11 is to analyze customer response.

Discussion: Customer response analysis is done using indepth data gathering for individual customers combined with detailed case studies. Three types of studies are:

- o Operational Analysis: Done for all customers. Evalautes how customers could respond to their own benefit with present equipment and facilities.

- o Operational Investment Analysis: Done on a subset of customers. In addition to operational analysis, evaluates possible investments in control decision hardware and/or in new plant facilities to see how the customers might respond over a longer time scale.

- o Generic Modeling: An effort paralleling customer specific case studies. Develops generic model structures and parameterizations applicable to broad classes of customers.

An operational analysis for an industrial customer proceeds as follows:

Step 1: Hold initial discussion to understand nature of processes, costs, and constraints on customer behavior. Involves a detailed tour of plant facilities and discussions with plant operating personnel.

Step 2: Develop formal relationships (in form of equations, tables, etc.) which relate energy consumption to the various process steps, and the costs and constraints of variations in the process. Two key varaibles are energy consumption per person involved in a particular process and the size and type of storage facilities between individual processes.

Step 3: Using the relationships of Step 2, "optimum" behavior which minimizes the customer's electric bill plus the cost occured in rescheduling is evaluated for different types of spot price profiles.

Step 4: The results of Step 3 are given to the customer to help the customer decide actual response behavior.

Step 5: The customer behavior is obtained from the demand meter and by followup discussion with the customer's plant operating personnel.

Step 6: If necessary, the formal relationships developed in Step 2 are modified to reflect the increased knowledge of the customer. Steps 3, 4 and 5 may be repeated several times.

Operational analyses for commerical, agricultural and residental customers proceed in a similar fashion but of course with different emphasis.

Operational investment analysis involves hypothesizing various investments which the customer might make to improve response capabilities. Cost benefit trade-offs are made.

Generic modeling is intended to yield the "building blocks" for an end use type (or physically based type) aggregate model of customer demand with exogenous spot prices (and value of service). This generic modeling is a long term, continuous effort that is not finished during the Experimental Phase (in a sense, it, like all demand modeling/forecasting, is never finished). Generic modeling is not an easy task but much fundamental work is already available. In general, generic modeling of the residential sector is the easiest while the industrial sector is the most difficult.

Task 12: Customer Education

The purpose of Task 12 is for utility representatives to work directly with the customers to help them learn how to respond.

Discussion: This task is closely coupled to Task 7--Train Utility Representatives, and to Task 11--Customer Reponse Analysis. The case studies make use of information gathered during the education process and provide information which is feedback to the customer. Educational material is developed to aid the utility representatives and the residential customers.

Task 13: Evaluate Results

The purpose of Task 13 is to evaluate the results of the experiment.

Discussion: Four questions of concern in the evaluation are:

- o How can customers be expected to respond?

- o How should integration into utility on-line operation be accomplished?
- o What types of rates best meet customers' needs?
- o What type of customer display/control facilities are most effective?

The key question of interest is "How can the customer be expected to respond?" not "How did the customers respond?" Observed customer response based on a customer's desire to be "helpful" and/or customer ignorance of the actual cost incurred due to responding must be ignored. Similarly, a failure to respond because of internal administration inertia, ignorance, etc. must be discounted appropriately.

IV.3 Tasks Preparing for Initial Implementation Phase

Four tasks needed to lay foundations for the Initial Implementation Phase are;

Task 14 Cost Benefit Analysis
Task 15 Value of Service Studies
Task 16 Design Initial Implementation Rates
Task 17 Decide Whether to Proceed

Each of these four tasks are discussed individually.

Task 14: Cost Benefit Analysis

The purpose of Task 14 is to evaluate the trade offs between the metering communication costs associated with different types of transactions and the benefits occurring to the utility and customers.

Discussion: The cost benefit analyses are done using modifications of existing production cost (and possibly generation expansion) programs combined with explicit metering-communications cost data and customer response models. Cost benefit studies start before the customer response analysis of Task 11 is completed by using initial models.

Quantification of quantities such as changes in the utility fuel consumption (and power purchases) is relatively straightforward after the production costs computer codes are modified. Evaluation of capital investment impacts is more delicate and involves a variety of assumptions. Even more subject to uncertainties is the evaluation of the customer benefit.

Many potential benefits are very difficult to numerically quantify. One is the value of customer feedback from spot pricing as a way to deal with potential disruptions in electrical supply caused by oil embargos, nuclear moratoriums, extended dry periods, etc., i.e. to evaluate the value of rationing by price instead of use in rotating blackouts. A second is the improvement in customer equity (cross subsidies reduction) which can result. A third is the potential improvement in utility customer relationships resulting from an environment where customers may develop a better understanding of the utilities' problems and feel that their bills are fairer. All the potential advantages and disadvantages to the power system operator of introducing another control variable (i.e., spot price) into system operation during normal and emergency conditions are also difficult to numerically quantify.

The cost benefit analyses are done for combined price/quantity transactions as well as price only transactions.

Task 15: Value of Service Studies

The purpose of Task 15 is to improve the cost of service models used to determine the quality supply component of the spot price.

Discussion: Customer response analysis (Task 11) provides valuable information for developing value of service models. Furthermore, there are independent studies (at least within PG&E) on evaluating the value of service. Hopefully these efforts provide the information needed to define value of service models satisfactory for use in the Initial Implementation Phase. If not, special efforts are required.

Task 16: Design and Initial Implementation Rates

The purpose of Task 16 is to do the detailed design of the pricing formula to be used in the Initial Implementation Phase and to obtain initial regulatory reaction to these formulae.

Discussion: A more complete menu of spot price based transactions is to be offered during the Initial Implementation Phase. In addition to the 1 hour and 24 hour updated spot prices, 1 month update and quantized level price formulas have to be designed. Combined price/quantity transactions may be included. The issue of customer class cross subsidies is addressed in this task.

Task 17: Decide Whether to Proceed

The purpose of this task is to decide whether to proceed with the Initial Implementation Phase.

Discussion: Conceptually, a decision to proceed with an Initial Implementation Phase requires

- o Regulatory approval of the Initial Implementation Phase rates

- o A positive cost benefit analysis that is "more positive" than alternate methods of proceeding

Unfortunately as discussed in Task 14, cost benefit analyses usually yield a spectrum of quantified, partially quantified, and unquantifiable trade-offs. It is important that Task 17 start relatively early so that time is available to develop the appropriate guidelines and criteria on which the decision will be based. Such considerations could change the nature of some of the other tasks to be done.

IV.4 Research and Development

Most of the Experimental Phase can be classified as research and development. This section briefly discusses additional possible studies of a more fundamental character. No suggestions are made on explicit timing or allocation of resources for such research and development except to state the platitude that fundamental research needs should never be ignored.

Table III.4 summarized research and development needs for all three phases of the overall implementation plan. The following list provides brief elaborations on those efforts listed in Table III.4 that were not covered in Sections IV.2 or IV.3.

Transactions

-Conduct additional theoretical studies on spot pricing algorithms.

-Conduct additional theoretical studies into new methods and techniques for revenue reconciliation.

-Conduct theoretical investigations of price/quantity versus price only transactions.

-Conduct theoretical studies into the nature of cross-subsidies resulting from different types of spot pricing transactions and revenue reconciliation.

-Investigate potential benefits of employing a 5-minute update on large industrial customers, particularly those with their own generation.

Operations

-Investigate problems associated with complete integration of spot pricing into system operations such as unit commitment, security assessment, emergency state control, etc.

Planning

-Incorporate customer price response into corporate financial models.

-Evaluate impact of spot pricing on transmission distribution planning.

-Incorporate impact of spot pricing on uncertainty trade-offs in system planning.

Price Demand Forecast Modeling

-Develop long-range demand models which include price effects.

Metering Communication Hardware/Customer Control

-Repackaging of currently available equipment.

-Continue evolution of the Universal Meter and Control System (UMACS) concept.

Customer Education

-Develop electronic educational aids.

Transmission Distribution Effects

-Investigate the detailed cost/benefit trade-offs associated with different levels of sophistication in implementation of spatial and time-varying transmission distribution effects into spot prices.

Futures Market

-Conduct preliminary evaluation of alternative futures market structures and risk-sharing issues.

Customer Generation

-Investigate the effect of revenue reconciliation on buy-back rates.

-Investigate impact of spot pricing on customer generation potential and desirability.

As discussed in Chapter III, dynamics pricing is a companion concept to spot pricing which is concerned with power system dynamics. Because of the exploratory, long-range nature of research on dynamics pricing, it is highly desirable to pursue this area during the Experimental Phase so the ideas can evolve at a reasonable rate.

IV.5 Project Organization

The Experimental Phase project organization should contain:

- Management Team: Small core of individuals working full-time to maintain day-to-day control.
- Working Group: Staff seconded from different utility departments that could eventually be responsible for or affected by spot prices. Not full-time.
- Analysts, etc.: Individuals doing specific cost/benefit studies, customer response modeling, etc. May or may not be full-time depending on needs.

The Working Group should contain members from different utility departments that are responsible for "Finance;" "Operations;" "Rates;" "Capacity Planning," and "Distribution/Customer Interaction." This Working Group is responsible for day-to-day evaluation of the results and for maintaining two-way communications between the individual utility departments and the Experimental Phase efforts. This Working Group maintains its identity throughout the Experimental Phase. Its function evolves as the effort nears the Initial Implementation Phase when additional members may be required.

Consideration should be given to the establishment of a "Customer Advisory Group" consisting of representatives from industrial, commercial and agricultural trade associations and residential customer advocacy organizations. The involvement of such a group in an advisory role could expedite customer acceptance of spot pricing and provide valuable feedback of potential customer concerns.

A timing diagram for the 17 tasks discussed in Sections IV.2 and IV.3 is given in Figure IV.2

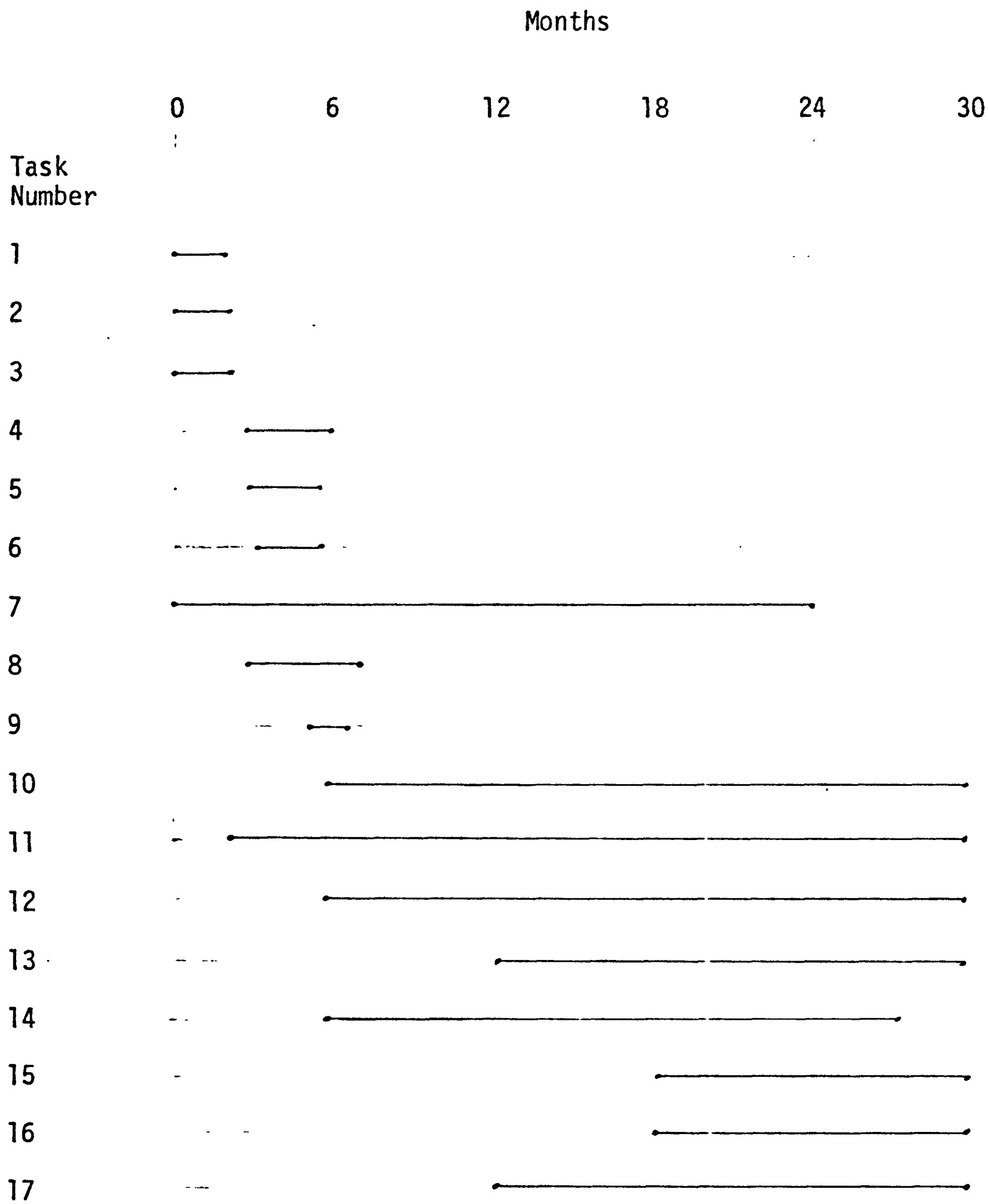


Figure IV.2

Suggested Timing for Tasks
Associated with Experimental Phase

APPENDIX A

HOMEOSTATIC CONTROL FOR ELECTRIC POWER USAGE

This appendix contains a reprint of a paper that appeared in IEEE Spectrum, July, 1982. The paper discusses in a nontechnical way how Homeostatic Control works. The paper provides a general background reading.

Homeostatic Control is a very general approach to power system control, operating and planning which goes beyond the ideas emphasized in the report. Spot pricing using price only transactions is a key component, but Homeostatic Control also includes "microshedding" and "dynamics pricing". Microshedding is a type of combined price/quantity transaction, while dynamics pricing is concerned with power system dynamics.

Homeostatic control for electric power usage

A new scheme for putting the customer in the control loop would exploit microprocessors to deliver energy more efficiently

The law of supply and demand works well with much of the world's commerce. Why not apply this law to consumer purchases of electricity? Improbable though this may seem, extensive advances in computation and communication could allow a modified supply-and-demand electrical system to become operational in a few years. Both utilities and customers would benefit. For utilities, there would be opportunities to cut operating costs and capital investments, and for customers there would be options to buy power at lower rates.

Such a homeostatic control scheme (homeostasis denotes a biological balance of separate functions in an organism) calls for continual updating of electrical rates, based on supply and demand, and continual communication of those rates to customers by the electric utility.

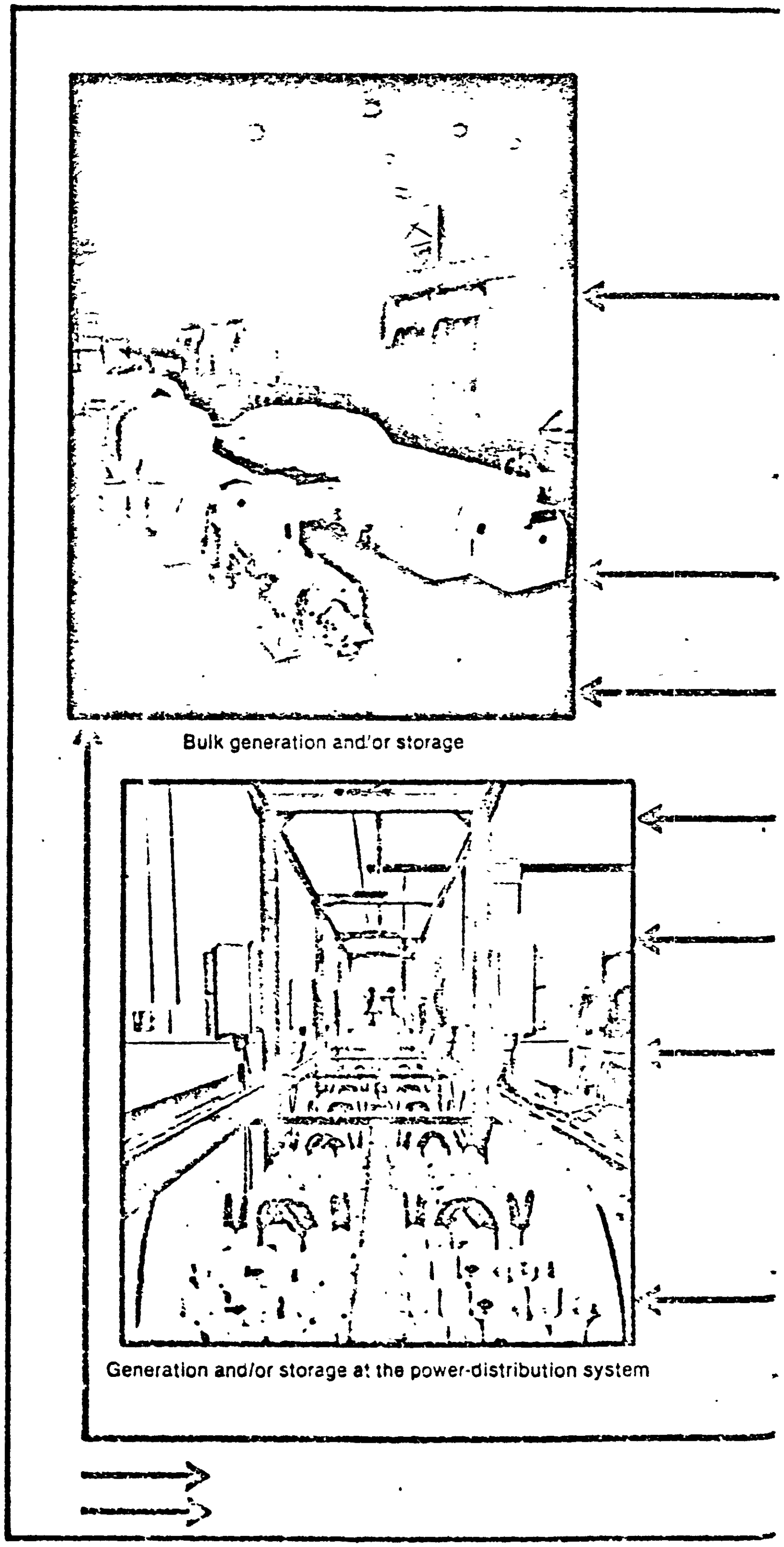
Drawing heavily on today's load-management practices while greatly expanding the scope and nature of utility-customer interactions, homeostatic control would establish a marketplace for electric energy [Fig. 1].

In essence, the scheme would do the following:

- Inform customers of up-to-date variations in rates based on continually changing supply and demand.
- Let customers buy different portions of their electric energy at prices that reflect how reliable the supply is. For example, a supply that is likely to be interrupted often would cost less than a steady—or firm—supply.
- Reward customers who respond favorably during power-system transients, such as a temporary drop in frequency.

Homeostatic control is meant to be implemented gradually. It probably would be used first by industrial customers, then by

Fred C. Schweppe, Richard D. Tabors, and James L. Kirtley
Massachusetts Institute of Technology



[1] Customer independence and communication between electricity customers and utilities are the cornerstones of a future energy marketplace dominated by supply-and-demand rules. Depicted here in an assemblage of photos and artists' sketches, such a marketplace would have a coordinator to dispatch electric energy, similar to the practice in today's energy-distribution and control centers. New faces, however, are the information consultants, who forecast electric energy prices, and energy brokers, who buy and sell long-term contracts for electric energy. Either could come from a regulated utility or an independent company. Photos are by the Consolidated Edison Co. of New York Inc. (top left and right), the Public Service Electric and Gas Co. of Newark, N.J. (bottom left), Arco Solar Inc. of Chatsworth, Calif. (bottom right), and General Electric Co. of Bridgeport, Conn. (inset, bottom right).

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other large users, and finally by many residential customers. Fuel costs and generating-reserve capacity requirements would drop, power-system control during normal operation and emergencies would improve, and customers would be encouraged to install and own their own generating plants, among other benefits.

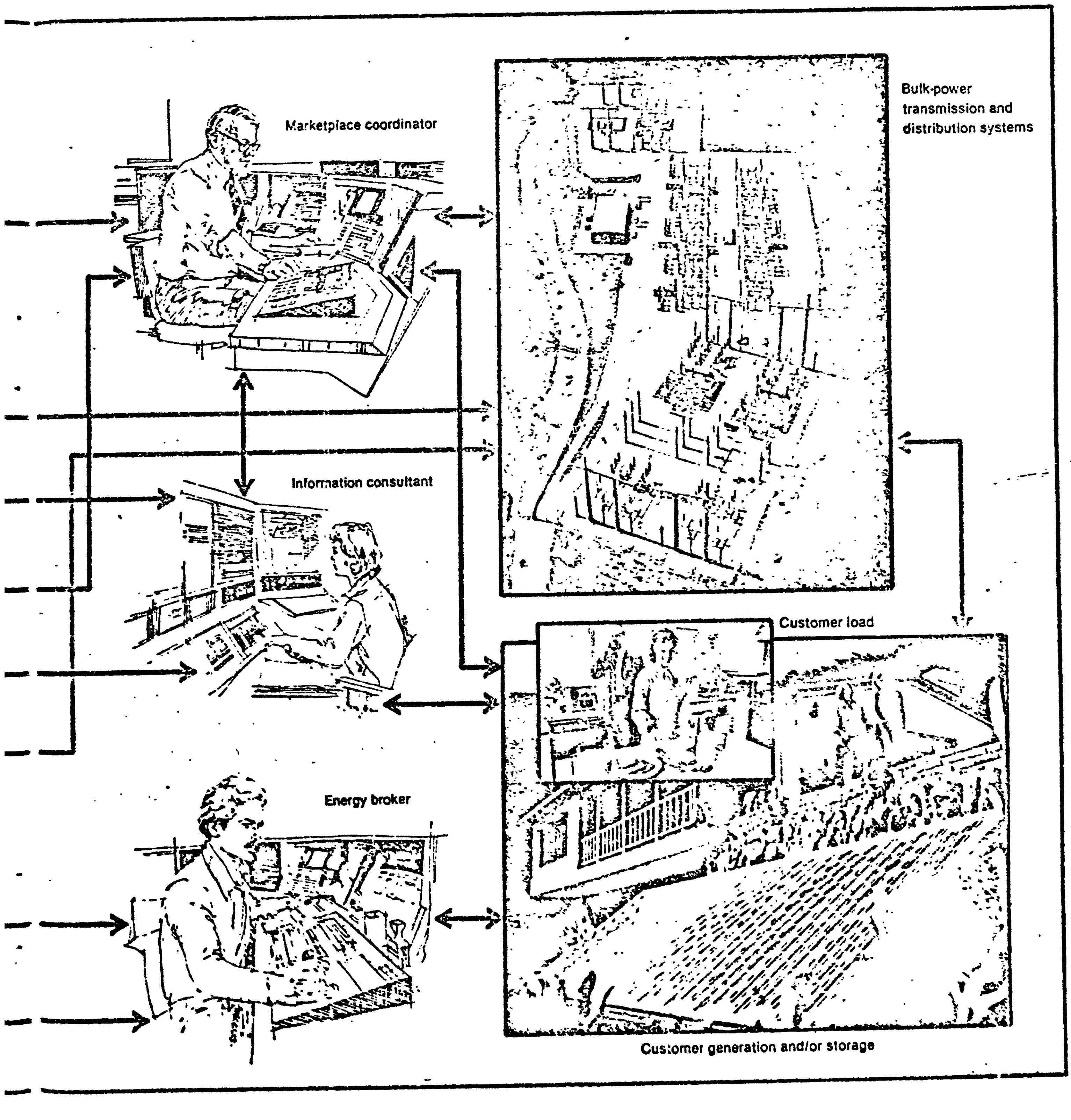
Computation, communication costs falling

Because costs of computation and communication are declining today while electric energy costs are escalating, homeostatic control is timely. It would also open large markets for new microelectronics devices.

A computer simulation, based on data from a medium-size midwestern utility in the United States that uses primarily coal, shows that by allowing the electricity rates for industrial customers to reflect only fluctuating operating costs, a utility could save $1.3 million to $4.7 million each year in operating costs, or 0.5 to 1.6 percent of its annual operating bill. Customer bills would go down in some cases, but up in others.

For the publicly controlled British power system, results reported by Tom Berrie, a consultant in Brighton, England, indicate that such a pricing scheme might, in the long run, reduce the utility's annual total operating and capital costs by about 15 percent.

Much more research, development, and experimentation are



required, however, before homeostatic control concepts could be put into practice.

Three types of transactions envisioned

With homeostatic control, three types of short-term electric energy transactions would be possible:

1. *Spot pricing*—when the rate of real and reactive electric energy varies in response to supply and demand.
2. *Microshedding*—when a customer buys in advance a mix of kilowatt hours, comprising a fixed part that the customer absolutely must have and a cheaper, nonfirm part that is subject to curtailment, or load-shedding.
3. *Dynamics pricing*—when the cost of electric energy reflects the customer's response to a power system stress. The customer would pay less, for example, if consumption were reduced when the frequency fell below 60 hertz and increased when the frequency exceeded 60 Hz.

Spot pricing is based on, first, a utility's capital and marginal operating costs. These marginal costs include fuel, maintenance, and other expenses associated with running the most expensive generator. For example, if at 3 p.m. a utility is running a diesel generator of only 10 megawatts with operating costs of 10 cents per kilowatthour, while its other generators with a total capacity of 10 000 MW are burning coal at 2 ¢/kWh, its marginal operating cost is 10 ¢/kWh. The cost of energy losses is usually small, but it can sometimes exceed 15 percent of the marginal operating cost. Transmission and distribution costs, energy losses, random variations in load, and the availability of generating equipment are also figured into spot prices.

A spot price component reflecting the availability of the supply is added to the marginal operating cost—the less secure the supply, the higher the extra cost. Assume that at 10 a.m. on a summer day peak demand of 12 000 MW is predicted for 3 p.m., while only 10 000 MW is expected to be available at a marginal operating cost of 10 ¢/kWh. The spot price would then be increased beyond 10 ¢/kWh starting at 10 a.m., thereby encouraging customers to reduce demand until it matched the available supply. The spot price increase could range from a few cents to even dollars per kilowatt.

Rates computed by market coordinator

A market coordinator would compute the buying and selling rates for real and reactive energy and transmit them to customers. Rate updating could be done as frequently as each five minutes or once a day. The more frequent updating could be based on today's economic power-dispatch programs, which track systems' marginal fuel and operating costs. Communication links, such as radio, would transmit the rates in real time.

In a 24-hour update, spot prices would be computed once a day for each hour of the next day Here the rates would be based partly on forecasts of generation unit commitments for the next day. A community's daily newspaper could inform customers of the upcoming 24-hour rates.

Other updating frequencies are also possible. One utility might have such a mix of customers as large ones with 5-minute updating, smaller ones with once-a-day updating, and a group with completely fixed rates.

Spot pricing can be viewed as the logical evolution of time-of-use rates. Consider, for example, the midwestern utility mentioned earlier. During one week—Aug. 18-24, 1980—its marginal operating costs varied from about 1.3 to 8.5 cents/kWh [Fig. 2]. Had a sizable supply shortage occurred at the peak price period, the cost addition would have made that peak much higher. It is clear that a predetermined time-of-use rate cannot closely match the cost patterns in Fig. 2. Furthermore, time-of-use rates do not give the utilities enough time to deal with crises, such as unexpected supply shortages.

Customers not interested in saving money could get all the energy they wanted, but generally they could be expected to adjust to spot prices. Consider an industrial plant that uses electricity to melt metal and a residential customer with air conditioning. Under abnormally high spot prices, reflecting a supply shortage, the residential customer might plan to spend the time away from home. The industrial customer might reschedule electric processes to different times or even temporarily reduce production. However, if the industrial customer had a critical order to meet, melting, for example, might continue even at $1/kWh. Similarly, a $1/kWh rate would not deter the residential customer if a wedding were in progress. Fortunately it is unlikely that all industrial customers will have critical orders and that all residential customers will have weddings at the same time.

Ideally, spot pricing is the only tool needed, from both economic and engineering standpoints, to ensure a satisfactory electric energy marketplace. Ideal worlds, however, exist only in the classroom; customers may not always respond by the book.

Direct load control would be possible

To complement spot pricing, various levels of microshedding are possible. In a simple version, the market coordinator releases for publication in daily papers both 24-hourly spot prices for

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A future residential energy-control scenario

7 a.m.
- Computer displays its energy use plan for next 24 hours, based on predicted weather and spot price patterns and on customer's average use, which the computer has learned.
- Owner modifies plan because guests are expected for dinner and to spend the night.

10 a.m.
- Computer receives revised weather forecast and then changes its air-conditioning strategy for the rest of the day.

3 p.m.
- Major storm knocks out many power plants and transmission lines.
- Utility's market coordinator seeks to shed loads. Owner's computer responds by turning off air-conditioning.

3:05 p.m.
- The cost of electricity increases sharply because of equipment knocked out of service by the storm.
- Computer reacts to high prices by turning off everything except the refrigerator, freezer, and itself.
- Owner instructs computer to air-condition the living room starting at 6 p.m., in spite of the very high prices.

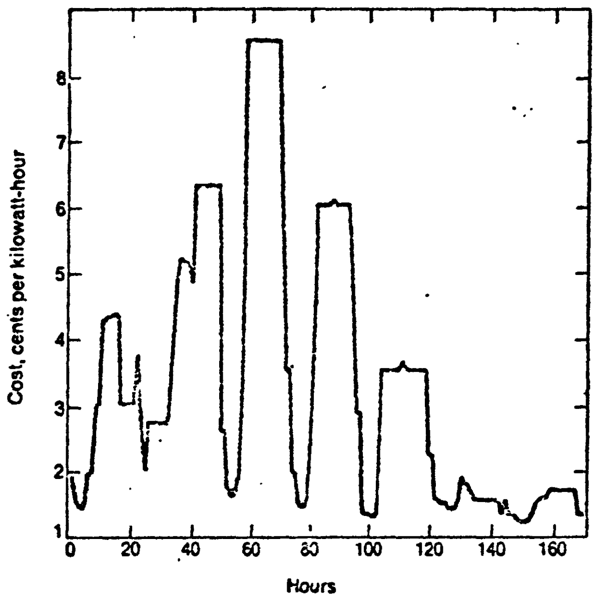
8 p.m.
- Power-system restoration proceeds rapidly.
- Electricity price starts to fall and is predicted to be at a minimum at 3 a.m.
- Owner instructs computer to have guest room and master bedroom air-conditioned by midnight.

12 midnight
- Owner and overnight guests retire.

3 a.m.
- Computer starts to run dishwasher and laundry machines.
- Latest price and weather forecasts cause computer to start cooling parts of the house, so the house can stay cool during the next afternoon.

4 a.m.
- Second storm causes major power system disturbances that result in system frequency swings.
- Computer cycles electrical use in phase with frequency (use drops when frequency drops).

—*F.C.S., R.D.T., and J.L.K.*



[2] In the week of Aug. 18-24, 1980, a midwestern utility saw its marginal operating costs—those associated with the most expensive generating unit in operation—vary over a range of 7 to 1.

firm energy and 24-hour prices for interruptible energy for the next day. In a more complex arrangement, a customer's and a market coordinator's computers renegotiate microshedding contracts every few minutes.

In the simple case, where only x kWh of firm energy every hour are needed, the customer contracts with the market coordinator to buy any energy used over x kWh at a lower, microshedding rate. The market coordinator informs the customer immediately before any load must be curtailed. If the customer violates his contract and uses more than the allowed x kWh, a very large penalty must be paid. The penalty rate and the maximum length of time during which the market coordinator can exercise a microshedding option is specified in the contract.

Dynamics pricing—the third type of transaction—is directed toward even shorter times than microshedding. Two subcategories are possible here. In one, a customer would be charged more or less according to whether the response during a power system stress—say, a frequency drop—would worsen or improve the status of the entire system. In the other case, the customer's equipment characteristics would lead to increases or reductions in his or her electricity rates. If the equipment contributed to a weakening of the entire electricity supply, the customer would be charged more; if it tended to help the system, the electricity rate would drop. For example, customers would be charged extra if their equipment generally contributed to lightly damped power system oscillations.

Both dynamics pricing and microshedding would be continually adapted to prevailing system conditions. A customer would be charged exceptionally high prices if the consumption contributed to transmission-line overloads.

Two-way communication has advantages

While not absolutely essential, two-way communication would be advantageous in the electricity marketplace. Not only would it enhance homeostatic control, but it would also permit remote reading of kilowatthour meters and remote billing and payment. Power and telephone lines, radio, and cable could be the communications media.

A basic principle of homeostatic control is customer independence. The utility should have no direct control over devices and no direct access to the customer's premises. That is—the utility should not "cross the meter line."

An interface between the customer and utility would transmit, measure, and record electric energy use. A simple interface for a 24-hour update spot price, for example, need only measure and record the hourly energy flows for a month on, say, magnetic tape. A utility meter employee could then pick up the tape and take it back to the office, where the month's bill would be computed. Such recording meters are already installed in some industrial facilities.

Data for the control and monitoring of electricity use differs from that transmitted in most local-area data networks. For one thing, the messages are generally shorter, and they may have different levels of urgency. The available bandwidth may be limited, as when a power-line carrier is used. Also, a master-slave type of dialogue is often required, as well as support for multiple, independent systems operating over the same communications network. For example, an air-conditioning control system might share communication links with a lighting control system.

In the belief that ideal local-area data networks to fill these needs are not yet commercially available, MIT has developed for control and monitoring applications a local area network concept called Comonet. This trades computation for communications, in that each of the network ports keeps a complete record of the network state, including the number of stations waiting to use the network.

Transition may be painful

The transition from today's controlled electricity rate system to one dominated by supply and demand rules could be painful to some customers. For example, those who now pay subsidized rates would start paying more and would be likely to complain.

Extension of load management

Homeostatic control has evolved from today's load-management techniques. They include time-of-use rates, simple contracts under which energy can be interrupted upon short notice by the utility, equipment that limits electric demand, and direct load control wherein the utility can turn off specific customer's devices such as water heaters and air conditioners.

Time-of-use rates, however, cannot respond to weather effects, scheduled and unscheduled generation-plant outages, transmission and distribution network emergencies, sudden fuel shortages, and other emergencies.

The possibility of purchasing an adaptable mix of energy comprising a firm and an interruptible part is more flexible with homeostatic control than with today's interruptible energy contracts.

In contrast with load-management practices, homeostatic control includes no fixed-demand charges and requires no demand-limiting equipment because both these techniques may result in consumption patterns that do not reduce operating costs.

Furthermore, direct load control is not incorporated into homeostatic control because it violates the principle of customer independence and places the utility in the untenable position of playing "Big Brother."

—*F.C.S., R.D.T., and J.L.K.*

Electricity customers would have to be educated to take advantage of the opportunities. These transition pains present a larger obstacle to implementation than the actual electric-energy transaction costs themselves.

If many present trends continue, however, the transition could be relatively smooth. For example, utilities are now considering systems for automation and real-time control of power distribution. For the many industrial customers who have already installed energy-management systems, homeostatic control is merely a change in the rules of the game. Residential computer systems are becoming more commonplace. The next generation of customers is already playing electronic games that are more complex than what is needed to put homeostatic control into practice. By the time these future customers become adults, they are likely to consider homeostatic electricity control routine.

Today a residential customer with an energy-control capability such as that depicted in an imaginary scenario [see "A future residential energy-control scenario," p. 46] could not economically justify the system solely for energy control. However, if energy costs continue their upward climb and microelectronics costs continue their downward plunge, it is just a matter of time before that scenario loses its fanciful status.

Homeostatic control would have major effects on the energy systems used by both customers and utilities. Integrated systems containing heat pumps, capabilities for burning two types of fuels, and cogeneration would become more attractive. An industrial complex in which a basic heat source—coal or nuclear—is integrated with a system for generating steam, chemicals, industrial gases, and electricity becomes worthy of consideration. The energy marketplace would encourage renewable generation technologies using solar, wind, or hydroelectric plant sources. Utilities would invest more heavily in efficient baseload generating units. A more robust power system is likely to emerge and planning would be easier, because both the generating systems and the customers would be likely to respond in harmony to unexpected changes in fuel costs, technology, and other factors.

Homeostatic control has social benefits that go beyond economic and engineering efficiency. Customers would become sensitive to the actual costs and problems faced by utilities. Such understanding would encourage better rapport between the two. Today's regulatory process has yielded an extremely complex set of special rates that are confusing to customers and that cause distrust of both utilities and regulatory commissions. The simplifications in the basic rate-making process resulting from spot pricing might prove to be one of its major benefits.

Electric Power Research Institute responds

The industry owes a great deal to the Massachusetts Institute of Technology for a general awakening to the concept that electric utilities should market their products—not marketing in the sense of promoting, but rather as a tool to benefit the utility, its customers, and its owners. This concept is based on the relationship of buyers and sellers operating in a utopian "real time" environment—a relationship brought forward quite explicitly in the accompanying article.

The authors correctly categorize homeostatic control as a tool of load management. The demand-side management used to implement desirable load shape changes has a finite limit. Homeostatic control, however, while theoretically offering the most efficient pricing, is equally limited. The logical next step for homeostatic control involves field demonstrations to test the concept and assess consumer reaction to it.

The true marketplace arrangement will not work until each consumer has several suppliers. Then the decision will be based not only on how much to buy and when, but also from whom.

The uncertainties about homeostatic control are issues of practicality. The authors propose an ideal system to approach economic efficiency. The real questions are: What are the true costs to achieve that efficiency and what are its benefits?

—Clark W. Gellings
Program Manager
Electric Power Research Institute

To probe further

Homeostatic control concepts evolved from ideas in "Power systems 2000," by F.C. Schweppe, *IEEE Spectrum*, July 1978. More background on load management can be found in "Demand-side load management," by C.W. Gellings, *IEEE Spectrum*, December 1981, p. 49.

The mathematical theory of spot pricing is available in "Optimum Spot Pricing: Practice and Theory," by R. Bohn, M. Caramanis, and F. Schweppe, IEEE Power Engineering Society 1982 Winter Meeting, paper no. 82 WM 115-4. The corresponding theory of investment under spot pricing is available in "Investment Decisions and Long-Term Planning under Electric Spot Pricing," by M. Caramanis, IEEE PES 1982 Summer Meeting, paper no. 82 SM 418-2.

For more information on Comonet and customer monitoring and control systems see "Control and Monitoring System Communication for Effective Energy Use," by T. Sterling, R. Williams, and J. Kirtley, IEEE PES 1981 Summer Meeting, paper no. 81 SM 307-8.

"Space Conditioning Load under Spot or Time of Day Pricing," by P. O'Rourke and F. Schweppe, IEEE PES Summer 1982 Meeting, paper no. 82 SM 433-1, develops simple formulas to evaluate savings-discomfort tradeoffs for air-conditioning under spot pricing.

An analysis of the benefits of spot pricing for the entire British power system was done by T. Berrie and is reported in "Interactive Load Control: Parts 1 through 6," *Electrical Review*, 1981-82, Quadrant House, Sutton Surrey, England.

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APPENDIX B

SPOT PRICING LITERATURE REVIEW AND REFERENCES

APPENDIX B

SPOT PRICING LITERATURE REVIEW AND REFERENCES

This Appendix provides a discussion of the available literature related to spot pricing. The appendix itself has been adapted from Bohn [1982].

B.1 General Background

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 a number of utilities in the U.S. and Europe.

- o 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].

- o Florida has a power broker system which systematically communicates energy prices between utilities at individual bus points in the Florida grid system. This is spot pricing with spatial (transmission) differentiation between utilities in the system [Cohen, 1982].

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.

B.2 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:

- Generating unit availability is practically ignored or modeled by simply derating unit sizes at all times. This fails to penalize properly large units, and it gives wrong 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.

- 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.

- 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 assume 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 state contingent prices. 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.

B.3 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.

B.4 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.

Scherer has the best model of electricity line losses and line constraints, and includes T&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.

B.5 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].)

B.6 Spot Pricing

Spot pricing of public utility services was apparently 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, 1978 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, Bohn 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.

- "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 <u>ex post</u>, 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 restraints 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.

A series of articles on spot pricing and Interactive Load Control appeared in <u>Electric Review</u> in 1981 and 1982 [Berrie, 1981/82].

The Credit and Load Management System (CALMS) is an important system and hardware development in England [Peddie, 1982a, 1982b] which has major implications for spot pricing. The key component, the Credit and Load Management Unit (CALMU) is a microprocessor-based metering control and display system designed for residential use. A new version presently being designed can accept a spot price data stream. It is closely related to the Universal Metering and Control System (UMACS) discussed in Chapter III.

Chemical Week [Sept. 29, 1982, pp. 66-67] discusses spot pricing from the chemical industry customer's point of view. This article mentions other spot pricing efforts under way in Europe.

Finally, there are the most recent articles from MIT on spot pricing [Bohn, 1982; Bohn et al, 1981] which show the structural advantages of spot pricing, and Caramanis [1982] which evaluates the investment implications of spot pricing. An analysis of spot pricing in Wisconsin [Caramanis, Tabors et al., 1982] showed the customer and utility benefits given operation of a single utility.

Extensions of Spot Pricing ideas into broader utility issues such as Deregulation have also been carried out by the MIT group [Bohn et al., 1981; Golub et al., 1982, Bohn et al., 1982. These analyses have discussed the structural use of full spot pricing for deregulation of generation which includes both the customer and the utility working within an energy marketplace.

B.7 Annotated List of MIT Reports, Papers

Many reports and papers have been written at MIT that are related to spot pricing. The following is an annotated list. Many of the following were discussed above but the list provides a self-contained description of available MIT efforts. Spot pricing is one part of a larger overall approach to electric power systems called Homeostatic Control, so there are many references to Homeostatic Control.

The list is separated into three areas

- o Spot pricing and Homeostatic Control
- o Work on customer demand modeling related to spot pricing.
- o Approaches to deregulation based on spot pricing.

The following cover spot pricing and Homeostatic Control:

"Power Systems 2000" by Fred C. Schweppe, IEEE Spectrum, Volume 15, Number 7, July 1978. 6 pages. An informal discussion of how a decentralized state-of-the-art power system could work using spot pricing.

"New Electric Utility Management and Control Systems: Proceedings of Conference" by the Homeostatic Control Study

Group, June 1979, 200 pages, MIT-EL 79-024. Discussion papers and audience reaction from a conference on homeostatic control.

"Industrial Repsonse to Spot Electricity Prices: Some Empirical Evidence," by R. Bohn, February 1980, MIT-EL-80-016WP, 30 pages. An econometric examination of 3 industrial customers in the U.S. which are on a weak form of spot pricing. Detailed statistics, but no discussion of what customers did to allow them to respond.

"Homeostatic Utility Control", by F. Schweppe, R. Tabors, J. Kirtley, H. Outhred, F. Pickel and A. Cox, IEEE PAS-99 No. 3, May/June 1980, 9 pages. A complete and relatively concise presentation of homeostatic control's main elements. A few equations, but no formal derivations.

"Quality of Supply Pricing for Electric Power Systems" by H. Outhred and F.C. Schweppe, IEEE Summer Power Meeting, July 1980, paper A80 084-4, 5 pages. An intuitive exploration of the quality of supply aspects of spot pricing. No equations. Following reference develops the same concepts rigorously.

"Optimal Spot Pricing of Electricity: Theory" by R. Bohn, M. Caramanis and F. Schweppe, March 1981, MIT-EL 81-008WP, 100 pages. Formally derives optimal spot prices and optimal investment under spot pricing. Mentions some regulatory issues but does not discuss them. Many equations; no numerical examples.

"Optimal Spot Pricing: Practice and "Theory," IEEE PAS Vol. PAS 101 No. 9, Sept. 1982, by M. Caramanis, R. Bohn and F. Schweppe, 12 pages. A paper based on above reference written for engineering audience.

"Investment Decisions and Long-Term Planning Under Electricity Spot Pricing," by M. Caramanis, IEEE PAS, Vol. PAS 101 No. 12, Dec. 1982, 9 pages. More details and extension of above in investment areas.

"Utility Spot Pricing Study: Wisconsin," by M. Caramanis, R. Tabors and R. Stevenson, MIT Energy Laboratory, June 1982, 200 pages. A case study simulating benefits and their distribution associated with spot pricing of industrial customers in a Wisconsin, U.S. utility.

"Spot Pricing of Public Utility Services," by Roger Bohn, unpublished PhD thesis, MIT, Sloan School of Management, Cambridge, May 1982. Also Technical Report MIT-EL 82-031, 200 pages. A general and comprehensive treatment of economic issues related to spot pricing of public utility services including investment and operational issues, from the utility, societal, and customer perspectives. A generic customer response model/framework is also developed.

"Homeostatic Control for Electric Power Usage," by F. Schweppe, R. Tabors and J. Kirtley, IEEE Spectrum, July 1982, pp. 44-48 (5 pages). An informal discussion of how Homeostatic Control and spot pricing works.

"Optimal Pricing of Public Utility Services Sold Through Networks," by R. Bohn, M. Caramanis and F. Schweppe, Graduate School of Business, Harvard University, HBS 83-21, 97 pages). Detailed discussion on impact of transmission distribution networks in spatial dependence of spot prices. Discusses properties of optimal wheeling charges.

Customer demand and value of service modeling is crucial to the spot pricing concept. Many of the following do not address explicitly spot pricing but contribute to the development of a solid foundation for physically based, end use modeling.

"Space Conditioning Load Under Spot or Time of Day pricing," by P. O'Rourke and F. Schweppe, IEEE PAS, forthcoming, 1982 Summer Power Meeting, 9 pages. Develops simple to use formulae to evaluate savings-discomfort trade-offs for space conditioning under spot pricing.

"A Theoretical Analysis of Customer Response to Rapidly Changing Electricity Prices", by R. Bohn, 1980, revised January 1981, MIT-EL-81-001WP, 150 pages. A series of models of electricity use, emphasizing the response of profit-maximizing customers to spot prices. Derives the increase in customer profits from various forms of spot pricing. Some discussion of actual case studies, but no real-life numerical examples.

"A Weather Dependent Probabilistic Model for Short Term Load Forecasting," by F. Galiana and F. Schweppe, IEEE PAS Winter Power Meeting, N.Y., (C72-171-2), 1972, 7 pages. Discusses an hour by hour 1 week forecasting model of aggregate demand for use in operational control centers.

<u>Electric Load Modeling</u> by James Woodard, Garland Press, N.Y., 1979, 350 pages. Provides a deterministic framework for physically based end use modeling of electrical demand with emphasis on the residential sector.

"Physically Based Load Modeling" by Y. Manichaikul, J. Woodard, and F. Schweppe, 1978 IEEE Summer Power Meeting, paper No. F78 518-3, 8 pages. Provides a stochastic framework for end use modeling.

"Physically Based Industrial Electric Load" by Y. Manichaikul and F. Schweppe, <u>IEEE Trans. on Power Apparatus and Systems, Vol. PAS-99, No. 2, March/April 1980</u>, 7 pages. Application of the stochastic framework to the industrial sector by individual case studies of seven specific customers.

"Physical/Economic Analysis of Industrial Demand" by Y. Manichaikul and F.C. Schweppe, IEEE Transactions on Power Apparatus and Systems (PAS) Volume PAS 99, Number 2, March/April 1980, 7 pages. Models loads as random processes. Does not explicitly model effect of changes in electric rates, but suggests how to estimate these effects. Based on seven specific case studies.

"Physically Based Modeling of Cold Load Pickup" by S. Ihara and F. Schweppe, IEEE Trans. on Power Apparatus and Systems, Vol. PAS-100, No. 9, September 1981, 9 pages. Application of stochastic strutures to modeling load level response to short interruptions.

"Electric Load Management by Consumers Facing a Variable Price of Electricity" by P. Constantopoulos, R.C. Larson and F. Schweppe, 1982 Joint National Meeting, San Diego, California, October 26, 1982, 30 pages. General discussion of a theoretical framework for analyzing customer response to spot prices.

Spot pricing and Homeostatic Control were developed for regulated utilities. However, the ideas provide a sound basis for partial or full deregulation of electric utilities if that is desired. The following are articles focusing on the deregulation area.

"Deregulating the Electric Utility Induustry," by R. Bohn et al. [1981], MIT Energy Laboratory Technical Report MIT-EL 82-003.

"Using Spot Pricing to Partially Deregulate Utilities, Customers and Generators," by R. Bohn, F. Schweppe and M. Caramanis. Presented at the NARUC Conference, Columbus, Ohio, Sept. 10, 1982, 11 pages.

"An Approach for Deregulating the Generation of Electricity" by B. Golub et al., forthcoming in Electric Power Strategic Issues: Deregulation and Diversification, edited by S. Plummer, T. Ferrar and W. Hughes.

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APPENDIX C

SPOT PRICING THEORY

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SPOT PRICING THEORY

This Appendix presents a concise mathematical discussion of optimal spot prices, proposes a practical way for setting spot price based rates, discusses investment and revenue reconciliation issues, outlines three alternate formulations and discusses questions associated with the impact of spot pricing on variability, stability and uncertainty. It is included in support of Chapter II. Even more detailed discussions can be found in the references of Appendix B.

C1. Operational Determination

Social welfare optimization implies, in the absence of communication, metering and transactions costs, an optimum "instantaneous spot price" S(t) defined by

$$S(t) = \begin{cases} \lambda(t) \quad \text{if} \quad v(t) > 0 \qquad (\$/\text{KWH}) \\ \text{market clearing price subject to} \\ \text{ceiling otherwise} \end{cases} \qquad (C1)$$

where:

$v(t) = g(t) - d(t, \lambda(t))$: the reserves available at time t

$g(t)$: maximum generation available at time t

$d(t, \lambda(t))$: the actual demand at time t if customers see a price equal to $\lambda(t)$

$$\lambda(t) = \frac{\Delta[\text{variable generating costs over unit commitment period}]}{\Delta[g(t) - v(t)]}$$

: related but not always identical to system lambda used in economic dispatch

The market clearing price is obtained by adding a non-zero "quality of supply" component to $\lambda(t)$ to reflect the fact that available generation is binding.

The use of the instantaneous spot price is not practical. Define

$p(t/t_o)$: Spot price based rates, set and posted at time (t_o) preceding the time they come into effect (t).

Such rates are related to the instantaneous spot price by the formula

$$p(t/t_o) = E_{t_o} S(t) + \text{correlation term} \quad (\$/KWH) \quad (C2)$$

where:

E_{t_o} : expectation operator corresponding to the probability density function of random variable realizations at t as determined at t_o

t_o: time when price is determined

t: time when price comes into effect

Correlation Term:

A term depending on the covariance of customer demand response to price and the instantaneous spot price. Although it may generally be positive or negative it is close to zero when t_o is close to t (by a day or even a week). It will thus be assumed to be zero for the rest of this discussion.

Comparing equations C1 and C2 one observes that the market clearing price level is yet undefined. Although there are alternative ways for this estimation we propose here a practical approach that could be determined in advance of and verified after utility action is taken in conjunction with a generating capacity shortfall.

Define

$P(v(t)/t_o)$: conditional probability density of reserve margin at t as determined at time t_o.

Then

$$p(t/t_o) = \int_{v=o}^{\infty} \lambda(t/t_o)\, P(v(t)/t_o)dv + \int_{-\infty}^{o} D^{-1}[d(t,\lambda(t)) - v(t)]P(v(t)/t_o)dv \quad (C3)$$

where

D^{-1}: The value of service model. This is the inverse demand function representing the value to customers of additional energy usage or the cost of an incremental curtailment in energy usage. The inverse demand curve for a particular group of customers under the spot price based rate is defined such that it does not exceed a ceiling representing the cost of service curtailment to customers that are not covered by this rate.

To illustrate the approach, assume that the conditional probability distribution of $v(t)$ is normal with mean $\hat{v}(t/t_o)$ the best estimate of $v(t)$ at t_o and variance $\sigma^2(t/t_o)$ which is usually an increasing function of the advanced notice time $t-t_o$. Thus the price estimate becomes

$$p(t/t_o)=\lambda(t/t_o)(1-q)+ qf[\hat{v}(t/t_o),\sigma(t/t_o)] \qquad \text{(C4)}$$

where

$$q = \int_{-\infty}^{0} P(v(t)/t_o)dv; \text{ the loss of load probability and}$$

f: A function reflecting customer demand response and the price ceiling established on the market clearing price.

The price ceiling is determined by the cost of quantity rationing (rotating blackouts or demand curtailment priorities) applicable to customers not covered by spot pricing. The mathematical theory shows that the optimal spot price should not exceed the value of service (cost of interruption) incurred by customers not under spot pricing. A set of priorities discussed and decided upon apriori to capacity shortfalls could be easily incorporated into a formula determining spot price levels and implemented at actual times of shortfalls in an integrated price and quantity rationing scheme. The quantity rationing scheme should be reflected in the prediction and probability distribution function of reserve margin realization $v(t/t_o)$ in equation (C4).

Discontinuities in the spot price at time of sufficient generating capacity availability may arise at times a significantly more expensive fuel source (peaking gas turbine for example) is about to be brought on line or an expensive tie-line purchase is the only source available for meeting incremental demand. In these cases the system marginal variable cost may be discontinuous and undefined except for an upper and lower bound of permissible values. This indefiniteness can be resolved by using the inverse demand function defined above to determine the actual price within the two bounds that maximizes demand subject to not resorting to the more expensive source of supply characterizing the upper bound. Figure C1 elaborates this visually.

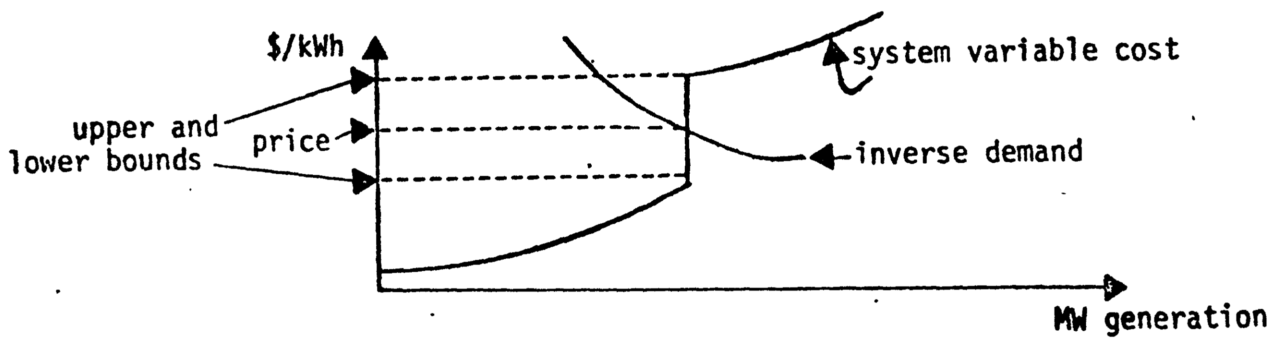


Figure C1

Spot Price Determination with a Discontinuous Marginal Cost Curve

Finally, the intertemporal price effects should also be considered to account for demand rescheduling. This can be done by considering a vector demand function relating a trajectory of demands to a trajectory of prices defined over a relevant cycle length (day or week).

C2. Investment Under Spot Pricing

Although optimum spot pricing is based on short-term marginal costs it allows for net revenue (over and above variable costs) to cover investment and fixed O&M costs by generators, consumers and the T&D network. A generator realizes such net revenues whenever the spot price exceeds its variable operating costs. Figure C2 exemplifies this by showing the energy generated by a particular unit (proportional to areas A plus B) using the concept of the Equivalent Load Duration Curve (ELDC). The ELDC reflects demand seen in a probabilistic sense by a particular generator, taking into account customer load, generation by less fuel-expensive generators and forced outages of these generators. While the generator makes no profit when it is on the margin (energy produced without profit is proportional to area B), it realizes net revenues when a more fuel-expensive generator is on the margin (energy produced with profit is proportional to area A). These net revenues can be estimated in advance if future spot prices can be forecast in a probabilistic sense.

State-of-the-art capacity expansion planning for

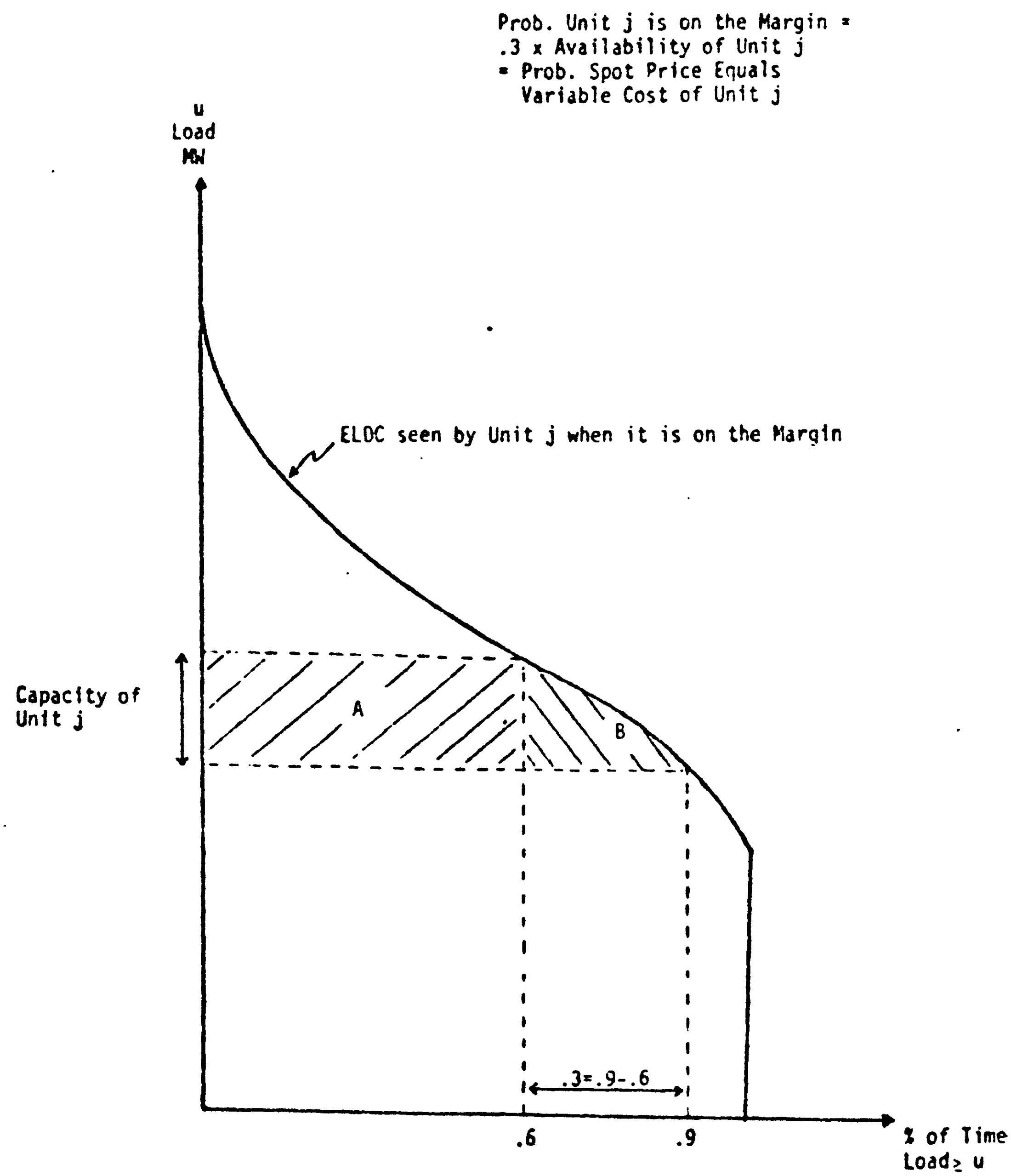


Figure C2. Spot Price When Unit j is on the Margin electricity generation uses well-established probabilistic algorithms and models which yield reliable estimates of the expected variable costs of generation over a future period. These estimates are obtained as a function of demand and generation uncertainties described by probability distributions. The same algorithms can be extended to yield estimates of the spot price probability distribution. Figure C3 presents an example of such a probability distribution expressed in terms of a price duration curve. The price duration curve can serve as a means of forecasting the profitability of a particular generation technology in a similar fashion to the use of expected operating costs in present long-term planning practice. Optimal composition of the generating stock is achieved when investments are undertaken so that net revenues over every generator's service life suffice to cover fixed O+M and investment costs. Figure C3 shows that even peaking units, which are the most expensive in terms of variable costs, realize net revenues when total generation is binding.

Generating units also provide spinning reserves and/or impose requirements for spinning reserves. This spinning reserve issue has not been handled in the present discussion but it can be factored in to account for additional charges and revenues accruing to generators and consumers for their effect on spinning reserve requirements. Proper reflection of spinning reserve requirements in the spot price results in additional revenues for peaking units.

C3. Revenue Reconciliation

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.

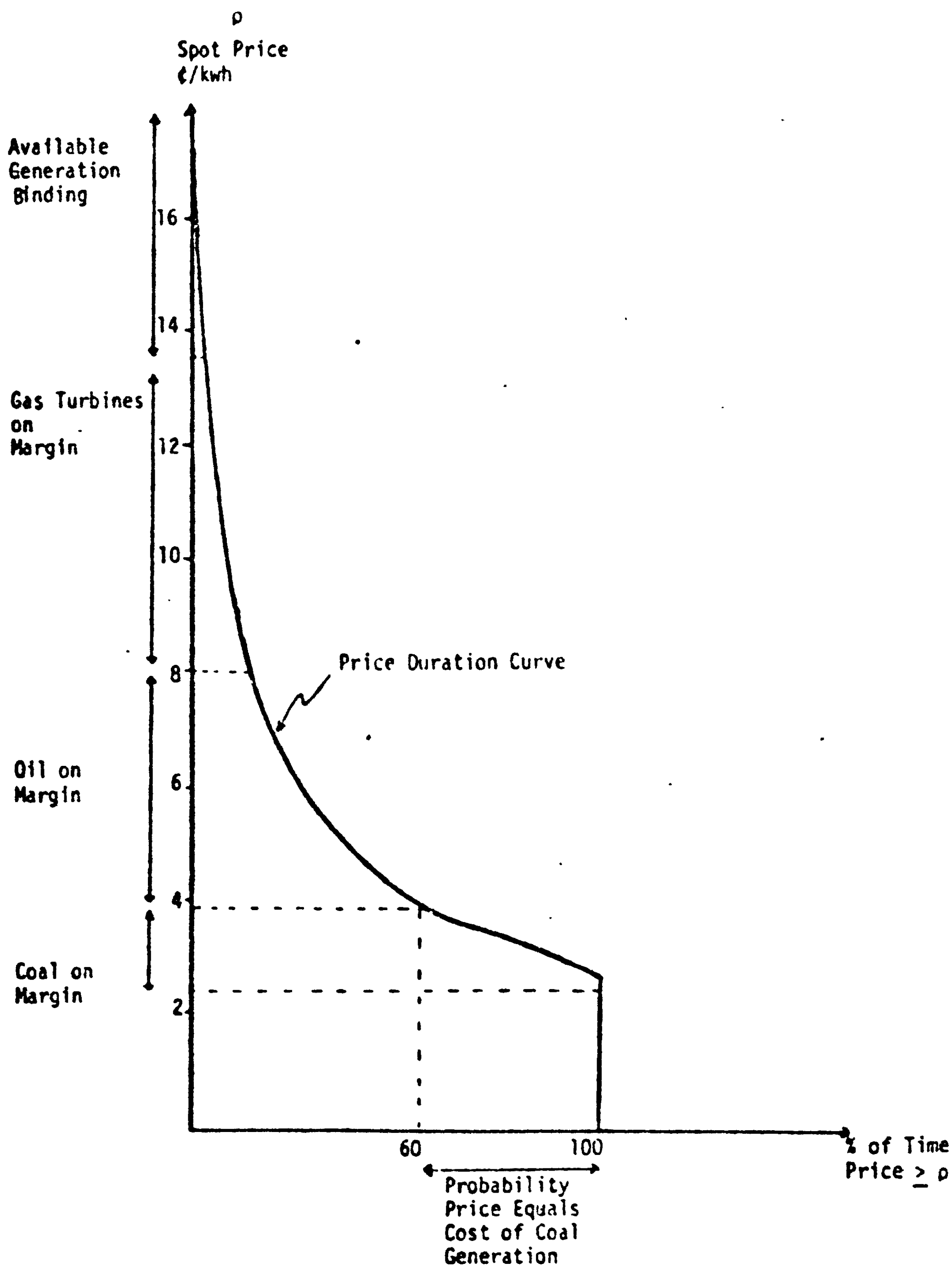


Figure C3. The Price Duration Curve

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 (see reference in Appendix B) considered the problem of financing public works such as bridges where the marginal cost of crossings is 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 elasticities 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. In the near term, 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.

The above general discussion of the revenue reconciliation issue is provided as a summary of the prevailing views in the economic literature. This report does not recommend any specific approach to revenue reconciliation. Revenue reconciliation decisions should be subject to the special conditions characterizing the utility system involved and the prevailing regulatory philosophy incorporating social, political and other economic considerations.

C4. Alternative Formulations

Spot pricing can be viewed as the result of the following three-step process:

- A value function which evaluates the behavior of the utility (generators, etc.) and the customers is specified along with the various constraints that are to be met.

- Mathematical optimization theory is used to specify particular behaviors (of the utility and customers) which maximize the value function subject to the constraints.

- A pricing scheme (i.e., spot pricing) is developed to encourage these optimum customer behaviors.

The basic spot price formulation (as discussed in the previous sections) uses a value function which is the sum, over many years, of the value of electricity used by the customers minus the fuel and operating costs of the generators minus the capital costs of both the utility's and customer's equipment. This basic formulation yields what might be called a "pure short-run marginal cost" pricing system. Three alternative formulations will now be discussed:

- Environmental dispatch
- Allocation of primary fuel resources
- Long-run marginal cost.

Southern California Edison dispatches its power plants to minimize total NO_x discharge rather than operating costs. Relative to the spot pricing, this implies a change in the value function evaluating generator behavior to "internalize" social costs of NO_x discharge. Hence the resulting spot prices are not the "pure short-run marginal cost" prices of the basic formulation. However, the value of spot pricing as a method of providing improved feedback between the utility and its customers and encouraging desirable customer behavior remains unchanged.

A second alternative formulation occurs when a social-political decision has been made relative to the allocation of primary fuel resources such that the utility sees a higher price for one of its primary fuel sources (e.g., natural gas) than some of its customers. Under such a situation, the spot prices those customers see for electricity are no longer "economically correct" in a strict sense. However the value of spot pricing per se relative to other methods of rate and load management techniques remains unchanged.

A third possible alternative formulation assumes it is desired to implement spot pricing under a long-run marginal cost pricing philosophy. As background, consider first the difference between long-run marginal costing (LRMC) and short-run marginal costing (SRMC) in the conventional non-spot price framework when prices are prespecified well in advance (before plant outages, other demand patterns, etc. are realized). In such a context, SRMC attributes to a perturbation in demand the short-run (operational only) marginal costs plus the cost of incremental unserved energy caused by the demand perturbation while LRMC attributes to a perturbation in demand the total cost difference (capital plus operating) of two optimal expansion plans corresponding to the original and perturbed demands. The optimal expansion plans are obtained by minimizing the cost of serving demand over a planning period subject to constraints (usually probabilistic) on the reliability with which demand is serviced. The two methods can be shown to yield the same expected value of marginal costs, under optimal investment and compatible cost of unserved energy assumptions. The LRMC approach includes an implicit cost of unserved energy introduced through the shadow price (Lagrange multiplier) associated with the service reliability constraint. If the service reliability constraints in the LRMC approach are set at the levels that yield a shadow price equal to the cost of incremental unserved energy (rationing) employed in the SRMC approach, then the results of the SRMC and LRMC methods can be shown to be equivalent provided the existing system is "optimal." In practice, of course, the existing system is rarely "optimal" and the two approaches can yield different prices.

Now consider SRMC or LRMC philosophies in a spot pricing context. As already discussed, the basic spot price formulation can be viewed as "pure SRMC" pricing. It is conceivable that an alternative spot price formulation could be developed by changing the value function or constraints to yield spot prices which are closer to a long-run marginal costing philosophy. We, however, have not explored this path and it is a subject for future research.

The key point of the preceding discussion is that the application of spot pricing is not rigidly tied to any particular problem formulation (choice of value function and quantification of constraints). Spot pricing is a way to encourage "customer behavior" which optimizes a particular performance criterion where there is freedom in the definition of the performance criterion.

C5. Variability, Stability, and Uncertainty

Spot prices vary with changes in system conditions and cause subsequent changes in demand, etc. This gives rise to concern about quantities such as:

Variability: Measure of the amount of change over time of some function or variable such as price or demand.

Stability: Measure of the smoothness of response of a system's output when its input is perturbed; e.g., the response of spot price over time following the unexpected outage of a major generation facility.

Uncertainty: Measure of the inaccuracy associated with predictions of the future behavior of a time function or of the nature of a system's response.

Before discussing such quantities, it is important to clarify their definitions and interpretations. A time function's variability and uncertainty are independent concepts. For example, a clock exhibits a lot of variability over a day but very little uncertainty, while the amount of snow on the ground on Christmas day in Boston exhibits a lot of uncertainty (when predicted a year in advance) but usually varies little during the course of the day. In a similar fashion, an input-output system's stability and uncertainty are independent concepts. A system may be very stable even if there is a lot of uncertainty in predicting its response while one might be able to predict with great certainty that a system is unstable. The output of a system is a time function whose variability and uncertainty are determined by both the system itself and the system's inputs. For example, a time variable and uncertain output could be obtained from a stable, certain system with a time variable, uncertain input or from an unstable, uncertain system with constant, certain inputs. Finally, uncertainty in the nature of a system's response can arise in two ways.

Inherent System Uncertainty: The nature of the system's response changes over time in a non-perfectly predictable fashion; i.e., a different response to the same input at different times.

System Model Uncertainty: The system's response itself is certain but not enough studies have been done to understand it; i.e., there is modeling uncertainty.

The discussions to follow are based on Figure C.4. Four input-output systems whose stability and uncertainty are to be discussed are:

Utility Response: One component of Figure C.4
Customer Response: Another component of Figure C.4
TOU Pricing: "Open Loop" Figure C.4 (switch down)
Spot Pricing: "Closed Loop" Figure C.4 (switch up)

It is necessary to discuss the components of Figure C.4 before considering the complete systems of real concern.

Utility Response System: The utility's response to external inputs and demand is well understood. It is a stable system with little uncertainty of either the inherent or modeling type.

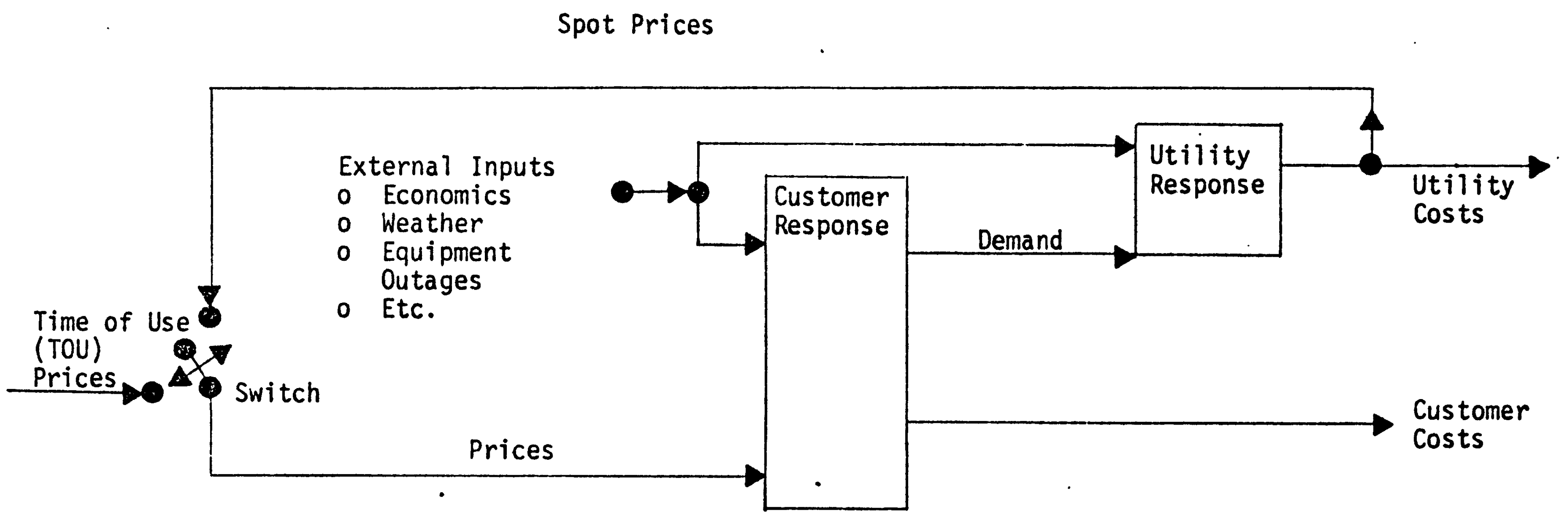
Customer Response System: Two types of customer response are:

Individual response of one customer
Aggregate response of many customers.

Individual customer response has a lot of uncertainty of both types. Aggregate customer response to external inputs is stable with little uncertainty of either type. Aggregate customer response to TOU prices is stable with little inherent uncertainty and a level of modeling uncertainty that has been decreasing rapidly in recent years. Aggregate customer response to spot prices presently has a lot of modeling uncertainty. Some modeling research is under way but much remains to be done. However, the research that has been done indicates that the inherent uncertainty and stability of aggregate customer response to spot prices is similar to aggregate response to TOU prices. The subsequent discussions assume that the necessary research has been done so the modeling uncertainty of aggregate customer response to spot and TOU prices is equivalent.

TOU Pricing System: This is the open loop version of Figure C.4 (switch down). The system is stable (hours to days) with uncertainty of both types determined primarily by the aggregate customer response.

Spot Pricing System: This is the closed loop feedback version of Figure C.4 (switch up). It is well known that inappropriate feedback can cause system instability and can magnify the effect of uncertainties in the system and/or the system's input on its output. On the other hand, correctly



o Switch Down

o TOU Prices
o Open Loop

o Switch Up

o Spot Pricing
o Closed Loop

Figure C.4

Comparison of TOU and Spot Pricing Systems designed feedback is one of the primary tools for developing stable systems whose response uncertainty due to both open loop uncertainty and input uncertainty is greatly reduced. Initial studies done on the dynamics of the spot price closed loop feedback system have not uncovered any reasons to believe that simple spot price feedback will cause instability or uncertainty magnification. On the contrary, it presently appears that simple spot price feedback will provide the desirable properties of reduced sensitivity to system uncertainties and input perturbations. However if subsequent analyses uncover a problem, compensating logics for the spot price feedback signals can be added as needed. The design of such compensating logic does not require a certain model for aggregate customer response to spot price. Because of the feedback, some modeling uncertainty can be handled as an integral part of the design process.

The discussions now turn to four time functions which are outputs of the systems of Figure C.4:

- o Utility costs (hourly to days)
- o Spot prices (hourly to days)
- o Annual individual customer costs
- o Annual utility net revenues/profits

Interest centers on the relative inputs of TOU and Spot Pricing on the time variability and uncertainty in these time foundations.

Utility Costs: Correctly designed spot price feedback reduces both the time variability and uncertainty in hourly to daily utility operating costs relative to TOU pricing. As just one example, consider the case where a major generation plant outage occurs. With open loop TOU pricing, customer demand remains unchanged so operating costs rise directly proportional to the cost of the more expensive generation brought on line or purchased. With spot pricing feedback, reduction in customer demand reduces the change in utility operating costs.

Spot Prices: Hourly to daily spot prices exhibit more uncertainty than TOU prices. However the key concern of an individual customer is not the uncertainty in the spot prices but rather the uncertainty in total costs over say a year. Annual costs for an individual customer are discussed below. Now consider the time variability of TOU and spot prices. For example, if one looked over a one year history, one might discover that the prices behaved as follows:

Time of Use Prices: Three medium sized jumps each day with pattern changes on weekends and with seasons.

Spot Price: During most of the year, small one hour perturbations (much smaller than TOU jumps). During a few times of system stress, large variations (much larger than TOU jumps).

The question of which history exhibited more time variability depends on one's criteria.

Annual Individual Customer Costs: Define
Annual Individual Customer Cost = (Annual Electricity Bill) + (Cost to Customer of Unscheduled Outages) - (Value to Customer of Electricity Used).

Consider first the uncertainty in predicting this quantity one year in advance. A particular customers faces more uncertainty in predicting his/her annual bill under spot pricing than under TOU pricing (saving fuel adjustment charges which could change to the statement). However the TOU/Spot relationship is much less clear for total annual costs. Consider a system that has a sizeable probability of generation shortages with a need for rotating blackouts under TOU. The uncertainty an individual customer faces as a result of the probability of a single blackout can be greater than the uncertainty in the annual bill due to spot pricing. If a customer exercises control and responds to spot prices, the uncertainty in both his/her annual bill and the value of electricity used may be reduced. Now consider the time variability of an individual customer's annual cost over multiple years. This time variability will be dominated by the behavior of external variables such as the national economy, the price of oil, development of new generation technologies, etc. Any extra difference between TOU and spot prices is expected to be small (assuming equivalent revenue reconciliation is used).

Annual Utility Net Revenues/Profits: The annual utility net revenue is defined as annual operating cost minus annual gross revenue. Relative to TOU pricing, spot pricing increases the uncertainty associated with gross revenues but decreases the uncertainty associated with operating costs. At the present time, it is difficult to estimate the overall results on net revenue. The same arguments apply to the multiple year time variations of utility net revenues. Assuming equivalent revenue reconciliation procedures, the choice between spot and TOU pricing will have little effect on the uncertainty and time variability of utility net profits.

Some of the conclusions of the preceding discussions can be summarized as follows. First, although it is conceivable that spot pricing could cause system instabilities, there is no indication that this is the case. If it should occur, corrective mechanisms are available. Second, the difference between the time variability of the various quantities of concern under spot and TOU pricing does not seem to be a key issue. Third, spot pricing increases uncertainty in some variables and decreases it in others. One important question to be addressed is:

> Is the increased uncertainty in an individual customer's ability to predict his/her annual energy bill a major obstacle to implementation of spot pricing?

We believe the answer is no for two reasons. First, the acceptance by many customers of direct control load management and interruptible contracts indicates that some customers, at least, are willing to live with uncertainty that could be viewed as being larger than would exist under spot pricing. (For example, today customers are often not given forecasts of when control or interruptions might occur while forecasts of future spot prices enable rational planning.) Second, the futures market is provided to meet the needs of customers for whom uncertainty in their bill is important.

APPENDIX D

CHARACTERISTICS OF SPOT PRICE BASED RATES

APPENDIX D

CHARACTERISTICS OF SPOT PRICE BASED RATES

This Appendix discusses some of the major characteristics of spot price based rates. It expands on the ideas introduced in Chapter II on the characteristics of price only transactions and provides discussion on combined price/quantity transactions. Some brief examples of the relationship between these characteristics and existing rates are provided, but more complete discussions on these relationships are deferred to Appendix E. The ideas of this appendix are used as a starting point for the hardware discussions of Appendix F.

D.1 Customer Decisions and Control

Spot pricing is based on enhanced communication between the electric utility and its customers that facilitates customer action resulting in mutual benefits. Customer action consists of a decision followed by implementation. Define:

Decision: The decision of a strategy in response to available information on electricity cost, availability, etc.

Control: The implementation of a strategy consisting of consumption rescheduling, turning off or on usage devices, etc.

Two ways in which control may be exercised are:

Customer Control: Control is exercised by customer at the end use.

Utility Control: Control is exercised by the utility with decision values specified by the customer.

D.2 Price Only Transactions

Price transactions are spot price based rates that allow customers to use all the energy they desire, at the quoted price. The prices are set so that they reflect, to the extent allowed by advanced notice requirements, the actual system marginal costs and the cost to both the utility and its customers of maintaining a desired reserve margin. Table D.1 exhibits the key characteristics of price transactions covering three distinct time dimensions and one "quantification detail" dimension. The level of detail adopted for each characteristic defines a particular price transaction. For example, a cycle

TABLE D1

Key Characteristics of Price Only Transactions

Characteristics	Examples
Length of Price Cycle (Cycle Length)	1 year, 1 month, 1 day, 5 min.
Definition of Pricing Periods Within Cycles (Period Definition)	1 per year, 3 per day, 24 per day
Number of Different Price Levels (Number of Levels)	2, 3, Continuous
Advance Posting of Prices (Advance Notice)	1 month, 1 week, 10 hours, none
Number of Quantities	KwH only, KwH and KW

length of four months (i.e., today's frequency of price updates established by the Energy Cost Adjustment Clause) with three pricing periods per day and three different price levels corresponds to the time of use rate schedule in effect today with PG&E. A twenty four price trajectory posted at 4:00PM to take effect on 2:00AM for the next twenty four hours is the "twenty four hour update" spot price. Similarly, a spot price posted every hour is the one hour update spot price.

D.3 Combined Price/Quantity Transactions

Price/Quantity transactions cover contracts for electricity service at lower levels of reliability. Customers, instead of seeing high prices when low reserve margins are expected, contract a priori to reduce their usage when necessary to agreed upon levels. The utility exercises the options in the contract whenever it predicts capacity shortfalls (generation or transmission) or unacceptably small reserve margins. In terms of decisions and control, customers under a price/quantity transaction contract make decisions regarding consumption ceilings conditional upon certain events (capacity shortfall severities, etc.). Tables D.2 to D.5 exhibit the key characteristics of combined price/quantity transactions.

Many load management programs presently undertaken by PG&E and SCE (in fact all except time of use rates) fall under the price/quantity transaction type. Water heater control and airconditioning cycling are combined price/quantity transaction contracts with utility exercised control and a particular end use being the quantity controlled. The Demand Subscription Service (DSS), Group Load Curtailment (GLC) and COOP programs are price/quantity contracts with KW being the quantity controlled.

The principles for establishing the customer incentives for adopting price/quantity price contracts are to achieve (to the extent allowed by the particular characteristics of the contract) customer behavior as close as possible to what it would have been under spot pricing. Thus, customers receive incentives, (discounts, penalties, etc.) that tend to equalize on the average the marginal benefit the customer receives from his/her electricity usage to the marginal cost of providing it. This allows customers to minimize their costs while reducing utility costs as well.

Under certain conditions of customer incentives, a price/quantity transaction can become "equivalent" to a price only transaction. One example is when:

- o Customer's incentive for adopting a price/quantity contract is a reduced energy charge calculated as the expected spot price conditioned on thecritical event not

TABLE D2

Key Characteristics of Combined Price/Quantity Transactions

Characteristics	Examples
Length of Contract Cycle (Cycle Length)	1 year, 1 month, 1 day
Definition of Contract Periods within Cycles (Period Definition)	1, 3 per day
Number of Different Critical Events Determining when Utility Exercises Option (Number of Critical Events)	1, 3, Continuous
Options Utility can Exercise (Types of Options)	see Table D3
Customer Incentives for Adopting Contracts (Adoption Incentives)	see Table D4
Customer Incentives for Honoring Contract when Utility Exercises Options (Response Incentives)	see Table D5

TABLE D3

Categories of Options Utility Can Exercise
in Price/Quantity Contract

Option Category	Examples
Type and Level of Quantity Controlled	• Use of Particular Device • KW • KWH per period • KW and KWH
Advance Warning Time Before Quantity Control is Exercised (Warning Time)	12 hours, 1 hour, 5 min., none
Maximum Duration of Quantity Control (Control Duration)	8 hours, 1 hour, 5 min.
Frequency of Quantity Control (Control Frequency)	• Probability of Control during a cycle • Maximum number per cycle • Unspecified

TABLE D4

Customer Incentives for Adopting a Price/Quantity Contract

Type of Incentive	Examples
Fixed Incentive: Independent of Action	• $/month, $/sign-up • $/KW of contract/month • Decreased chance of blackout
Variable Incentive: Action Dependent	• $/action • $/KW/action
Price Discount	• Price less than Firm Price - Reduced Energy Charge - Reduced Demand Charge

TABLE D5

Customer Incentives for Honoring a Price/Quantity Contract

Type of Incentive	Examples
Monetary Penalty	• Fixed Sum Penalty • Variable Penalty Depending on Degree of Avoidance
Legal Penalty	• Loss of Right to Future Program Participation
Duration of Service Interruption	• Fixed Duration • Variable Duration Depending on Customer Action
Cost or Inconvenience for Overriding Utility Control	• Conscience • Diversion of Utility Control Signal (illegal action) • Installation of Alternate End Use Devices (illegal action)

occuring.

o Customer's incentive for honoring the price/quantity contract is a monetary penalty calculated to yield what the customer "should" have paid under a spot price calculated after the critical event occurred.

D.4 Comparison of Price Only with Price/Quantity

Price-only transactions simplify the marketplace interactions between the utility and its customers. Simplicity and ease of understanding are thought to be key components of success of any marketplace structure. Many of the desirable propoerties of combined price/quantity transactions can also be obtained with price only. Hence, price only transactions are viewed as the key component of spot price based transactions. However, price/quantity can have an important role.

Potential advantages of combined price/quantity transactions include:

- o Lower metering, communication (transactions) costs
- o Allowing additional degrees of freedom in rate choices
- o Simplification of customer's control problems by allowing utility to exercise control
- o Providing utility with more certainty regarding customer response.

These four potential advantages are discussed below.

Certain types of combined price/quantity transactions (such as direct appliance control and Demand Subscription Service) yield low metering and communication costs (see Appendix F). The main advantage in this area (over say, a two level price only transaction) is that the price only transaction requires some sort of metering of energy consumption during both levels.

The second potential advantage of additional degrees of freedom could be particularly valuable for less detailed spot price based rates with long cycles (month or longer) and only a few pricing period definitions (three per day or less). In such cases, the average value of the instantaneous spot price is not always adequate to elicit system wide cost-minimizing behavior since the correlation (see Appendix C) between customer demand and the instantaneous spot price may be non-zero. However, as discussed in Chapter III, the recommended price only transactions limit long cycle lengths to residential customers. Thus, this advantage of price/quantity transactions whould not be applicable to medium and large customers. Its usefulness for residential customers is questionable considering the relatively high costs involved in estimating the correct parameters of a complex rate.

The third potential advantage of combined price/quantity transactions (customer convenience) can also be realized by price only transactions with a utility provided customer control service. However, the transactions costs of metering and communication can be higher with the price only approach. This could be a real advantage for combined price/quantity especially when fast customer response (say, seconds to minutes) is wanted to deal with system operating problems such as the need to carry sufficient spinning reserve.

The fourth potential advantage of combined price/quantity involves increased certainty of customer response. The validity of this argument is subject to debate as issues can be presented on both sides. For example, direct control of a particular appliance at first seems to be more certain than indirect control via prices. However, predicting response to direct appliance control requires detailed modeling of an explicit appliance's usage pattern as a function of time of day, season, and weather (direct control only works when the appliance is on). Predicting response to a price only rate which applies to all of a customer's usage requires a more aggregate level of modeling and hence, can be more certain.

More research is needed before the relative roles of price only and combined price/quantity transactions are well understood. However, based on our present understanding, we feel that:

- o Price only, 24 hour or 1 hour update transactions are to be preferred for large industrial or commercial customers when 1 hour is the shortest time interval of concern.

- o Combined price/quantity transactions may have advantages for small residential customers.

- o Combined price/quantity transactions may have advantages when handling power system phenomena appreciably faster than one hour.

D.5 Futures Market

The major function of a futures market is to provide risk sharing among customers, the utility and other interested agents. A futures market provides for forward contracts consisting of a fixed quantity, fixed price agreement pertaining to a future point in time. The parties entering the contract realize profits or losses per KwH of the contracted amount equal to the difference between the contract price and the actual spot price at the agreed upon future point in time. Thus, the opportunity cost of electricity consumption remains equal to the spot price, eliciting efficient, cost minimizing behavior. However, risk sharing is also achieved, with risk shifted from risk averse to non-risk averse agents. The key characteristics of the futures market are exhibited in Table D.6. Thus, the opportunity cost of electricity consumption remains equal to the spot price, eliciting efficient, cost minimizing behavior. However, risk sharing is also achieved, with risk shifted from risk averse to non-risk averse agents. The key characteristics of the futures market are exhibited in Table D.6.

TABLE D6

Key Characteristics of Futures Market

Characteristics	Examples
Length of Contract Cycle (Cycle Length)	20 years, 1 year, 1 month
Definition of Contract Periods Within Cycle (Period Definition)	1 per month, 3 per day, 24 per day
Nature of spot price based rate available to customer for buying and selling difference between actual use and contracted amount of energy	see Tables D1 and D2

APPENDIX E

RELATIONSHIP OF EXISTING RATES AND LOAD MANAGEMENT PROGRAMS TO THE SPOT PRICE

Appendix E

RELATIONSHIP OF EXISTING RATES AND LOAD MANAGEMENT PROGRAMS TO THE SPOT PRICE

This Appendix discusses the existing rates and load management programs from the point of view of the spot price framework developed in Appendix D. Each existing rate/program is first defined and then conceptually related to the instantaneous spot price through a description of the corresponding spot market transaction characteristics. Then, a method for calculating appropriate rate levels using the instantaneous spot price is outlined. Thus the Appendix D framework's completeness and self-consistency is elaborated. The ability to relate each rate/program to a common reference (i.e., the instantaneous spot price) allows comparison and assures consistency.

While reviewing the spot price based calculation of rate levels outlined below, the reader should be cautioned not to assume that the proposed procedure will necessarily yield the same rate schedules used today.

E.1 Time of Use Rates

Time of use rates are in effect for a wide range of customer classes in PG&E's and SCE's service territories. For billing purposes, the hours of each day are grouped into three periods (peak, off-peak and partial or mid-peak) and a distinct energy and demand charge is applied in each period. Charges vary by season of the year and are adjusted for energy costs every four months.

Described as a spot price based rate, TOU rates are price only transactions with a cycle length of 4 months, a pricing period definition of 3 periods per day, a continuous number of price levels and two quantities priced (Kw & Kwh).

The spot price based procedure for calculating TOU rate levels at the beginning of each cycle would go as follows. The expected value of the instantaneous spot price during the peak, off peak and partial or mid-peak periods would be estimated over the four month cycle based on a load profile forecast and the related production cost and reliability simulation. Then the correlation between the projected customer demand profile and the instantaneous spot price would be estimated (recent historic data could be used). Since the cycle length is relatively long, and the price period definition quite aggregate, the correlation term (see Appendix C) may be non-zero. The correlation term may then be added to the energy charge or approximated by incorporation into the demand charge in line with present practice. The correlation term accounts for time aggregation and forecasting error related terms.

The experience with and analysis of TOU rates by PG&E and SCE will be useful in designing spot price based rates. As mentioned in Chapters II, III and IV and Appendix C, use of a consumer demand response model is required. In that vein, the elasticity estimates (both own and cross) developed by past and continuing studies conducted by PG&E and SCE could be utilized for a "first guess" at customer response. In addition, the familiarization of customers to the concept of time varying prices, which has been achieved by their exposure to TOU rates, will aid their ability to respond to spot price based rates.

E.2 Demand Charges

An implicit assumption justifying today's practice of a demand charge applied uniformly to all customers under the same schedule, is that each customer's demand exhibits the same correlation with the instantaneous spot price. Therefore, a shift in the relative importance of the demand charge in favor of the energy charge may be warranted or at least worthwhile investigating. This is already being adopted in PG&E's A-21 rate schedule. The "Green Tariff" employed by Electricite de France recognizes the effect of differences across customers and allows voluntary selection by each customer among alternative pairs of energy demand charges. The Electricite de France rate, however, is itself limited by the assumption that customers exhibiting the same load factor are similar as far as the correlation of their consumption to the instantaneous price is concerned.

Demand charges may be related to the framework of spot price based rates only to the extent that they are used as a approximation for factoring into the customer's rate the correlation of his demand profile to the instantaneous spot price. For spot price based rates with a short cycle length and a detailed pricing period definition, use of a demand charge is not necessary; a pure energy charge is sufficient to reflect system costs and induce cost minimizing behavior by the customer.

E.3 Interruptible Service

SCE's "General Service-Large-Interruptible" schedule No. TOU-8-1 will be discussed here as the characteristic interruptible service rate. Rate TOU-8-1 is an extension of SCE's TOU-8 schedule to include a firm and interuptible service defined by two agreed upon kw quantity limits. The utility can exercise the option of calling for interruptible load (exceeding quantity limits) to be disconnected from the company's lines. Depending on the notice given the customer before interruption, (30 min. or 10 min. minimum), the customer has to decrease his demand to the lower or higher of the two kw limits respectively. The customer faces a lower demand charge for consumption exceeding the kw limits.

Described as a spot price based rate, the above schedule is a combined price/quantity transaction with a contract cycle length equal to the billing period, three pricing periods within the contract cycle and two critical events determining when the utility exercises the interruption call. The events are defined as the situations in which within 10 or 30 minutes respectively, "the next-to-last available combustion turbine generator otherwise would be required to be operated". Following the utility's advanced notice the customer can decide and exercise control to abide by the contracted kw demand limits. Penalties for not honoring the contract are also included in the form of a variable charge per kw of demand exceeding the limit. The quantity controlled (see Table D3 in Appendix D) is kw demand and the maximum duration of the quantity control is equal to the length of the on-peak and mid-peak periods. The frequency of interruption calls depends on the probability of occurence of the critical events. This probability depends on system wide and aggregate demand characteristics.

The estimation of the charges for the firm and interruptible service can be based on the instantaneous spot price as follows: Firm service rates are identical to TOU rates whose estimation was outlined in E.1. Interruptible rates can be calculated as the average value of the instantaneous spot price over each TOU period in the cycle, conditional upon the relevant critical event (defined above) not occuring. Since at times of critical event occurrences, the instantaneous spot price will be high to reflect expensive marginal generation costs and a low reserve margin, exclusion of these high values from the average value calculation will yield a lower average value. The lower cost of interruptible service can be implemented in the rate schedule in the form of either a lower energy or demand charge.

The experience with interruptible service rate schedules and the data collected will provide very useful information for the implementation of spot price based rates. Of particular interest will be data on excess demand, i.e., demand exceeding the contractual kw limits when the utility has called for interruption. Such incidents provide information on the value of marginal electricity consumption to customers. This information will be useful in building the demand response model needed in estimating spot price based rates.

E.4 Demand Subscription Service (DSS), Group Load Curtailment (GLC) and COOP Programs

The DSS, GLC and COOP programs are similar to the interruptible service discussed above. They can be classified as combined price/quantity transactions with one critical event whose occurence triggers a utility call for interruption. The quantity controlled during critical events is kw and the kw limit of firm power is agreed upon a priori and stated in the contract. Under DSS the customer incentive to honor the contract is service interruption while under GLC/COOP it is a financial penalty charged for each non-compliance incident. DSS, GLC and COOP differ from the interruptible service in terms of the customer incentives to adopt the contract. These incentives are not related to the demand charge as is the case with the interruptible service, but take the form of a fixed credit or a rate discount.

Customer exercised control in the case of COOP, GLC and DSS increases the flexibility available to consumers and results in lower interruption costs. This is done, however, at the expense of some cost to consumers for making on-line decisions and coordinating their demand when control has to be exercised.

The DSS, COOP and GLC program experience will be useful in the design of spot price based rates because it can provide information on the demand response of commercial and residential consumers and the tradeoffs between different customer incentives.

E.5 Airconditioner Cycing (AC) and Hot Water Control (HWC)

The AC and HWC programs of SCE and PG&E can also be placed in the spot price framework. They are combined price/quantity transactions with a cycle length equal to the billing period, one critical event, the quantity controlled being the device itself and control exercised by the utility. Viewed as spot price based rates, AC and HWC programs should be priced as follows. The cost to the consumer of electricitry to operate the airconditioning or water heating device should be the expected value of the instantaneous spot price plus the correlation of instantaneous spot price and device consumption conditional upon partial operation (depending on cycling or control strategy) of the device during critical events. Thus, the incentive given to the customer should only depend on the electricity consumption of the device controlled and not on his/her overall consumption. If the incentive is to be given in the form of a bonus or other discount, the total value of the bonus or discount over each billing period should equal the difference between the unconditional and the conditional average value of the instantaneous spot price plus a correlation term. The conditional average value depends on the cycling or control strategy and thus the customer incentive (bonus or discount) depends on the strategy as well. The more severe the cycling strategy the higher the incentive.

At present, AC and HWC programs offer incentives ranging from flat rate credits to recruitment bonus, participation bonus and lifeline rates. It has been observed that customer adoption of the AC and HWC programs does not necessarily depend heavily on the level of incentive although it does depend on the method of payment (sign up bonus vs. monthly bonus). Further investigation linking incentives to cycling strategy and calibrating them to their spot price based level as outlined above may be desirable.

An example of conditions under which price/quantity becomes equivalent to price only arises when one considers an extension of the AC and HWC programs to allow customers to override utility control at an additional charge per override where the charge is based on the energy used during the override. In that case, the HWC and AC programs could be classified as price only transactions with a utility provided customer control service. The override provision adds additional flexibility and degrees of freedom for the consumer that may well result in higher benefits to the consumer and hence a higher adoption rate. The disadvantage of the override provision, however, is higher metering and transactions costs.

E.6 Priority Interruption System to Deal with Capacity Shortage

A priority procedure to deal with capacity shortages has been proposed in California. According to this proposal, electricity service by category of usage (not by customer) will be ranked in an agreement reached upon a priori by all parties involved. At times of capacity (and interchange) shortage, electricity service will be interrupted to those usages appearing at the top of the priority list and as far down the list as the severity of the shortage requires. This priority system can be interpreted as a spot price based rate as follows:

- The priority list is formed according to the value to consumers of each usage, with each position in the list corresponding to a "cut-off price", i.e., a price which would induce the consumer to voluntarily interrupt his usage.
- Different severity levels of capacity shortage are described in terms of critical events and their associated probabilities.
- Average values of the instantaneous spot price are calculated conditional upon each critical event occuring.
- The above conditional averages are used to adjust appropriately the rates charged for servicing usages in the priority list. Usages that are prime candidates for interruption according to the priority list will be associated with a more likely critical event. Their consumption would therefore be charged less than that of usages that are less likely to be interrupted according to the priority list.
- The charges of customers under spot based rates can be easily designed to reflect the priority system. The "cut-off prices" defined above will serve as limits to the instantaneous spot price (see Appendix C). These limits are exceeded only

when the capacity shortage can not be alleviated by the corresponding rationing prescribed in the priority list. Thus, a priority interruption system can coexist and be consistent with spot price based rates.

E.7 Block and Baseline Related Rates

Block and Baseline rates can be used in combined price/quantity transactions to approximate a lower charge for interruptible electricity usage and serve as discount incentives to participating customers. Block rates can be interpreted as a combined price/quantity spot price based rate. Block levels define the relevant quantity and the critical event triggering higher prices for consumption exceeding a set quantity is always in effect.

Both block and baseline based rates could be justified in the context of spot pricing as tools for income redistribution. In these cases, their use should be founded on unambiguous economic, equity or other social or political considerations and should be implemented in a fashion that allows customers to make consumption decisions on the margin based on the spot price.

The presence of baseline rates do not destroy the usefulness and implementability of spot price based rates.

E.8 Discussion

This appendix considered existing rates and load management programs, showed how they fit into the proposed spot price based rate framework, and outlined a consistent way of estimating customer charges under each rate/program. Thus, it provided a means for comparing the different rates and programs and using the data and analyses developed so far to evaluate and design spot price based rates. Parameter estimates describing demand response to time of use rates, adoption of interruptible service schedules and excess demand incidents can provide useful information for a starting point in the design of an experimental, large customer spot price based rate. Experience with load management programs has also yielded useful information on customer willingness to pay to avoid unserved energy.

The superiority of marginal cost based analysis of load management benefits over direct estimates of reliability impacts has been observed repeatedly in SCE and PG&E studies. The use of spot price determinants, marginal costs and reserve margin, to dispatch load management options has also proven superior to using system load, temperature or any other imperfect proxy of overall system condition. Rates based on such proxies like the San Diego system peak coincident demand charge and Long Island's temperature related rates have proven useful. Their effectiveness, however, could improve by a closer tracking of the instantaneous spot price.

The initial implementation of spot price based rates followed by complete adoption of the instantaneous spot price as the key determinant of various electric service rates, are a natural evolution of the ideas developed by the CPUC and California utilities over the last decade. The recognition of the importance of marginal cost studies by the CPUC was an important step in this evolution. PG&E's electric service marginal cost derivation consisting only of a "marginal operating cost" term and a "shortage cost" term is consistent with the instantaneous spot price definition.

APPENDIX F

Review of Available Hardware/Software For Implementing Spot Pricing

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Appendix F

REVIEW OF AVAILABLE HARDWARE/SOFTWARE FOR IMPLEMENTING SPOT PRICING

F.1. Introduction and Summary

In considering spot pricing today, many utilities and regulatory bodies are concerned about the costs and reliability of equipment required to implement spot pricing. They also are concerned about changes that may be required in utility operations to implement spot pricing. The purpose of this appendix is to preliminarily address these concerns about cost, reliability and operational changes.

Immediately below three major observations are made on these concerns of costs, reliability and operational changes. Next a summary table is presented that compares different forms of spot pricing. Then several observations about these forms of spot pricing are made. Finally, in Sections F.2 and F.3, the information is presented that led to these conclusions.

Costs. The question "Is spot pricing cost-effective?" should be changed to "Which form of spot pricing is cost-effective for this particular customer or customer group?" There are many forms of spot pricing. Each form has a different cost. These costs range from $130 to $900 a year. The $900 form of spot pricing --prices changing every 5 minutes--will certainly not be cost-effective for residential customers today or in 1990. However, the $130 form--direct appliance control--is cost effective for any customer that can provide the utility with 1 kw or more of equivalent capacity in load relief (assuming a capacity cost of $80 per kilowatt-year and $50 per year of meter reading and billing costs for customers on a regular flat kilowatt-hour rate). If in the cost-effectiveness analysis any benefit is assigned to equity (reducing the intraclass subsidization on rate structures that crudely reflect cost) or providing customers with options to control their utility bills, then some form of spot pricing (for example, conventional time of use pricing) could be justified for customers who provide less than 1 kw of load relief. In addition, in the future, equipment costs will decline relative to the price of electricity so that even more sophisticated rates can be made cost effectively available to smaller customers. Thus, today, and particularly in the near future, some form of spot pricing can be cost effectively offered to many, if not most customers.

Reliability. Equipment reliability is not a serious impediment today to implementing spot pricing. Some people have thought that the 10% annual failure rates being experienced by the utilities today for both time-of-use meters and communication receivers would render any metering system requiring real time communication too unreliable by historically accepted metering standards. This is not true, however. Consider the magnetic tape recorder meters used today for large customers. The annual failure rates for these recorders ranges from 6-12%. Yet if one looks at the performance of the whole metering/billing system, the percentage of good and usable billing data exceeds 99%. This high system performance occurs because of the quick error detection and error correction features built into the billing computer (and translator) part of the metering/billing system. That is, the computer is able to fill in some missing data to correct errors and flags the meter shop to quickly check out certain meters. Similarly, spot pricing transactions (except direct appliance control and demand subscription service that do not have special meters) can use the billing computer for error detection and error correction to maintain a high system performance. To be sure, high meter and communication receiver failure rates increase the operating costs--which must be included in the cost effectiveness analyses. But such high failure rates do not prevent a high system performance. Many people have incorrectly extrapolated the problems of error correction and error detection of direct appliance control and demand subscription service to the other forms of spot pricing.

Operations Changes. Once prices have been determined (these operations changes are discussed in Appendices D and E), most spot pricing transactions will require few changes in utility operating practices beyond what the utility currently does for time-of-use and curtailable rates. More meter readers will probably be required to read the more sophisticated meters. Meter shop personnel will have to be capable of servicing the communication receivers as well as the meters and more meter shop personnel will be required. The amount of error correction and error detection done at the billing computer will increase and it will take time to develop and de-bug the necessary software. However, few other major changes in organization and operating procedures are required. In contrast, direct appliance control may require a separate field force to install equipment on appliances and possibly rigorously test for equipment errors. It should be noted, however, that having such a field force is not necessarily a bad change if the utility is interested in getting into the energy services business.

F.1.1. Spot Pricing Cost Comparison

Table F.1 shows the annualized system costs for 18 different types of spot pricing transactions. Eight of the transactions (Nos. 9 through 16) have the same communication-metering system requirements and cost as eight other transactions (Nos. 1 through 8). Hence only ten different cost cases must be considered. The cost estimates are approximate.

TABLE F.1

SPOT PRICING SYSTEM COSTS

Transaction Number[4] and Example	Annualized Costs, 1982[1,2] 1982$	Annualized Costs, 1990[1,2] 1982$
1,9 Conventional Flat Rate	50	50
2,10 Conventional TOU Rate	150	125
3,11 Curtaillable Rate 12 Hour Notice Fixed Length Curtailment	210	140
4,12 Conventional TOU Rate Except Prices Can Change Each Day	650	225
5,13 Curtaillable Rate 12 Hour Notice Variable Length Curtailment	210	140
6,14 TOU Rate Prices Vary By Hour 12 Hour Notice	650	250
7,15 Curtaillable Rate 5 Minute Notice Variable Length Curtailment	250	140
8,16 TOU Rate Prices Vary Every 5 Minutes 5 Minute Notice	900	350
17 Direct Appliance Control	130[3]	90[3]
18 Demand Subscription Service	180[3]	135[3]

FOOTNOTES

SPOT PRICING SYSTEM COSTS

Table F.1

1. These costs are the total costs, capital and expense, on an annualized basis of the communication-metering system required to implement these transactions. This system contains five main functions: a) communicating the forecasted price from the utility to the customer, b) communicating the actual price from the utility to the customer, c) communicating a price period change from the utility to the meter, d) metering the electricity use for each price period, and e) communicating the electricity use from the meter to the billing computer. See Table F.8 in Section F.3 of this Appendix for the development of these cost estimates. These cost estimates are approximate--they are intended to indicate the range of cost variation among transactions. More detailed estimates should be prepared for major decisions.

2. These costs assume single phase meters. Add $40-70 for systems using three phase meters.

3. These costs include the $50 cost for the single register meter "system" since that system is a part of this system.

4. The transaction numbers and formal descriptions are given in Tables F.2 and F.3 in this Appendix.

They are intended only to indicate the range of cost variation among transactions. More detailed estimates should be prepared for major decisions.

Transaction numbers 1 through 8 are Price-Only transactions. Price-Only transactions allow the customer to consume as much electricity as he wants any time that he wants as long as he is willing to pay the price. Combined Price-Quantity transactions, numbers 9 through 18, limit the customer's usage during some critical time period in exchange for some price discount or incentive. An example is given for each of the 10 cost cases considered so that the reader can better get a feel of the equipment and personnel activities involved.

To estimate the costs of this communication metering system, the costs of the following five components of that system were estimated:

a. communicating a forecasted price from the utility to the customer,
b. communicating an actual price from the utility to the customer,
c. communicating a price period change from the utility to the meter,
d. metering electricity use for each price period, and
e. communicating the electricity use from the meter to the billing computer.

As an example, consider transaction No. 11--a curtailable rate with a 12 hour notice and a fixed length curtailment. Under this rate the customer knows that if she has a curtailable period on a given day that it will occur from 12 noon to 6 p.m.[1] (Footnotes are given at the end of the Appendix.) For component a, the utility forecasts in the Sunday newspaper which days that week a curtailment is likely. The actual price or curtailable period in effect is communicated to her from the utility by the morning newspaper each day--hence the cost of the utility posting this notice in the newspaper is the cost of component b. The utility sends a radio signal to the receiver inside the meter to communicate the price period change at 12 o'clock that day--hence the radio receiver is the cost of component c. A second register in the meter is used to accumulate the customer's usage during the curtailable period to make sure she has stayed below her subscribed limit--hence the cost of a 2-register meter is the cost of component d. And finally at the end of the month, the meter reader comes around and records the customer's usage during the critical period(s) as well as her normal usage--hence the meter reader cost is the cost of component e.

The costs given here are annualized costs. That is, these costs include the levelized capital charges plus operation and maintenance expenses. These costs for 1982 are based largely on the experiences of Pacific Gas and Electric and Southern

California Edison and the authors' discussions with manufacturers. The 1990 cost estimates are the authors' extrapolations from today's costs and cost trends. See Table F.8 in Section F.3 for the development of these cost estimates.

Costs are given for 1982 and 1990 using 1982 dollars for both years to show how these transaction system costs will change relative to the general inflation rate and presumably the price of electricity. For 1982 costs, off-the-shelf technology is assumed. For 1990 costs, appropriate technological development for a volume of at least 200,000 customers is assumed.

Table F.1, or a more refined revision of it, can be used to help select what transaction is appropriate for a particular customer or customer group. The cost of the system supporting the rate or transaction which the customer has today is compared to the costs of the system of the rate or transaction contemplated for that customer. If the difference in these two systems' costs is less than the benefits of moving to the other rate, then that customer should move to the rate or transaction being contemplated. For example, if the customer is on a conventional flat rate for 1982 and is considering choosing the conventional time-of-use rate in 1982, then the benefits of moving to the time of use rate would have to exceed $100 ($150 minus $50--see costs in Table F.1) each year. The questions of what should be included as benefits (kw reduction only or also reduction in intraclass subsidization from a rate structure that better reflects cost) and measurement of those benefits are left for another discussion.

F.1.2. Why Cost Reduction in 1990?

With this background on Table F.1, several significant observations can be made. First, all transactions' systems, with the exception of the conventional flat rate, decline in costs (in real dollars) from 1982 to 1990. Second, some transaction systems decline in cost significantly more than others. Third, the range of transaction system costs in 1990 is one-third of the range in 1982--indicating the possibility/desirability of the UMACS (Universal Metering and Control System) described in the text.

There are four driving forces discussed below that cause these cost reductions. The conventional flat rate system is affected by none of these forces and the systems of some transactions are influenced by these forces more than others.

Order Volumes. Utilities frequently order load management equipment (e.g., load control receivers) in small volumes today. In 1990 utilities are individually or collectively assumed to order 100,000-200,000 units. The impact of volume can be seen today (August 1982) in that VHF radio control receivers typically range in price from $55 to $80 for orders of 100,000 units or one unit, respectively.

Failure Rates. All communication receivers and time of use meters are experiencing failure rates today of about 10%. By 1990 both utilities and vendors expect these failure rates to drop to 2%. The decrease in failure rates will significantly decrease the O&M costs for these systems. This is particularly true for the systems of transactions 3, 5, and 7 that have both a communication receiver and a time of use meter.

Electronic Component Costs. The costs of the electronic components in communication receivers and time of use meters is expected to remain at today's price level in 1990 dollars. When adjusted for the increase in inflation, that represents a significant decrease in real costs. The basis of this assumption is that technological development will offset the increases in labor and material costs for electronic components. The systems for transactions 3-8, which have the most electronic components, will benefit the most from these technology improvements.

Product Design and Packaging. The equipment costs for transactions 3-8 reflect the use of off-the-shelf equipment that has not been designed specifically to accomplish the communication-metering requirements for those transactions. When the products are designed and packaged to meet these particular functions, then the costs will drop dramatically. For example, transaction 4 is a conventional time of use rate in which the prices can change each day. Hence during a billing month, only 60-90 values need to be stored. However, today to record and store those 60-90 values a load survey recorder must be used: hence the $650 annual cost. Nonvolatile memory or battery backup adds to the cost. In the future when the memory is sized closer to the actual requirements and the meter is packaged more like today's solid state time of use meters, then the costs will drop dramatically. Consider another example of cost reduction through better packaging. The costs in Table F.1, for transactions 3, 5, 7, and 8 assume the communication receiver and the meter have a separate housing in 1982. By 1990, the receiver and meter can be packaged in this same housing just as in the demand subscription service device the receiver and relay are packaged in the same housing and integrated in design. Note that the first demand subscription service devices, before the integration in design, cost $600. Now with this integration in design manufacturers indicate that they can supply the unit in orders exceeding 100,000 for less than $300, including the customer alert device.

F.1.3. Can Cost Reductions be Accelerated?

Since the cost reductions shown for 1990 make some spot pricing transactions considerably more attractive, the question naturally arises as to what extent these cost reductions can be accelerated. To answer that question, consider to what extent each of the four driving forces can be accelerated.

Volume Orders. Utilities can accelerate volume orders in two ways. First, they can plan purchase orders over a longer time span. Second, where equipment requirements coincide, they can plan and order collectively with other utilities.

Failure Rates. To some extent reducing the failure rates reflects a "learning curve" experience. That is, as volume purchases are accelerated, the vendors and utilities learn faster how to design, install, operate and maintain this equipment to make it more reliable, and so move up the "learning curve." However, if volume increases too quickly, then chaos replaces learning on the learning curve. A more critical factor on failure rates, however, is for utilities to evaluate what the trade-off is between O&M costs and the capital costs of higher reliability equipment, and write the equipment specifications accordingly. At the current trend of volume and specifications, the vendors and utilities expect these failure rates to be down to 5% in a couple of years.

Electric Component Costs. Aside from volume orders utilities can do little to accelerate electronic component cost reduction. Most of these improvements are being forced by the commercial markets (toys, personal radios). Utilities are at the mercy of the trends in developments in those markets.

Product Design and Packaging. Product Packaging is a force that the utilities have control over through purchase plans and order volumes. The demand subscription service device is a good case in point. By giving the demand subscription service concept serious commitment, Southern California Edison was able to bring a prototype concept into the realm of a cost effective load management alternative within a couple of years. If a similar commitment were given to transactions 3, 5, and 7, which are very similar to the demand subscription service transaction, system costs for those transactions could approach that of the demand subscription service transaction in a couple of years.

In the rest of this appendix, the analysis and assumptions that led to the observations in Section F.1 are given.

Section F.2 analyzes the functional requirements of the communication-metering systems necessary to implement the different spot pricing transactions of interest. Section F.3 reviews the cost and reliability of equipment available now and in 1990 to meet those functional requirements.

F.2 Hardware Functional Requirements for Spot Pricing

The purpose of this appendix is to review the functional requirements and cost and reliability of communication and metering hardware necessary to implement spot pricing. In Section F.2, the functional requirements are defined. In Section F.3, the hardware options available to meet those functional requirements are identified. Also in Section F.3, the cost and reliability of this hardware today and in 1990 is reviewed.

Due to the scope of this study, a somewhat simplistic approach to identifying functional requirements must be taken. The first simplification is to focus only on the few functional requirements that most distinguish the hardware costs and reliability of various spot pricing transactions--see Section F.2.1. The second simplification is to evaluate the functional requirements of only 18 spot pricing transactions rather than try to evaluate the functional requirements of all possible spot pricing transactions.

The structure of this report is:

- Describe the functional requirements being considered in Section F.2.1
- Identify the transactions being examined in Section F.2.2
- Analyze the particular functional requirements on identified transactions in Section F.2.3, and
- Conclude in Section F.2.4

F.2.1. Functional Requirements

In examining the communication-metering system for implementing spot pricing, five main functional components can be defined:[2]

a. communicating the <u>forecasted</u> prices from the utility to the customer,
b. communicating the <u>actual</u> prices from the utility to the customer,
c. communicating the price period changes from the utility to the meter,
d. metering the customer's electricity use by price periods, and
e. communicating the electricity use from the meter to the billing computer.

Today these five functions are mainly accomplished in the following ways:

a. the <u>forecasted</u> price is communicated from the utility to the customer via the utility newsletter, the existing news media (newspaper, radio, TV) and customer service representatives.

b. The price is communicated from the utility to the customer via the bill or through a rate schedule mailed to the customer,
c. the price period changes are communicated to the meter by setting the time of use meter's clock-calendar in the meter shop or else no price period change is communicated (as in the case of the single register meter or magnetic tape recorder),
d. the electricity use is metered by measuring the electricity used with a watt-hour meter--an induction-powered rotating disc--and then storing the data on site in an unprocessed form (for example, magnetic tape recorder) or in a processed form (one kilowatt hour value is accumulated for each different price period), and
e. the customer's electricity use data is communicated back to the billing computer via a meter reader on a computer readable card or on a magnetic tape, and then translated and edited so it is ready to print the bill.

Spot pricing will, in at least some forms, require different approaches to accomplish these functions.

Three factors mainly determine which hardware will be required to satisfy these five functions for any given spot pricing transaction. These three factors are:

1. the amount of time available to communicate price to the customer or price period change to the meter, and
2. the amount of data that must be communicated to/from or stored at the meter.
3. the reliability with which the data must be communicated or stored--assumed to exceed 99%.

These requirements are, of course, further constrained by cost-effectiveness and other limitations. The amount of time available for communication significantly influences the choice of communication medium, and hence the cost and reliability of the total communication metering system. If, for example, the utility has over a month to communicate a price change to the customer, it can use its existing bill. If, on the other hand, it has 12 hours to communicate price, it could use the newspaper. However, if the utility has only 5 minutes to communicate a price change, it must use some electronic communication medium.

Similarly, the amount of time available to communicate a price period change to the meter influences the communication medium choice. If the price period changes are known over a year in advance, such price period changes can be programmed in by meter shop personnel. If, on the other hand, price period changes are known over a month in advance, they can be programmed in by the meter reader (assuming the meter reader reads the meter once a month). If the price period changes are known less than a month ahead, then either (1) an electronic communication medium must be used to remotely switch meter bins or "registers", or (2) the meter memory storage must be greatly increased (for example, use a magnetic tape recorder).

The amount of time available for reading the meter under spot pricing is no different than today. That is, in spot pricing, time is critical only for communicating from the utility to the customer/meter--not for communicating back from the customer/meter to the utility. Hence, meter reading time is not a functional requirement needing special consideration for spot pricing and is not discussed further here. However, reading a meter more frequently offers several advantages (e.g., quicker detection of a failed meter). A utility should consider it, however, in selecting communication equipment.

The amount of data that must be communicated to/from or stored at the meter also significantly influences the choice and cost of hardware. Consider first communicating price to the customer. If before the price change (as for curtailable rates) there are only two potential price (control) levels, then an electronic signal only must indicate which one of the two price levels is in effect at that time: the message can be relatively short--several bits. However, if the price options are not restricted, the electronic signal must provide the actual numerical value of the price: the message is relatively long--24-32 bits. Depending on the medium, increased message length means either lower reliability, greater air time requirements, or a higher cost terminal for error detection and correction to maintain the same reliability.

The amount of data stored at the meter also influences hardware choice and cost. Since a meter must not lose its information during a power outage, its memory must be non-volatile or have a battery back-up--neither of which is inexpensive.

Data volume also influences the medium for communicating the usage data back to the billing computer. If more than a few values must be communicated, the utility will not want to have the meter reader writing down the values on a card. Some other medium such as a hand held meter-reader, a magnetic tape or silicon chip would be preferred to transport this information.

Reliability is the third factor influencing the choice of communication and storage media. Some media are more reliable than others. For example, today telephone is a more reliable two-way communication medium than power line carrier. For some customers a higher reliability is desirable than others. For example, today utilities often have 2 or 3 meters (standard meter, magnetic tape and paper tape) on the largest customers to ensure an accurate recording and transfer of usage data. For smaller customers, where the cost or consequence of incorrectly interpolating missing data is considerably lower, only one meter is used. Thus, in choosing communication and storage media for a particular customer, the reliability desired for that customer and the reliability experience of the various media must be considered.

In section F.2.3, when analyzing the functional requirements of the identified transactions, the amount of time available for communication and the amount of information to be communicated to/from or stored in the meter will be focused on in the analysis. Reliability is customer specific or equipment specific more than transaction specific. Thus, the reliability analysis is deferred to Section F.3.

F.2.2. Spot Pricing Transactions Selected

It is impossible to consider the functional requirements and hardware costs of all possible spot pricing transactions. Certain representative transactions must be selected and analyzed in detail. The reader will then be left to extrapolate to other transactions of interest.

The text of this report discusses two types of transactions: Price-Only and Combined Price/Quantity transactions. For Price Only transactions, the customer is provided the price and is allowed unrestricted use of electricity at that price. For Combined Price/Quantity transactions, the customer is given a price discount for accepting a limitation on her electricity usage during certain critical events. A conventional time of use rate is an example of a Price Only transaction. A conventional curtailable rate is an example of a Combined Price/Quantity transaction. In this hardware analysis, both Price Only and Combined Price/Quantity transactions are evaluated.

Eight cases of Price Only transactions are considered in this analysis. These cases are defined in Table F.2, according to their characteristics. These cases have been more fully described elsewhere in this report. To refresh the reader an example of each case is given here.

1. A conventional flat or single price kilowatt hour rate.
2. A conventional time of use rate.
3. A conventional two price time of use rate in which a third super peak price is charged during the peak

TABLE F.2

PRICE ONLY TRANSACTIONS: CASE SELECTION FOR IMPLEMENTATION AND HARDWARE DISCUSSION

B. Cycle Length, Period Definition, Number of Levels Combination

Cycle Length, Period Def. / No. of Levels	1 year/ month 1 year/ month	1 year/ month 2-3 per day	Day 2-3 per day	Day 24 per day	5 min. 1 per 5 min.
1	X^1				
2-3		X^2	X^3	X^5	X^7
Continuous			X^4	X^6	X^8

Eight cases have been selected.

Note: Superscript numbers are the case numbers.

period on a few critical days of the year.

4. A conventional two price time of use rate except that the utility changes the prices daily; this differs from transaction 3 in that under transaction 4 the utility is not restricted to choosing from three different price levels when it assigns prices for each new day.
5. A conventional time of use rate except that the utility can vary the length of the peak period each day according to the expected system conditions that day.
6. A time of use rate in which the prices vary by hour and the customer is told a day ahead what each hour's price will be.
7. A conventional two-price time of use rate except that the peak price can be charged at any time if a critical system condition occurs.
8. A time of use rate in which the price changes every 5 minutes.

Ten combined Price/Quantity cases are selected. Eight of those cases are defined in Table F.3. Close inspection of Table F.3 reveals that Table F.3 is a mirror image of Table F.2. This "mirror image" has been selected to simplify the analysis in section F.2.3. The only difference between Tables F.2 and F.3 is that "Number of Levels" is now the number of Combined Price/Quantity levels rather than just Price-Only levels. For example, a conventional curtailable rider appended to a flat rate would have two Combined Price/Quantity levels--one Price-Only level and one Quantity or firm service level.

For these 8 transactions it is assumed that a meter is present to monitor the customer's compliance with the Combined Price/Quantity contract. Most commercial-industrial Combined Price/Quantity contracts (usually curtailable or interruptable rates) have meters present. However, two prominent residential Combined Price/Quantity transactions (direct appliance control and demand subscription service) do not have a special meter to monitor compliance. Because of the special interest in the residential direct load control and residential demand subscription service transactions, they are analyzed here as transactions 17 and 18, respectively.

To help the reader get a better feel for the ten Combined Price/Quantity transactions considered, examples are given for each of these transactions below.

9. The Los Angeles Department of Water and Power's mandate that customers reduce total usage by 20% from the previous year during the 1973 embargo.
10. A curtailable rate in which the customer must live below the firm service level from noon to six every week day of the year.

TABLE F.3

COMBINED PRICE/QUANTITY TRANSACTIONS: CASE SELECTION FOR IMPLEMENTATION AND HARDWARE DISCUSSION

B. Cycle Length, Period Definition, Number of Levels Combination

Cycle Length, Period Def. / No. of Levels	1 year/ month 1 year/ month	1 year/ month 2-3 per day	Day 2-3 per day	Day 24 per day	5 min. 1 per 5 min.
1	X[9]				
2-3		X[10]	X[11]	X[13]	X[15]
Continuous			X[12]	X[14]	X[16]

Eight cases have been selected.

Note: Superscript numbers are the case numbers.

11. A curtailable rate in which the utility specifies one day in advance whether the customer must live below his firm service level from noon to six on the following day.
12. Same as transaction 11 except the utility can specify almost any percentage reduction from a predetermined level that the customer must provide from noon to six on the following day.
13. Curtailable rate in which utility specifies on one day not only whether the firm service level will be in effect the next day but also what the length of the curtailable period will be.
14. Same as transaction 13 except the utility can specify almost any percentage reduction from a predetermined level that the customer must provide during the curtailment period.
15. Curtailable rate in which the utility provides a 5 minute notice for a customer to go to a predetermined firm service level and the curtailable period can be of variable length.
16. Same as transaction 15 except the utility can specify almost any percentage reduction from a pre-determined level that the customer must provide during the curtailable period.
17. Direct Appliance Control--air conditioner cycling.
18. The Demand Subscription Service as used by SCE.

F.2.3. Functional Requirements Analysis of the Selected Transactions

With the important functional requirements specified and the transactions of interest selected, the specific functional requirements of these selected transactions can now be analyzed. Much can be learned by taking a second look at Tables F.2 and F.3. In these tables, the transactions are characterized in a way that makes their functional requirements easier to discern.

By looking at the characteristics of the transactions in Table F.2 and F.3, several things can be learned about the functional requirements of each transaction. For example, the cycle length indicates when the price is updated. This span of time is the maximum amount of time the utility has to communicate to the customer a price change. For example, if the prices are updated every 5 minutes, then the maximum amount of time the utility has to communicate the price change is 5 minutes from one price update to the next.

A second important characteristic is the number of levels. It indicates the amount of information that must be communicated to the customer. For example, the second row in the Tables indicates 2 or 3 price levels. If the customer can be told ahead of time what the price values are for each of the two or three levels, then the utility must only communicate which level is in effect on any given day. However, if the utility has a continuous choice of price levels for that price cycle, then the utility must communicate the actual value of a price for any given period.

A third characteristic, period definition, indicates the maximum amount of storage required at the meter. For example, if there are 24 periods a day for transactions 5 and 6, and 30 days between meter readings, then the maximum number of storage requirements is 24 times 30, or 720 values (ignoring any desired redundancy between meter readings for reliability).

Extrapolating from the observations made about Tables F.2 and F.3, a summary analysis table appearing in Table F.4 has been prepared. In Table F.4 the communication and metering functional requirements--with particular emphasis on amount of communication time and amount of data to be communicated to/from or stored at the meter--comprise the column headings across the top of the table. The transactions selected comprise the row headings along the left hand column of the Table. Four significant observation from this table should be noted.

The first is the duality relationship in communication and metering functional requirements for Price-Only transactions 1 through 8 and Combined Price/Quantity transactions 9 through 16. In other words, for each Price-Only transaction there is a "dual" or corresponding Combined Price/Quantity transaction that has exactly the same communication and metering functional requiremernts. For example, one version of transaction 7 is a two-price time of use rate in which a "normal" price is normally in effect but a "floating peak" price can be put into effect during critical conditions on a five minute notice. The communication functional requirement of this transaction is to be able to communicate which price level (normal or floating peak) is in effect to the customer and to the meter in less than 5 minutes.[4] The metering requirements of this transaction are to be able to store 2 values--the cumulative normal kilowatt hour usage and the cumulative floating peak kilowatt hour usage. The corresponding "dual" of transaction 7 is the curtailable rate under transaction 15: One firm service level that can be invoked during critical conditions upon a 5 minute notice in conjunction with a normal flat rate. The communication functional requirements of this transaction are to be able to communicate which of the two levels (firm service or no control) are in effect to the customer and the meter in less than 5 minutes.[4] The metering requirements are to be able to store two values--the cumulative kilowatt hours used during the no control period and the cumulative kilowatt hours used during the curtailable or critical condition period. The utility will check on its billing computer to make sure the critical period use is below the customer subscribed level

TABLE F.4

COMMUNICATION AND METERING FUNCTIONAL REQUIREMENTS

OF THE TRANSACTIONS SELECTED

Transaction Number and Example	To: What: When:	COMMUNICATION Customer Price Level (L) >12 hrs.	Customer or Value (V) < 5 min.	Meter Price ≥ 1 mo	Meter Period Change Instantaneous[1]	METERING No. of Values Stored Between Meter Readings[2]
1,9 Conventional Flat Rate	(L)	X		X		1
2,10 Conventional TOU Rate	(L)	X		X		2-3
		X			X	2-3
3,11 Curtaillable Rate, 12 hr. Notice Fixed Length Curtailment	(L)	X		X		2-3 per day
		X			X	2-3
4,12 Conventional TOU Rate Except Prices Can Change Each Day	(V)	X		X		2-3 per day
		X			X	2-3 per day
5,13 Curtaillable Rate, 12 hr. Notice Variable Length Curtailment	(L)	X		X		24 per day
		X			X	2-3
6,14 TOU Rate, 12 hr. Notice Prices Vary By Hour	(V)	X		X		24 per day
		X			X	24 per day
7,15 Curtaillable Rate, 5 min. Notice Variable Length Curtailment	(L)		X	X		288 per day
			X		X	2-3
8,16 TOU Rate, 5 min. Notice Prices Vary Every 5 min.	(V)		X	X		288 per day
			X		X	288 per day
17 Direct Appliance Control	(L)		-	Appliance		1
18 Demand Subscription Service	(L)		X	DSS Device		1

[1]Approximately Instantaneous

[2]If the rate contains demand charge(s), then the number of values stored at the meter, as listed here, must be increased by the number of demand charge price/period options.

during that month.

Because transactions 7 and 15 have the same communication and metering requirements, our analysis and discussion simplifies. Any statement made about the communication and metering functional requirements of a Price-Only transaction in Section F.2 and its hardware costs and reliability in Section F.3 will also apply to its Combined Price/Quantity "dual". Thus, in the remainder of this report Combined Price/Quantity transactions 9-16 are not explicitly analyzed. The analysis of the corresponding Price-Only transaction should be applied to these Combined Price/Quantity transactions.

Combined Price/Quantity transactions 17 and 18 (direct appliance control and demand subscription service) do not have corresponding Price-Only duals because these transactions do not use a meter to monitor the customer's compliance with the transaction terms. Thus, direct appliance control and demand subscription service must be discussed separately.

The second observation is that few of the transactions from Table F.4 <u>require</u> a special electronic communication link be established with the customer. Moreover, none of the transaction requirements require a two-way electronic communication link.[5] Only the transactions to the bottom of the table--7, 8, 15, 16, 17 and 18--require one-way communication to the customer in less than 12 hours. Thus, for the other transactions, existing mass media--newspapers, TV news, radio news, etc.--can be used to broadcast the price. Not requiring a special link offers the opportunity for reduced communication costs.

Although somewhat obvious, this third observation is still important. As the number of time periods and price levels increase, the meter storage requirements increase. For example, transaction 6 with hourly varying prices and an unrestricted price choices requires 24 values per day or 720 values per billing month of meter storage. This contrasts sharply with the 2-3 values per billing month required by conventional time of use rates under transaction 2.

The fourth observation is that, although not required, a special one-way electronic communication link to the meter can reduce meter storage requirements. For example, transaction 5 has only 2 or 3 price levels from which the utility chooses a price for each hour of the day. However, since these prices are not set until a day ahead, it is impossible to preprogram into the meter's clock calendar when these 2 or 3 prices will occur. Without a special communication link, the meter would have to store the prices for each hour of the billing month--a total of 720 values. But with a special communication link to tell the meter when each of the 2 or 3 prices is in effect, the meter would only need 2 or 3 bins or "registers" to store usage values--one for each price level. The Europeans have used a ripple communication system to switch meter registers on time of use rates like this for several decades.

The special one-way communication link to the meter does not always help, however. For example, in transaction 6 the utility assigns prices to each hour of the day as in transaction 5. But, the utility is not restricted to choose from just 2 or 3 price levels. Thus, the full 720 values of the billing month must be stored in the meter for transaction 6 since each hour could have a different price. In this case, the utility would need a two-way communication link to reduce meter storage. If the meter of transaction 6 were read every day rather than every 30 days, meter storage requirements would be reduced from 720 values to 24 values. Hence, for some transactions (3, 5, and 7) a special one-way communication link to the meter can reduce meter storage, but for other transactions (4, 6, and 8) a two-way link (or very frequent manual meter reading) is required to reduce meter storage.

F.2.4. Conclusion

Many times the spot pricing of electricity is declared impractical because of the cost and the complexity of the communication and metering hardware. Many of those declarers envision a two-way electronic communication system between the utility and every customer. When spot pricing is first approached by defining functional requirements, one finds that, although sometimes beneficial, a two-way electronic communication system is never functionally required. One also finds that much of the cost and complexity aura of spot pricing disappears.

In the next section, hardware options available to meet these functional requirements are discussed. The cost and reliability of these hardware options are also discussed.

F.3 Costs and Reliability of Hardware for Implementing Spot Pricing

In the previous section, the functional requirements for the spot pricing transactions of interest were identified. In this section the hardware options available to meet these functional requirements are listed. The cost and reliability of these hardware options are also given.

This information on available hardware options and their cost and reliability has been summarized in Tables F.5, F.6, and F.7. Each table contains the information for a different component of the five major components to the system for implementing spot pricing:

a. communicating the forecasted prices to the customer,
b. communicating the actual prices to the customer,
c. communicating the price period changes to the meter,
d. metering the customer's electricity use, and
e. communicating the electricity use from the meter to the utility's billing computer.

Table F.5 summarizes the experience for the first three components--communicating from the utility to the customer and meter. Table F.6 summarizes the metering experience. Table F.7 summarizes the experience for communicating the customer's usage from the meter back to the utility's billing computer.

The cost and reliability numbers in these tables for 1982 are largely based on the experience of Pacific Gas and Electric and Southern California Edison and the authors' discussion with manufacturers. Cost and reliability estimates for 1990 are extrapolated by the authors from the 1982 experience and other industry trends. Detailed footnotes are provided in the tables so the reader can understand the basis for the estimates. Cost and reliability experiences reported are intended only to indicate the approximate variation in the options. More detailed estimates than those in these tables should be prepared for any major decisions.

The next three sub-sections of this Section are a review of the highlights of each of these three tables. Section F.3.4 combines the information from those three sections to present a summary cost of the system to implement each spot pricing transaction of interest in Table F.8.

F.3.1. Communication to the Customer and Meter from Utility

Table F.5 summarizes the cost and reliability experience of equipment used to communicate with the customer and meter. The first column in Table F.5 lists the communication functional requirement, that is the amount of time available

TABLE F.5

COMMUNIATION EQUIPMENT OPTIONS:

UTILITY TO CUSTOMER & METER

Functional Requirements Time Available to Communicate Price Change AND To Whom		Installed Cost[1,2] 1982	Installed Cost[1,2] 1990	O&M Cost[1] 1982	O&M Cost[1] 1990	System Reliability[3] Annual Failure Rates 1982	System Reliability[3] Annual Failure Rates 1990	System Reliability[3] Performance % 1982	System Reliability[3] Performance % 1990
1. Over 1 year: to meter	Meter Shop Staff	<1	<1	5[4]	10	-	-	99+	99+
2. Over 1 month: to meter	a. Meter Reader -Portable Programmer	.60[5]	.60	3[6]	5	-	-	99+	99+
to customer	b. Meter Reader -Leaflet	0	0	.60[7]	1	-	-		
3. Over 2 days: to customer	Mail	0	0	3[8]	5	-	-	99+	99+
4. Over 12 hours: to customer	a. Newspaper	0	0	0-10[9]	0-18	-	-		
	Phone-Customer Call	.40[10]	.70	.60[11]	1	-	-		
	Combined[12]	.40	.70	1-11	1-19	-	-	99+	99+[12]
	b. TV News	0	0	?[13]	?	-	-		
	c. Radio News	0	0	?[13]	?	-	-		
	d. CATV News	0	0	?[13]	?	-	-		
	e. Phone--Utility Call	8[14]	1[14]	20[15]	35[15]	-	-	99+	99+
5. Under 5 minutes: to meter or customer	a. Phone	400[16]	150[16]	180[17]	315[17]	1-10[18]	1-2[18]	99+[19]	99+
	b. Radio	140[20]	30[20]	16[21]	7[21]	10[22]	2[22]	99+[23]	99+
	c. Power Line Carrier								
	-Ripple[24]	160+	60+	10	5	2	2	99+	99+
	-Other[24]	160+	60+	20	8	10	2	98+[23]	99+
	d. CATV[25]	500	500	<180	?	?	1-2	?	99+

FOOTNOTES

COMMUNICATION EQUIPMENT OPTIONS: UTILITY TO CUSTOMER AND METER

Table F.5

1. These cost estimates are intended only to indicate the approximate variation in communication options. More detailed estimates should be prepared for major decisions. All costs are in current dollars--1982 dollars for 1982 and 1990 dollars for 1990. A general inflation rate of 8% per year is assumed from 1982 to 1990. Labor costs are assumed to rise at the inflation rate. Electro-mechanical components are assumed to rise at 5% per year. Solid State components are assumed to stay constant in price--technological developments will offset labor and materials price increases.

   The year 1990 is an arbitrary future year. To some extent, 1990 is time independent. It reflects a large scale program by the utility (200,000 points) and the estimated costs and reliability can be achieved in any year that this large scale program is achieved. To a greater extent, however, the 1990 estimates are time dependent. Technological developments outside the utility industry and "learning curve climbing" within the industry (by utilities and manufacturers) are necessary in the next eight years to achieve these cost and reliability figures.

2. Installed cost is the average cost per customer. Installed costs include acceptance testing, shop prep, field installation, and equipment costs for transmitters (injectors) and receivers.

3. System Reliability is reflected in two measures: annual failure rates and system performance percentage. Strictly speaking, failure rates should be component specific--the transmitter has a certain failure rate and the receiver has a failure rate. However, utilities have come to use failure rate in a system sense: they say X% of the receivers failed to perform and include transmitter and communication medium problems as well as receiver failures. Hence, annual failure rate is included here as a measure of system performance. For the electronic communication media in 1990 (radio, telephone, power line carrier, CATV), the transmitter and signal coverage problems are assumed to be significantly solved so that the failure rate listed in this table is in fact the receiver failure rate.

   System performance percentage is the annual average percentage of the customers (and/or meters) who receive

FOOTNOTES--Table F.5 (cont'd.)

the message they were supposed to receive.

4. Assume a clock calendar meter costs $25 to re-program and is re-programmed once every 5 years.

5. Assume a hand-held meter programmer costs $1600 and a meter reader covers 2700 meters per month.

6. Assume using the hand-held meter programmer adds 50% to the amount of time a meter reader needs to read the meter.

7. Assume dropping the price leaflet at the meter or other convenient location adds 10% to the meter reader's time.

8. Assume one letter a month at $.25 per letter.

9. Assume a $2,000,000 budget for display advertising in 5-10 major newspapers in the service area with 200,000 customers on the program. Conceivably the newspaper could display it for free as a public service like the weather forecast.

10. Assume $200 per phone answering machine and one answering machine per 1000 people as back-up to the newspaper, plus 100% overhead.

11. Assume two phone exchanges per answering machine (with multiple lines available in-house on each exchange) at $25/mo., plus 100% overhead.

12. The newspaper with phone answering machine as back-up are considered as the standard communication system. Public notices are required only in the newspaper (not also on TV or radio). However, not everyone reads the newspaper and the paper carrier does not always deliver. A phone answering machine should be adequate back-up.

13. If the utility were required to pay for advertising on TV, radio, and/or CATV with 200,000 customers, the costs could exceed $100 per year per customer. An intelligent strategy would be to have the information available to the public in the newspapers and via a telephone answering service. Then the TV, radio and CATV news reports would want to carry the utility price forecasts (like the weather forecast) at no charge to the utility so that the broadcaster could attract viewers/listeners.

14. Assumes a $480 installed cost of an automatic dialer with a pre-recorded voice stating the prices in effect the next day. Dialer has capacity of 60 numbers. For 1990, assume installed cost is the same and dialer capacity is 500 numbers. Customer answering machine costs are ignored.

FOOTNOTES--Table F.5 (cont'd.)

15. Assume $.05 per phone call times 365 calls per year, plus some staff time in 1982. In 1990, the utility should get a discount rate--especially if it calls at night, off-peak.

16. The $400 estimate for the direct dial network includes installed costs of $250 for modem, $50 for phone line and $100 for the data interface between the modem and the meter or customer's terminal. Add an additional $50 for leaseline. The utility may choose to have the phone company bear these costs--in which case the O&M costs would go up accordingly.

    In 1990, the modem and data interface are assumed to be housed inside the meter or customer terminal; hence, the $150 estimate.

    Note that for the phone communication medium, the customer to utility communication link comes at no incremental cost.

17. The $180 estimate includes about $140 for the monthly line charge and $30 for the Data Access Arrangement plus $10 in overhead. Add $150 for lease line. In 1990, the price will be determined by the phone company's interest in this market and what the competition to the phone company is.

18. Utilities' experience to date with phone equipment failure rates has varied from less than 1% to over 10%. The less than 1% has been experienced by utilities in conventional lease line applications such as SCADA. The over 10% has been experienced with new direct dial applications such as load control and remote meter reading. Overall, phone equipment is very reliable and will be very reliable for those applications that receive a full commitment from the phone company and the electric utility.

19. Even in those applications in which the phone equipment has had 10% annual failure rates, the system performance still exceeded 99%. The reason is that the return communication link allows failures to be quickly detected and repaired. For example, if a failure is detected and repaired within a month, then 10 of 100 receivers failing in a year means for only 10 months of 1200 receiver-months is service not provided.

20. Utilities have not extensively used radio receivers to communicate with customers or meters to date. Mainly they have cycled air conditioners and water heaters. This cycling experience is used to estimate the experience of communicating with customer or meter.

FOOTNOTES--Table F.5 (cont'd.)

The receiver price, including the share of the transmitter price, in 1982 is assumed to be $55-80 for AM/FM commercial broadcast carriers, depending on order quantities. Add $10 for VHF receivers. The installation cost, including acceptance testing and shop prep, is assumed to be $60. This is less than the $90 ($60 installation, $30 acceptance testing) experienced with residential air conditioner control applications. This $60 is justified because the receiver will be installed as part of the meter and no expertise (such as understanding air conditioning thermostat wiring) is required. Moreover, for communicating with the customer an installation cost approximating $0 is plausible--the customer is given a portable radio (with the appropriate lights or LED display to show price changes) at the time he or she signs up for the rate.

In 1990, the receiver price, including the share of transmitter price, is assumed to be $30 for AM/FM commercial broadcast carriers. Add $10 for VHF receivers. The receiver for meters is assumed to be packaged inside the meter and not need any separate housing. The receiver for customers will be packaged as any simple AM/FM radio. Installation cost is $0. As part of the meter, the receiver is installed with the meter at no incremental installation cost. If communicating with the customer, the customer picks up the portable receiver at rate sign-up time and places ("installs") it wherever he wants it in his house.

Note the similarities between this discussion of packaging the receiver with the meter and SCE's experience in developing the Demand Subscription Service Device.

21. O&M procedures are assumed to be to repair or replace the receiver as a failure is detected. The billing computer is used to detect any abnormalities in the customer's use that month and to flag a "repair person" to check the meter/receiver. Most failures of the customer's receiver will be reported to the utility by the customer. The O&M cost due to receiver repair is assumed to equal: (failure rate) x (receiver price + service call cost). In 1982, the service call cost is $50 (in 1990, $87.50).

22. Utilities today typically report failure rates of 10% or higher. Some manufacturers contend that only half of that failure rate is due to the receiver itself. The other half, they contend, is due to signal problems. Utilities and manufacturers agree that failure rates of 2%, as typically experienced by commercial broadcast receivers, is likely for 1990.

23. Even today with failure rates of 10% or higher, a system performance exceeding 99% can be achieved. By coupling

FOOTNOTES--Table F.5 (cont'd.)

the receiver to the meter, most communication system problems influencing the meter register switching will be detected by the billing computer which will flag for a repair person. Assuming one month elapses from failure occurrence to failure repair, then 10 of 100 receivers failing a year means for only 10 months of 1200 receiver-months is service not provided: system performance of 99.2%. By 1990, the system performance should be even higher.

24. A "ripple" power line carrier system is one that operates from 50-1000 Hz. "Other" power line carrier systems usually operate in the 6-10 kHz range. Today "other" systems can be used for reverse communication from the customer to the utility, but "ripple" systems cannot (see Table 7).

    The cost and reliability assumptions for radio systems generally apply to the power line carrier systems with the following two exceptions. First, power line carrier systems require signal injectors at each distribution substation. Thus, the installed cost per customer/meter is very sensitive to the number of receivers per injector. Second, ripple communication systems have proven their reliability in Europe and in their U.S. applications thus far. The real question is their relative cost.

25. Cable TV is only recently being considered as a utility communication medium. Its current disadvantage to PG&E and SCE is its relatively low saturation. Although the CATV company will probably bear the incremental capital costs for electric utility use, it is unclear what rates will be charged for this service.

to communicate the price change and to whom (meter or customer). Five time spans, ranging from over 1 year to under 5 minutes, are examined. Of course, any communication medium that can communicate in under 5 minutes is also capable of communicating if allowed over a year to communicate.

The equipment option listed for over one year time span is meter shop staff. That is, as for today's time of use rates, if the utility can predetermine the price period changes far enough in advance, it can use the meter shop staff to program these price period changes into the meter. Today, time-of-use price periods are programmed in typically for 5 years. If the price period definitions are changed more frequently than that, then a larger number of appropriately trained metershop staff will be required. At some frequency (perhaps once a year), this approach becomes too costly.

If price changes are known more than 1 month in advance, then the meter reader can be used to communicate to the meter (through a hand held programmer) or to the customer (through a leaflet left at the house). If the utility has over 2 days, then it can use the mail to communicate the price changes to the customer.

If the utility has over 12 hours to communicate the price change to the customer, it can use most of today's existing commercial broadcast media. Examples of these include the newspaper, TV news, radio news, etc. The least costly alternative would be the use of the newspaper to post the prices. As not everyone receives a newspaper and the paper is not always delivered, the utility would want to provide a telephone backup of the customer calling a local or toll-free number to get the price information. The cost estimates here--$10 per customer in 1982--assumes the utility has to pay full commercial advertising rates. If the utility can get the newspapers to publish the rate information as a public service the way the weather forecasts are published, then the utility could conceivably pay nothing. If the utility has to pay full commercial rates for TV news broadcasting, then the TV is not a cost-effective communication medium alternative. Hopefully, TV stations will want to carry the utility rate information as a way of attracting additional viewers and hence will not charge the utilities for this advertising service.

If the utility wishes to communicate to the customer or meter in less than 5 minutes notice, then it needs a special electronic communication link. These options include telephone, radio, powerline carrier and cable TV. Unless the phone company changes its pricing strategy, a phone communication link would be cost-effective only for the larger customers with more sophisticated rates for when the higher data reliability is worth the cost. Radio and power line carrier are the most likely alternatives for mass broadcasts to small to medium customers since cable TV does not experience a very high saturation yet.

Most of the electronic communication systems are currently experiencing about 10% annual failure rates. The exception to this are the "ripple" systems and phone systems that use a separate line than the customer's existing phone line. However, even with these high failure rates, a relatively high system performance can be achieved for spot pricing transactions, if the communication receiver is coupled with the meter. When the communication receiver fails, the meter would not switch "registers" appropriately and the billing computer will flag that customer's data as abnormal. In relatively short time, no more than 1 month, the receiver failures should be detected and corrected. This failure detection capability is certainly one advantage of price transactions versus direct appliance control.

F.3.2. Metering

Table F.6 summarizes the cost and reliability estimates of metering equipment. Its left hand column gives the metering functional requirement of number of values stored between meter readings. The next columns list the equipment options capable of meeting that functional requirement and the cost and failure rates experienced with those equipment options. Six functional requirements, ranging from 1 value stored per meter reading to 288 values stored per day between readings, are examined. Of course any equipment capable of storing 288 values per day between meter readings is also capable of storing one value between meter readings.

The first significant observation is that meters with electromechanical registers can adequately store up to 1, 2, or 3 values between meter readings. Beyond 3 values, some electronic permanent storage (either non-volatile memory such as EPROMs--Electrically Programmable Read Only Memory--or volatile memory with battery backup) or magnetic tapes must be used. By 1990, electronic permanent storage meters are seen to be cost competitive with electromechanical register meters for recording even 2 or 3 values.

Another observation is that for certain functional requirements equipment costs will be much higher today than in 1990 because no equipment has been tailored to that function. In particular, today to store 2 to 3 or 24 values per day (60-90 or 720 values per billing month), a load survey recorder is required. By 1990, if these rates were to become widely used, these costs would drop by 2 or 3-fold.

The third observation is that today's appropriately sized electronic permanent storage meters (in this table 288 per day and 3+) will be the same price in 1990 dollars that they are in 1982 dollars. Technological developments offset

TABLE F.6

METERING EQUIPMENT OPTIONS[1]

Functional Requirement: Number of Values Stored Between Meter Readings	Equipment Options	Installed Cost[2,3] 1982	Installed Cost[2,3] 1990[7]	O&M Cost[2,4,5] 1982	O&M Cost[2,4,5] 1990[7]	Annual Failure[6] Rates (%) 1982	Annual Failure[6] Rates (%) 1990[7]
1. 1	One Electro-Mechanical Register						
	Single Phase	38	60	.10	.18	0.5	0.5
	Three Phase	150-240[8]	240-360[8]	3	5	1.0	1.0
2. 2-3	Two to Three E-M Registers						
	Single Phase	240	365[9]	12	4	10	2
	Three Phase	350-440	560-680	18	11	10	2
3. 3+	Electronic Permanent Storage[10]						
	Single Phase	365	365[9]	18	4	10	2
	Three Phase	480-570	560-680	25	11	10	2
4. 2-3 per day	Elec. Perm. Storage, 30 days[11]						
	Single Phase	1200-1500[12]	450	60-75	5	10	2
	Three Phase	1300-1600	650-850	65-80	13-17	10	2
5. 24 per day	Elec. Perm. Storage, 30 days[11]						
	Single Phase	1200-1500[12]	600	60-75	6	10	2
	Three Phase	1300-1600	800-1000	65-80	16-20	10	2
6. 288 per day	a) Elec. Perm. Storage, 30 days						
	Single Phase	1200-1500	1200-1500[10]	60-75	12-15	10	2
	Three Phase	1300-1600	1300-1600	65-80	26-32	10	2
	b) Magnetic Tape						
	Single Phase	830	1200	25-50[4]	30[4]	6-12	5
	Three Phase	920-1000	1300-1600	28-60	65-80	6-12	5
	c) Elec. Perm. Storage, 2 days[11] Plus Communications Link						
	Single Phase	1200-1500*	450*	60-75*[4]	5*[4]	10	2
	Three Phase	1300-1600*	650-850*	65-80*	13-17*	10	2

*Plus Communications Link

FOOTNOTES

METERING EQUIPMENT OPTIONS

Table F.6

1. All metering equipment options are assumed to have the conventional, rotating watt-hour disc as the measurement sensors. Solid-state measurement sensor could become significantly present by 1990. However, since the application of spot pricing is not dependent on the meter's measurement technique, solid state measurement developments are ignored.

2. These cost estimates are intended only to indicate the approximate variation in metering options. More detailed estimates should be prepared for major decisions. All costs are in current dollars--1982 dollars for 1982 and 1990 dollars for 1990. A general inflation rate of 8% per year is assumed from 1982 to 1990. Labor costs are assumed to rise at the inflation rate. Electro-mechanical components are assumed to rise at 5% per year. Solid state components--mainly memory--are assumed to stay constant in price--technological developments will offset labor and materials price increases.

3. Installed costs include acceptance testing and shop prep costs as well as field installation and equipment costs. These costs are averaged over all meters even though some meters may not incur some of the costs (e.g. acceptance testing costs).

4. Operation & Maintenance cost includes preventive maintenance and testing as well as failure repair costs. (For single phase, single register meters there is no preventive maintenance.) However, meter reading cost (including the translation of magnetic tapes) is <u>not</u> included here. It is in Table F.7.

5. Other than single register meters and magnetic tape recorders, the utilities have little experience to estimate the O&M costs for the meters. For these meters the O&M costs in 1982 are assumed to equal (installed cost x 50% x failure rate). Under this assumption a new meter is installed to replace each failed meter and the failed meter can be repaired at half the installed cost for re-use. In 1990, the same assumption is applied to single phase meters. But for three phase meters in 1990 the utilities are assumed to have a systematic testing program of meters so that total O&M cost equals (installed cost x failure rate)--which means about 1 hour is spent testing 10-15% of the meters each year.

6. The failure rates given here for 1982 are based more on

FOOTNOTES--Table F.6 (cont'd)

utility estimates than the lower manufacturer estimates. Utility and manufacturer personnel essentially agreed on 1990 failure rates.

7. The year 1990 is an arbitrary future year. To some extent, 1990 is time independent. It reflects a large scale program by the utility (200,000 points except for 288-per-day meter storage requirement programs) and the estimated costs and failure rates can be achieved in any year that this large scale program is achieved. To a greater extent, however, the 1990 estimates are time dependent. Technological developments outside the utility industry and "learning curve climbing" within the industry (by utilities and manufacturers) are necessary in the next eight years to achieve these cost and reliability figures.

8. The range in price estimates and three phase meters reflects the variation in size and type of the meter service entrances.

9. In 1982, a 100% sample is assumed for acceptance testing of all single phase meters except the conventional single register meter. In 1990, a 10% sample is assumed for acceptance testing of all single phase meters. For three phase meters a 100% sample for acceptance testing is always assumed. This acceptance testing change explains why the installed cost of single phase meters rises proportionately less than for three phase meters.

10. Electronic Permanent Storage includes all electronic means of storing data from RAM with battery back-up through bubble memory to EPROM. The cost reductions in non-volatile memory assumed here by 1990 may seem conservative. However, not enough development money outside the utility industry is being put into non-violatile memory (e.g., the bubble memory) to achieve the order of magnitude cost reductions seen in volatile memory in the 1970's.

11. Of course, the magnetic tape recorder is an equipment option for storing 60-90 values (2-3 per day for 30 days) or 720 values (24 per day for 30 days). However, the costs and failure rates for storing these values is not seen to be significantly different than the costs and failure rates for storing 8640 values (288 per day for 30 days). Hence, the magnetic tape recorder is not listed here.

12. No meter is available today that can electronically store 60-90 values (2-3 per day for 30 days) or 720 values (24 per day for 30 days). Thus, the electronic recorder used

FOOTNOTES--Table F.6 (cont'd.)

to store 8640 values (288 per day for 30 days) must be the electronic option used in 1982 to store 60-90 or 720 values. However, by 1990 meters can be developed whose capabilities match the 60-90 and 720 value storage requirements.

materials and labor costs increases.

A fourth observation is that the failure rates being experienced today (10%) and the failure rates anticipated in 1990 (2%) will never be as low as the failure rates being experienced with single register meters (0.5-1%). Thus, O&M costs will be higher. However, this does not also mean that the reliability of the billing data will be lower. As an example, note that the magnetic tape recorders used today have considerably higher failure rates (6-12%) than the single register meters. However, due to the error detection and correction in the translators and billing computers and the quick repair of failed units, the total system performance exceeds 99%. The same thing should happen with electronic permanent storage meters today and in the future.

F.3.3. Communication from Meter to Utility Billing Computer

Table F.7 summarizes the cost and reliability of communicating the meter data to the utility's billing computer. The lefthand column lists the equipment options for this communication. The second set of columns shows the annualized costs of these meter reading options. And the third set of columns shows the system performance (as a percentage of good, usable data).

Equipment options listed range from using the existing meter reading book through the magnetic tape and electronic chip through using the meter itself as a billing computer. Costs and performance information are not estimated for the meter as the billing computer and for the portable billing computer options--they are just listed here for completeness.

The meter reader book is by far the cheapest option, when applicable. However, if the data volume exceeds several values, then other media must be considered to carry the meter data back to the billing computer.

System performance is shown "without error correction" and "with error correction." The system performance with error correction is the one really of interest. However, people are often misled by focusing on system performance without error correction. By looking at this chart, we see that without error correction the meter reader book is actually a less reliable medium than the electronic chip, a potential candidate for larger volumes of data under spot pricing. Thus the somewhat lower reliability experienced by more sophisticated time of use meters is somewhat mitigated against by the increased reliability of the communication medium (electronic chip) for carrying this data back to the billing computer. In the end, with the error detection and correction capability in the billing computer, a reliable system can be made from almost any configuration of meter and meter reading components.

TABLE F.7

COMMUNICATION EQUIPMENT OPTIONS:
METER TO UTILITY BILLING COMPUTER

Equipment Option	Annualized Cost[1,2]		System Performance (%)[3] No Error Correction		Error Correction	
	1982	1990	1982	1990	1982	1990
1. Meter Reader Book						
a) One Value	42	74	97+	97+	99+	99+
b) Several Values	54	95	97+	97+	99+	99+
2. Magnetic Tape	540	945	97	97	99+	99+
3. Electronic Chip	132	231	98	99	99+	99+
4. Portable Electronic Meter Reader	132	231	98	99	99+	99+
5. Electronic						
a) Telephone	66	116[4]	90-95	98	95-99[6]	99+
b) Radio, UHF	--	231[5]	--	?	88+[6]	?
c) Powerline Carrier	132	231[5]	--	?	80+[6]	?
6. Portable Billing[7] Computer						
7. Meter as Billing[7] Computer						

FOOTNOTES

COMMUNICATION EQUIPMENT OPTIONS: METER TO UTILITY BILLING COMPUTER

Table F.7

1. These cost estimates are intended only to indicate the approximate variation in communication options. More detailed estimates should be prepared for major decisions. All costs are in current dollars--1982 dollars for 1982 and 1990 dollars for 1990. A general inflation rate of 8% per year is assumed from 1982 to 1990. Labor costs are assumed to rise at the inflation rate. Electro-mechanical components are assumed to rise at 5% per year. Solid state components are assumed to stay constant in price--technological developments will offset labor and materials price increases.

   The year 1990 is an arbitrary future year. To some extent 1990 is time independent. It reflects a large scale program by the utility (200,000 points) and the estimated costs and reliability can be achieved in any year that this large scale program is achieved. To a greater extent, however, the 1990 estimates are time dependent. Technological developments outside the utility industry and "learning curve climbing" within the industry (by utilities and manufacturers) are necessary in the next eight years to achieve these cost and reliability figures.

2. These cost estimates reflect all costs from reading the meter up to printing the bill. These cost estimates probably better reflect the overhead costs than the cost estimates in Tables F.5 and F.6.

3. System performance is measured as the percent of meter data that is good or usable for billing. This percent reflects failures experienced in the meters as well as meter reading errors. It also reflects usage data that has been flagged by the computer as being abnormal and turns out to be okay. System performance is presented with and without error correction to highlight the fact that metered data has not been (and does not have to be) "perfect" to get reliable bills. The billing system can and does correct errors.

4. This cost does not include the customer terminal cost and phone company tariffs. Those costs are included in Table F.5 as costs of establishing the communication link out to the customer.

5. These costs equal the data processing costs of the phone

FOOTNOTES--Table F.7 (cont'd)

system plus $66 annual incremental cost for the return communication link in 1982 and 1990.

6. These system performance numbers represent the experience of the EPRI-DOE demonstration projects. The equipment in these projects was prototype and equipment used in the near future should have a higher system performance. In particular, telephone systems are being used for distribution automation control that have 99+% system performances.

7. These options are listed for completeness but gathering the cost and reliability data was deemed beyond the scope of this study.

F.3.4. Summary of Spot Pricing System Costs

In the previous sections the cost of meeting the different functional requirements of each of the five components of the communication metering system for implementing spot pricing were identified. In this section, these component costs are added together to compute a total system cost for each type of transaction. Since not explicitly covered in the previous sections, the direct appliance control and demand subscription service transaction costs are also computed here.

Table F.8, or a more refined revision of it, can be used to help select what transaction is appropriate for a particular customer or customer group. The cost of the system supporting the rate or transaction which the customer has today is compared to the costs of the system of the rate or transaction contemplated for that customer. If the difference in these two systems' costs is less than the benefits of moving to the other rate, then that customer should move to the rate or transaction being contemplated. For example, if the customer is on a conventional flat rate for 1982 and is considering choosing the conventional time of use rate in 1982, then the benefits of moving to the time of use rate would have to exceed $100 ($150 minus $50--see costs in Table F.8) each year. The question of what should be included as benefits (kw reduction only or also reduction in intraclass subsidization from a rate structure that better reflects cost) and measurement of those benefits are left for another discussion.

Several observations of Table F.3 should be highlighted. First, note that even for the most costly system--the 5 minute pricing--only 13 kw of load reduction (assuming 1 kw year costs $80) is necessary to justify moving from the flat rate to the most sophisticated rate. By 1990 this drops to 5 kw. Almost any customer over 100 kw of demand would qualify. However, few customers over 100 kw of demand would be able to respond to 5 minute varying prices. Thus, except for the smallest customers, the ability of the customer to understand and respond to the rate seems to be more of a constraint than equipment costs in determining what rate commercial customers should be on.

The second observation is that all transaction systems with the exception of the conventional flat rate decline in costs (in real dollars) from 1982 to 1990. The third observation is that some transaction systems decline in cost significantly more than others.

TABLE F.8

SPOT PRICING SYSTEM COSTS

Transaction Number & Example	Annualized Costs, 1982[1,2] 1982$	Annualized Costs, 1990[1,2] 1982$	Equipment Option Selected[3] Communication to: Customer	Meter	Billing Computer	Meter
1,9 Conventional Flat Rate	50	50	3	-	1a	1
2,10 Conventional TOU Rate	150	125	3	1	1b	2
3,11 Curtaillable Rate 12 Hour Notice Fixed Length Curtailment	210	140	4a	5b	1b	2
4,12 Conventional TOU Rate Except Prices Can Change Each Day	650	225	4a	-	3,4	4
5,13 Curtaillable Rate 12 Hour Notice Variable Length Curtailment	210	140	4a	5b	1b	2
6,14 TOU Rate Prices Vary by Hour 12 Hour Notice	650	250	4a	-	3,4	5
7,15 Curtaillable Rate 5 Minute Notice Variable Length Curtailment	250	140	5b	5b	1b	2
8,16 TOU Rate Prices Vary Every 5 Minutes 5 Minute Notice	900	350	5a	-	5a	6c
17 Direct Appliance Control	130[4]	90[5]	3	5b Appliance	1a	1
18 Demand Subscription Service	180[6]	135[7]	5c	5b	1a	1

FOOTNOTES

SPOT PRICING SYSTEM COSTS

Table F.8

1. These costs are the total costs, capital and expense, on an annualized basis, of the communication-metering system required to implement these transactions. This system contains five main functions: a) communicating the forecasted prize from the utility to the customer, b) communicating the actual price from the utility to the customer, c) communicating a price period change from the utility to the meter, d) metering the electricity use for each price period, and e) communicating the electricity use from the meter to the billing computer. These costs are taken from Tables F.5, F.6 and F.7 by applying the following assumptions: discounting from 1990$ to 1982$ using 8% inflation; a fixed charge rate of 20% (reflecting an 18% cost of money and 30 year life) is used for single register meter capital costs; a fixed charge rate of 33% (reflecting an 18% cost of money and 10 year life) is used for all other capital costs. These cost estimates are approximate--they are intended to indicate the range of cost variation among transactions. More detailed estimates should be prepared for major decisions.

2. These costs assume single phase meters. Add $40-70 for systems using three phase meters.

3. The four columns under this caption, "Equipment Option Selected" represent the five components of the spot pricing system. (The equipment for communicating the forecasted price is assumed to be the same as for communicating the actual price.) Each number in these columns represents the number in Tables F.5, F.6, or F.7 of the equipment option selected in this cost table to be the system component for the transaction in that row of the table. For example, transaction 2, a conventional TOU Rate, has #3 equipment option for communicating to the customer. In Table F.5, option #3 is "Mail." Equipment option #1 is used to communicate to the meter. In Table F.5, option #1 is "Meter Shop Staff." Equipment option #1b is used to communicate with the billing computer. In Table F.7, option #1b is "Meter Reader Book--Several Values." Equipment option #2 is used for the meter. In Table F.6, option #2 is "Two/Three Electro-Mechanical Registers."

4. The installed costs of direct appliance control is assumed to be $170 in 1982 ($80 for receiver, $30 for acceptance testing and shop prep, $60 for installation). O&M costs in 1982 are assumed to be $17 for failure repairs-- (10% failure rate) x ($170)--plus $9 for failure detection--$20 per receiver check on an average 46% per year of receivers

FOOTNOTES--Table F.8 (cont'd)

(20% the first year, 20% the second year, and 100% the third year). Total annualized cost is \$132 = 170 (.33) + 17 + 9 + 50, where \$50 is the cost of reading the single register meter.

5. The installed cost in 1990 is assumed to be \$200 (\$80 for receiver, \$120 for acceptance testing, shop prep, and installation). O&M cost is assumed to be \$4 for failure repairs--(2% failure rate) x (\$200)--plus \$7 for failure detection--\$35 per receiver check on an average 20% per year of receivers. (Note: the lower failure rate almost eliminates the need for a 100% test until the end of receiver life). Total annualized cost in 1990\$ excluding meter reading is \$77 = 200 (.33) + 4 + 7. Discounted to 1982\$ and adding meter reading gives \$92 cost.

6. The installed cost of a Demand Subscription Service Device in 1982 is assumed to be \$340 (\$300 price plus \$40 for acceptance testing, shop prep, and installation). O&M costs are assumed to be \$17 for failure repairs--(10% failure rate) x (\$340 x 50%)--plus \$3 for failure detection--incremental cost of meter reader's time to check failure indication lights. Total annualized cost, including meter reading is \$182 = 340 (.33) + 17 + 3 + 50.

7. The installed cost of a Demand Subscription Service Device in 1990 is \$430 (\$360 price plus \$70 for acceptance testing, shop prep, and installation). O&M cost is assumed to be \$4 for failure repairs--(2% failure rate) x (\$430 x 50%)--plus \$5 for failure detection. Total annualuized cost in 1990\$, excluding meter reading, is \$151 = 430 (.33) + 4 + 5. Discounted to 1982\$ and adding meter reading gives \$132.

TEXT FOOTNOTES

1. The reader will note that this transaction is comparable to the conventional curtailable rate except that a 12 hour notice is provided, the notice is provided through the newspaper rather than over the telephone. This transaction is also similar to the demand subscription service rate except that the newspaper rather than customer alert device is used to notify the customer of the curtailment, the customer is provided a longer notice of the impending curtailment, and a meter rather than circuit breaker is used to enforce (monitor) compliance. The reader will also note that the Price Only counterpart to this transaction would have the newspaper carrying the message to the customer that the high price would be in effect from noon to 6 that day rather than the message that the critical period would be in effect that day.

2. It is possible to define a larger communication-metering system. Such a definition would then include communicating the bill to the customer and the customer's transfer of funds back to the utility. In these days of electronic funds transfers, a utility selecting a more sophisticated customer interface system than today's meter would want to consider these two additional functions on the communication-metering system. However, since these additional functions are not particularly germaine to the spot pricing analysis, they have been omitted in this discussion.

3. To be sure the more frequently a meter is read the less storage is required at the meter. However, frequent/rapid meter reading is <u>not required</u> to make spot pricing work.

4. For both transaction 7 and 15, utility does not need to communicate with the meter if the meter will store 288 values each day of the billing month so that the utility can then use its billing computer to match the critical condition time period with the customer's usage during that time period. However, as seen in Section F.3, storing 288 values per day with no communication link is a much more expensive alternative.

5. If the utility or PUC decides it needs a real time verification that the customer has received the correct price signal, then an electronic two-way communication medium is required.

APPENDIX G

GLOSSARY OF TERMS

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GLOSSARY OF TERMS

Cross-Subsidies: Refers to the distribution of the costs of electricity services among customers. Those customers who pay an amount exceeding the cost imposed by their consumption are subsidising other customers and vice-versa. Cross-subsidies may exist within a customer class as well as across customer classes.

Customer Control: There are two ways in which demand control may be exercised: Customer control--Control is exercised by customer at the end use; and Utility Control--Control is exercised by the utility to implement the customer's decisions.

Customer Decision: The decisions taken by the customer concerning their desired response to various levels of spot price based rates. On the basis of this decision customers can exercise control themselves or use available "Utility Control" services. See also "Customer Control" and "Utility Control".

Customer Price Forecast Services: The services offered by the utility or independent firms in providing short, medium and long-term forecasts of spot price based rates. These forecasts are used for operations and investment planning.

Cycle Length: The length of time between spot price updates.

Demand Resonse Model: A model yielding estimates of demand response to various levels of spot price based rates.

Demand Subscription Services (DSS), Group Load Curtailment (GLC) and COOP Programs: Load management programs established by PG&E and SCE which consist of an agreement by participating customers to observe a prespecified maximum demand level when the utility calls for it. Participating customers see a lower cost of electricity since they limit their consumption at times of supply shortages associated with high generating or economy interchange costs.

Futures Market: Market which provides risk sharing among customers, the utility and other interested agents. It provides for forward contracts consisting of a fixed quantity, fixed price agreement pertaining to a future point in time.

Homeostatic Control: The cooperation of the Utility and its customers through enhanced communication of information on spatial and time varying costs. Behaviour of all participants (utility and customers) is adjusted in the interest of mutual benefits. Derived from the biological term "Homeostasis" denoting the state of mutually beneficial equilibrium achieved by the various parts of an organism.

Number of Levels: Number of price levels within a given period. May be finite (1, 2, 3, etc.) or continuous.

Number of Periods Within a Cycle: The number of time blocks for which prices are set. At least one per cycle.

Phase, Experimental: The first phase of the spot price implementation plan consisting of a range of experimental rates implemented on a limited number of customers. It is expected to last three years.

Phase, Full Implemenation: The third and last phase of the spot price implementation plan, characterized by mandatory spot price based rates with a number of options available to customers. Utility operations will be fully integrated with the process of rate setting and communication.

Phase, Initial Imlplementation: The second phase of the spot price implementation plan to last another three years. Spot price based rates will be offered on a voluntary basis to a large number of customers following regulatory approval and successful completion of the experimental phase.

Price Only Transactions: Spot price based rates that allow customers to use all the energy they desire, at the quoted price. The prices are set so that they reflect, to the extent allowed by advance notice requirements, the actual system marginal costs and the cost to both the utility and its customers of maintaining a desired reserve margin.

Price/Quantity Transactions: Contracts for electricity service involving quantity ceilings. Customers, instead of seeing high prices when low reserve margins are expected, contract a priori to reduce their usage when necessary to agreed-upon levels. Overriding quantity ceilings at a specified cost may be allowed.

Quality of Supply Component: One component of the spot price which accounts for the scarcity value of electrical energy to customers. The quality of supply component is zero as long as demand does not closely approach the capacity limit of the system. It becomes positive as capacity becomes scarce and thus it reflects the value of electricity to the customer.

Reserve Margin: The generating capacity (direct or via tie-lines) available at a certain moment in time over and above the generating capacity employed to serve demand.

Revenue Reconciliation: The adjustment of spot price based rates to achieve utility revenues yielding a "fair rate of return" to utility equity holders.

Spot Price Based Rates: Rates based on the expected value of the instantaneous spot price. They reflect incremental costs of providing electric energy and include quality of supply component to ensure that demand rationing is minimized.

Spot Price Duration Curve: Analogous to a load duration curve with the y axis representative of the probability of the spot price exceeding a given level.

Spot Price, 24 Hour: The spot price based rate that varies every hour (24 Periods within each cycle) but is calculated and communicated once per day (cycle length is one day).

Spot Price, Component Related to Transmission and Distribution: A component added to incremental costs and the quality of supply component to reflect the marginal contribution to T&D losses and T&D constraints (line over loads, voltage excursions etc.) of a particular demand center (location and voltage level both matter).

Spot Price, Full Adoption: That time at which the utility and the regulatory agency aggree that all future rates and load management procedures will be based on the spot price concept.

Spot Price, Instantaneous: The instantaneous marginal cost of electrical generation corrected for losses and any quality of supply adjustments.

Spot Price, One Hour: The spot price based rate that is calculated and updated every hour.

Spot Price, One Month: The spot price based rate calculated and communicated every month. May include one or more pricing periods.

UMACS, Universal Meter and Control System: A system which can be programmed and adopted to respond to all (price only and combined price/quantity) spot price based signals from the utility to the customer.

Utility Control: The service offered by utilities to customers who do not want to be involved in constantly controlling their loads in response to changing spot price based rates. See also "Customer Control" and "Customer Decision".

Utility Provided Control Services: See "Utility Control".

Value of Service Model: A model yielding an estimate of the value of incremental electricity service to customers as perceived by the customers. Employed for estimating the value of the quality if supply component of the spot price.