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NEW ELECTRIC UTILITY MANAGEMENT AND CONTROL SYSTEMS

Proceedings of Conference,
held in Boxborough, Massachusetts
May 30 - June 1, 1979

by the Homeostatic Control Study Group

MIT Energy Laboratory Technical Report
No. MIT-EL-79-024

This work was supported by the Center for Energy Policy Research and the Electric Power Systems Engineering Laboratory of the Massachusetts Institute of Technology.

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Foreword

The 1979 New Electric Utility Management and Control Systems Conference held May 30- June 1 was the first such conference devoted to the potential of Homeostatic Control as a mechanism to provide greater economic and physical efficiency in future electic supply and demand. The papers contained herein provide the background to the concepts of Homeostatic Control. Chapters II, III, IV and V open with a concept paper followed by a summary of the discussion evolved from the conference participants. Thus, these proceedings provide an initial critical review of the Homeostatic Control concepts.

These proceedings are divided into six chapters, followed by a set of appendices. The subjects covered are as follows:

Chapter 1 contains a discussion of the purpose of the conference and its organization. It also conatins a preprint of "Homeostatic Utility Control," presented at the IEEE PAS 1979 Summer Power Meeting, which provides a self-contained description of the major aspects of Homeostatic Control.

Chapter 2 contains discussions on the economic principles involved in the pricing of electricity and how these principles may be reflected in time varying buy and buy-back spot prices.

Chapter 3 contains discussions on utility-customer information flows and on how customers can respond to various types of pricing and control mechanisms.

Chapter 4 contains discussions of the problems of regulatory commissions and agencies in setting rates and the effects new control concepts may have on these issues.

Chapter 5 contains a review of some of the problems associated with the operation of electric power systems and discussions on how such quality of supply issues can affect economically based buy and buy-back spot prices and can lead to a need for an interruptible spot price. The homeostatic Frequency Adaptive Power Energy Rescheduler (FAPER) concept which allows customers to actively participate in system control without affecting their own needs is discussed.

Chapter 6 provides an edited version of the proceedings of the Critical Issues Panel which summarizes the discussion during the four conference presentations.

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CONFERENCE ON NEW ELECTRIC UTILITY
MANAGEMENT AND CONTROL SYSTEMS

Sheraton Inn
Boxborough, Massachusetts

May 30 (Wednesday)	Agenda
3:00-6:00	CEPR Associates meeting (Associates Representatives only-Patio Room)
5:00-7:30	Other participants arrival and registration
6:30-7:30	Open bar (poolside)
7:30-8:30	Dinner (poolside)
8:30-9:30	Introduction to Conference • Loren Cox An overview of electric power system problems and an introduction to homeostatic control • Fred Schweppe

May 31 (Thursday) - All day in Colonial Room

7:00-8:00	Breakfast (Harry's Tavern)
8:00-8:20	Issues in Management and Control of Electric Power Systems • Fred Schweppe
8:20-10:15	Pricing of Electric Power Initiator - Richard Tabors Comments - William Gillen - Douglas Bauer Moderator - Loren Cox
--Coffee--	
10:30-12:15	Customer Response Systems Initiator - James Kirtley Comments - Stephen Feldman - James Hunter Moderator - Loren Cox

12:15-1:00	Lunch
1:00-3:15	<u>The Utility Regulatory Environment</u> Initiator - Paul Levy Comments - Ernst Habicht - Haskell Wald Moderator - Loren Cox
--Coffee--	
3:30-5:30	<u>System Control and Quality of Supply</u> Initiators - Hugh Outhred - George Verghese Comments - David Hayward - Thomas Dy Liacco Moderator - Loren Cox
5:30	Hardware demonstration
6:30-8:30	Open bar (poolside)
	Dinner (Colonial Room)

<u>June 1 (Friday)</u> - All meetings in Colonial Room

7:30-8:00	Continental breakfast
8:00-10:00	<u>Critical Issues Panel</u> Chair - David White Panel - Richard Bower - Paul Dandeno - Theodore Eck - Lawrence Linden
10:00-10:30	Coffee and check out
10:30-12:00	Future Directions and Conclusions
12:00	Lunch

Chapter 1: Introduction and Summary

1.1 Purpose of the Conference

The purpose of this conference is to explore issues related to operation and rate making for electric power systems. Rapid changes in costs, environmental concerns, and generation and conservation technologies provide an impetus to find new approaches for addressing these issues.

The major focus of the conference will be on the relationship between radically new, technologically motivated approaches, and the regulatory process, which influences those approaches that are actually adopted. An MIT group has developed a new technological approach, called Homeostatic Control for electric power systems operation and rate-making. Homeostatic Control concepts will provide the vehicle for exploring the relationship between new engineering and economic technologies and the regulatory process.

Homeostasis is a term used in biology relating to an "equilibrium or a tendency toward equilibrium between associated but independent elements of an organism..." When the term homeostatic control is used in this conference, the overall electric power system is viewed as the "organism" whose "associated but independent elements" consist of the utility and all of the customers. The main feature that differentiates Homeostatic Control from other approaches to power system operations and rate-making is the exploitation of advances in communications and computer technology which allow nearly instantaneous information flows to occur between the utility and the customers. This continuous information flow allows for the maintenance of an improved equilibrium between producer costs and user demand. This equilibruim is based on concerns for equity and economic efficiency in concert with a stable, functioning power system. Homeostatic Control is a radical departure from present-day practices because price becomes an integral part of power systems control. It is a new perspective for rate-making policy in which there is an opportunity for prices to reflect the current costs as determined by whatever economic theory is adopted or policy objectives are desired.

The Homeostatic Control concept has the potential for enormous economic and social impact. Its implementation could result in better economic efficiency; a less vulnerable and more reliable power system, and enhanced opportunities for new technologies and alternative energy systems to compete on the basis of their actual merits. Although many aspects and ramifications of Homeostatic Control have not yet been fully explored, the MIT group has come to the point where it believes Homeostatic Control provides the basis for a control and pricing structure which meets the future needs of the nation.

There are many open technical economic and engineering questions which must be answered before a new concept such as Homeostatic Control can be implemented. Furthermore, Homeostatic Control need not be the only possible new approach to operation and rate-making for electric power systems. However, whether one is dealing with homeostatic control or some other approach, a critical factor lies in the regulatory process. Any new technology which is based on radical change in utility-customer relationships can be implemented only if it is coordinated through an evolving regulatory process.

Thus, even though the conference must be concerned with technical economic and engineering issues, it is expected that the interaction between what is technologically possible and what is acceptable in the regulatory process will be a major focus.

The conference is organized as follows: After dinner on Wednesday night, an admitted favorably biased description of the advantages of Homeostatic Control was made. The Thursday discussions used aspects of the Homeostatic Control concept as starting points for discussion on major issues in four areas; pricing/rate-making, customer response, regulation, and power system operation. Discussion in each areas starte with an MIT-prepared presentation detailing the issues as we see them, followed by two commentators who will make brief presentations on their own perspectives, ending with open discussion. Friday morning started with presentations on issues that Thursday's discussion showed to be unresolved or especially critical.

The conference concluded with discussion on possible future directions.

The proposals of the MIT group for immediate future action related to the Homeostatic Control concept are as follows:

1. Research on system-wide effects on economics/costs and control/stability/security.
2. Continued development of hardware.
3. Limited scale, carefully monitored test implementation.
4. Continued consideration of utility, customer, and regulatory adaptations necessary for implementation.

A paper which provides more details on the overall Homeostatic Control concept follows.

1.2 Significant Conclusions

- o The Homeostatic Control system would be most useful in applications in the industrial and large commercial sectors but could, over time, become a viable alternative for smaller consumers such as residences.
- o There are no insurmountable regulatory barriers to the adoption of Homeostatic Control.
- o The intent of the Public Utilities Regulatory Policy Act (PL 95-617) with regard to pricing, cogeneration and small generators is accurately reflected in the Homeostatic Control concepts, particularly in spot pricing.
- o The FAPER (Frequency Adaptive Power Energy Rescheduler) and possible a VAPER (Voltage) are likely to be able to play a significant role in increasing overall electric utility system reliability.
- o Further detailed analyses of the benefits to, and responsiveness of, consumers and utilities to the Homeostatic Control concepts should focus on the spot pricing system including timing and on the potential application areas for the FAPER.
- o The next major stage in the development of Homeostatic Control should be an experiment utilizing the concepts and involving all of the significant actors, a utility, a consumer, preferably an industry or large commercial customer with a large and flexible load and, significantly, a state Public Utility Commission.

HOMEOSTATIC UTILITY CONTROL

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Abstract - Distribution Automation and Control (DAC) systems have potentially major effects on costs, social impacts, and even on the nature of the power system itself, especially as dispersed storage, generation, and customer interaction become more prevalent. However, at the present time, it is not clear which particular modes of control will best exploit the capabilities of DAC. Homeostatic Utility Control is an overall concept which tries to maintain an internal equilibrium between supply and demand. Equilibrating forces are obtained over longer time scales (5 minutes and up) by economic principles through an Energy Marketplace using time-varying spot prices. Faster supply-demand balancing is obtained by employing "governor-type" action on certain types of loads using a Frequency Adaptive Power Energy Rescheduler (FAPER) to assist or even replace conventional turbine-governed systems and spinning reserve. Conventional metering is replaced by a Marketing Interface to Customer (MIC) which, in addition to measuring power usage, multiplies that usage by posted price and records total cost. Customers retain the freedom to select their consumption patterns. Homeostatic control is a new, untried concept. It is discussed in this paper because its great potential makes it a vehicle for interesting discussions of where the future may actually evolve.

INTRODUCTION

Rationale

Today's regulated electric utility system was built and is operated under a "supply follows demand" philosophy. The customer has the right to demand any amount of energy, and pays a constant, prespecified, infrequently updated, price. The philosophy of "supply follows demand" may be criticized for a variety of reasons:

- The need for rapid load following and large spinning reserve margins causes inefficient use of fuel;
- The large ratio between peak and average load implies that extra utility system capacity and distribution systems must exist to supply peak demand;
- The fixed nature of electricity prices discourages some forms of energy conservation and customer generation;
- The isolation of customers from the problems of the supply system makes it vulnerable to both short-term (New York City-type blackouts) and long-term (coal strike or oil embargo) emergencies;
- Finally, government regulation plays a mixed role; customers are isolated from changes in real cost while utilities are isolated from the effects of competition.

To be presented at the IEEE Power Engineering Society 1979 Summer Meeting, Vancouver, B.C., July 1979. Also accepted for publication in the IEEE Transactions on Power Apparatus and Systems. Submitted January 31, 1979.

This paper introduces a basic philosophy in which the supply (generation) and demand (load) respond to each other in a cooperative fashion and are in a state of continuous equilibrium. Homeostasis is a biological term referring to the "existence of a state of equilibrium...between the interdependent elements of an organism." It is appropriate to apply this concept to an electric power system in which the supply systems and demand systems work together to provide a natural state of continuous equilibrium to the benefit of both the utilities and their customers. A set of interrelated physical and economic forces maintains the balance between electric supply and customer load.

Energy costs, including costs for electric power, have risen sharply in the recent past and may be expected to continue to rise in the future. This increase in costs makes conservation of energy more important and makes it increasingly important that the allocation of energy costs fall precisely on the user of that energy.

Variation of load levels on electric utility systems impose real costs. For equity and economic efficiency, the price of electric energy should reflect the variation in costs brought about by fluctuations in system load. The price should, therefore, be relatively higher when system load is high, and relatively lower when system load is low. Time-of-day rates attempt to adjust price to load level, based on the fact that, historically, load has been higher at some times of the day and year than at others. Such rates cannot, however, account for actual operating conditions or for load as it may be affected by, for instance, weather variability.

A second approach to reductions of the costs of uneven demand has been the use of direct utility-consumer communications to implement a "load follows supply" concept. Under such a system, carried to the extreme, the customer's demand would be controlled through interruption of power to specific uses. This has the advantage that it would allow the utility to run at constant output. Capital could be used to the optimum extent, and the system's vulnerability to equipment failures, oil embargoes, coal strikes, and weather would be reduced to a minimum. Any contingency of supply would be matched by a reduction of load. While such a system might be efficient and produce electric power at minimum cost, it is unlikely that it would be politically or socially acceptable.

The concept of Homeostatic Utility Control utilizes the economic response to price on the part of suppliers and consumers combined with the revolutionary developments occurring in the fields of communication and computation to develop an efficient, internally-correcting control scheme. The basic communication systems for such a scheme are being designed or are undergoing testing today. These open new possibilities in the control and operation of electric power systems, which are further enhanced by advancement in computation hardware. Large-scale integration is making

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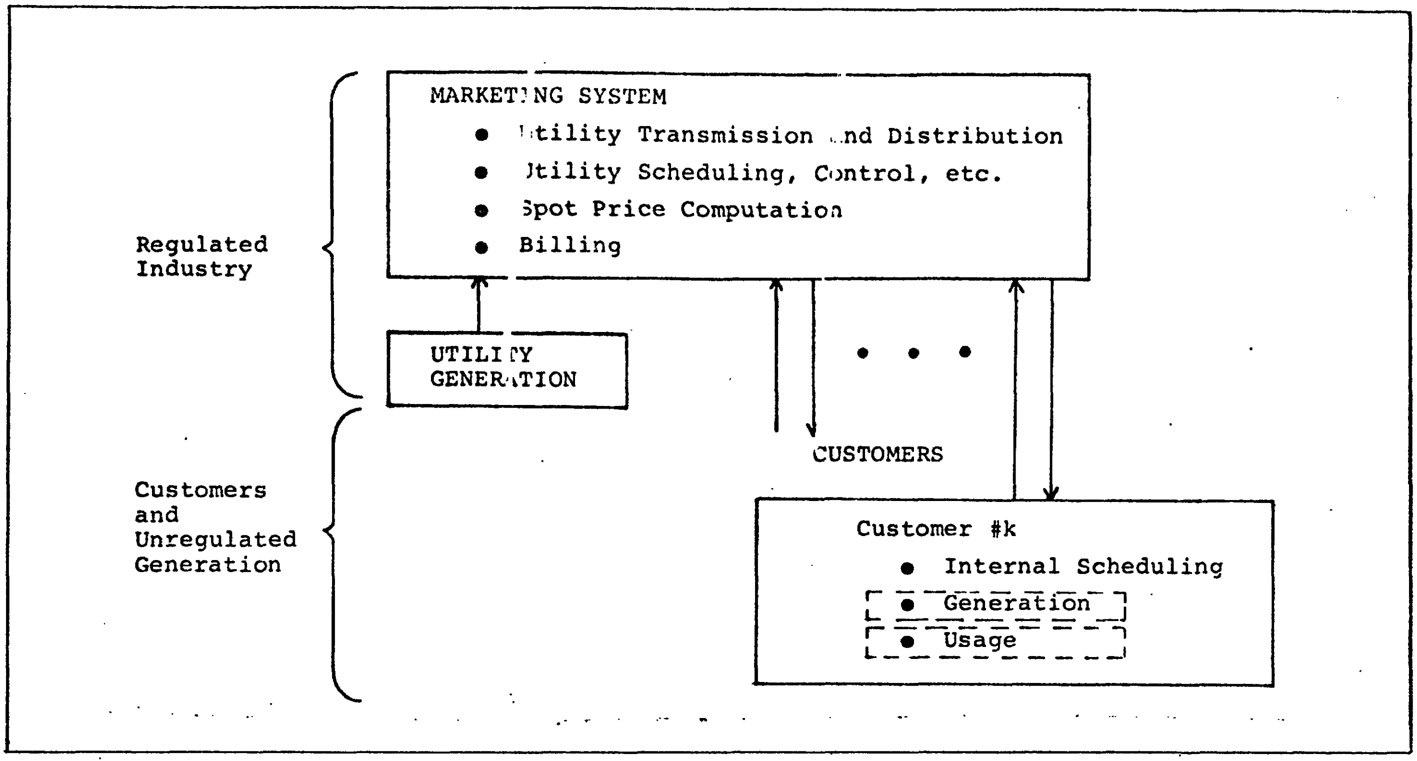

FIGURE 1: The Energy Marketplace

sophisticated computational ability available in small, economical packages. These developments will make it possible to communicate between customer and supplier and to control electric power systems in highly sophisticated ways.

The philosophy of Homeostatic Utility Control can offer a set of advantages of both "supply follows demand" and "demand follows supply" while avoiding the majority of their major pitfalls. It offers a continuous accommodation of the utility and customer to achieve stability and to minimize costs through a price-guided process involving independent choices by all parties.

Basic Structure

Homeostatic Utility Control requires three distinct functional developments or adaptations for its successful implementation. The first is a short-term mechanism which can operate to balance the supply and demand in a time frame less than five to ten minutes. Within current Utility Generation systems this function is generally fulfilled by governor and AGC action in central power plants which cause supply to follow demand. An alternative, lower-cost approach which causes demand to follow supply is based on a Frequency Adaptive Power Energy Rescheduler (FAPER). A FAPER is a frequency-responsive switching device which will control significant energy (as opposed to power) consuming loads. An example of such a load would be an electric melt pot in a processing plant or, at a residential scale, an electric heating or hot water system. The basic principle of the FAPER is rescheduling uses of electricity in which the demand is for an average rather than an instantaneous condition. The FAPER will turn the device off and back on as a function of the utility's ability to provide energy.

The second concept required for Homeostatic Utility Control is that of a mechanism by which consumers can pay a price for electricity which reflects, over time, the true current cost of the energy which they are receiving. This Energy Marketplace, in Figure 1, contains three classes of actors: first, the Customer who purchases power from the Marketplace or sells excess generation to it, second, the Utility Generation which is a supplier of electricity to the Marketplace, and, third, the utility Marketing System which acts as a broker for the electricity. The Marketing System is responsible for transmission and distribution and billing and metering transactions required both to distribute the electrical energy and to record the time and quantity of energy supplied and consumed; it is also a repository for information concerning the cost of generation and the willingness of the consumer to buy electricity at a given price. As will be discussed in greater detail in the sections which follow, the Marketplace operates under a set of "spot prices" for the energy which reflect both the capital and operating costs during any given period of time. The spot price becomes, therefore, the currency which both establishes the level of demand on the part of the sum of the customers and guarantees the supplier a fair return on the energy generated during the time period.

The third concept in Homeostatic Utility Control is the requirement for a device or set of devices which can provide the communication and recording functions critical to the operation of a system with high variability in the critical variables such as cost and price. The Marketing Interface to Customer (MIC) capable of maintaining and billing against variable spot prices as well as acting to credit a consumer with significant "storage" through FAPERs installed in his system. A MIC varies in complexity as a function of application and expected energy usage from large systems for industry to relatively simpler systems which could be installed in an individual residence.

It is important to conclude this general discussion of Homeostatic Utility Control with one negative caveat. The system has never been tried, and detailed analysis is just getting started. As of the time of writing, plans are to carry on beyond discussing concepts with utilities and with academic colleagues to the construction of FAPERs and MICs and to the completion of some detailed engineering and economic analyses.

THE FREQUENCY ADAPTIVE POWER ENERGY RESCHEDULER

A FAPER is activated by changes in the frequency of the electric powery system above and below the standard 60 Hz. The FAPER provides a new type of low-cost, short-term, lossless storage adaptable to the power system. FAPERs operate on loads which require energy rather than power.* FAPERs have no long-term impact upon the amount of energy used, but they do shift the actual period of consumption to times of relative availability on the part of the utility.

As an example consider the operation of an industrial melt pot with a FAPER. If the melt temperature lies outside of the maximum and minimum allowable range, the heating system is turned on and off accordingly, independent of frequency. However, if the temperature is within the allowable range, the heating system operation is influenced by the measured frequency. If the frequency is below 60 Hz, the heating system operation tends to be turned off; if frequency is above 60 Hz, the heating system tends to be turned on. When supply (mechanical power out of turbines) is less than demand (electric power to customers), system frequency decreases and vice versa. Thus, decreasing demand when frequency is low is a stabilizing action.

The power frequency response characteristic, discussed in detail by Appendix A, can be adjusted to perform different functions such as:

- Governor Function: Demand is responsive to small frequency changes associated with random load variations (less than one minute).
- Spinning Reserve Function: Demand is responsive to large frequency changes associated with loss of generation, tie lines, etc. (1 to 10 minutes)

A FAPER uses only locally available measurements, i.e. frequency and in the example of heating systems, temperature, so the basic FAPER concept does not intrinsically require any utility-consumer communication. However, such communication systems make it conceptually possible to adjust the power frequency response characteristics, $g[\Delta f(t)]$ and frequency reference, to changing system conditions. The advantages of this extra level of sophistication are unexplored at the present time.

FAPERs contain:

- frequency measurement;
- temperature or other process measurement;
- control logic;
- output actuation, and
- power supply.

Consider a customer (industrial, commercial or residential) with various, independent energy usage-type devices to be placed under FAPER control. Three possible approaches are:

- Stand Alone: Each FAPER is located at an individual device with its own sensors, logics, actuators, and power supply;
- Common Supply: One power supply and frequency meter serve all the individual logics located at the devices;
- Common Logic: One computer makes the decisions for all the devices at a site.

The capital cost per device is dependent on which approach is used. Installation costs for retrofitting FAPERs on existing devices would probably be prohibitive, except for large devices, such as those found in industry, and possibly electric home heating. However, FAPER installation costs on new devices should be minimal after the technology is established.

Installation of FAPERs can be viewed as giving the power system short-term energy storage which can be used to provide "governor action" and "spinning reserve." This energy storage can be assumed to be lossless compared, for example, to pumped hydro. Its speed of response is determined by the FAPER's electronics. The only costs are those of building and installing the FAPERs.

A rough feel for some of the factors involved can be obtained as follows:

Define:

x: Capacity of device under FAPER control, i.e., power used when device is on (kW).

T: Length of time device is on during normal cycle.

Then

xT: Maximum stored energy (kWh).

On the average, only some percentage of this "stored energy" can be considered to be available at any instant for control because of the device's normal cycle and the probability the device itself is in a turned-off mode (e.g., home heating in the summer).

Define:

p: Probability device is in active mode (e.g., it is winter for a home heating device) $0 \leq p \leq 1$

Then, taking into account the randonmess of the cycling, a crude approximation yields

$\frac{xTp}{2}$: Amount of stored energy available for control on the average at any instant of time (kWh) (1)

Define:

c: Capital, installation cost of FAPER ($)

Then

$K = \frac{2c}{xTp}$: capital cost of controllable storage (kWh) (2)

Many possible sets of reasonable guesses for numerical values are available depending on the device. For electric home heating, one set of numbers is:

x = 50 kW
T = 0.2 hour (12 minutes)
p = 0.25 (3-month heating season)
c = $10

which yields

K = $8/kWh.

If enough FAPERs were in operation, it would be possible (conceptually at least) to remove the existing central power station governors and the central dispatch AGC system. A slower (5-minute) central-dispatch control signal would be sent to the power plants based on economics and the need to remove time and energy errors. With such a system, tie-line interchange would be maintained and balanced on a longer time scale based on estimated/computed flows as well as direct measurements. This "smoothing out" of the central power station behavior has economic value in terms of improved heat rates and less "wear and tear" on the plants.

The value of a FAPER's ability to provide spinning reserve can be determined by evaluating the costs of conventional spinning reserve for the utility of concern.

FAPERs provide a distributed type of control action. Intuitively, it is better to control a large, complex, distributed system using many small, distributed control actions on them than to apply large control forces at a few points (like power plants). Thus, FAPERs have the potential of improving the overall power system's dynamic characteristics and hence influencing the transient stability, dynamic stability, and long-term (slow-speed) dynamic control problems.

ENERGY MARKETPLACE

While the primary purpose of the FAPER is to smooth out short-term supply-demand inequalities, the Energy Marketplace concept strives to improve the economic operation of the system. The key to the Energy Maketplace approach is the setting of electric energy "spot prices," which vary as frequently as every five minutes, depending on overall system demand, plant outages, solar generation, wind generation, fuel costs, and other factors.* They can also

*It is possible to define "energy-type usage devices" as being characterized by (1) a need for a certain amount of energy over a period of time in order to fulfill their functions and (2) indifference as to the exact time at which the energy is furnished. Examples include space conditioning, water heating, refrigeration, pumping, ovens, melting, and grinding. Similar "power-type usage devices" are characterized by needing power at a specific time. Examples include lights, computers, TV, and many motors used in industrial processes.

*The terms "Energy Marketplace" and "spot price are taken from reference [1].

change with respect to geographic location in the service area because of differences in spatial conditions such as T&D losses, line loading, and localized weather patterns. The spot prices provide an economic stabilizing mechanism that tends to keep the overall supply-demand system in equilibrium: as consumption goes up, so does price, which tends to reduce consumption while increasing production. This smooths out the unanticipated demand variations over time.

The spot price for a customer to buy power from the system would ordinarily be different from the spot price paid by the system buying back power from a customer. The difference in the buying and buying-back spot prices reflect transmission capital costs and losses and billing and metering costs. Allocation of utility generation capital costs presents difficulties. To facilitate a discussion of the issues and potential approaches for updating the spot prices, this presentation decomposes the utility system into three component "actors," as was first shown in Figure 1:

- The Utility Marketing System which is the part of the electric utility responsible for the transmission and distribution of power, control of Utility Generation, computation and communication of the spot prices to the consumers, and billing.
- The Utility Generation, which supplies power to the Marketing System from the individual utility-owned generation and storage plants to the Marketing System.
- The Customers, who can individually buy power from the Maketing System or sell excess self-generated power to it. Each customer is responsible for the scheduling of his own usage and generation at the set spot prices; this can be accomplished through any means ranging from intuition to the employment of a computer-based scheduler that takes account of current and anticipated spot prices.

The separation of the utility into separate Utility Generation and Marketing System components is made solely as a vehicle for the exposition of the Energy Marketplace concept.

The establishment of an Energy Marketplace and the selection of a procedure for calculating the spot prices is a significant change from the current process where every price modification must be approved by the regulatory process. It is a generalization of the approach taken for fuel adjustment clauses: the adjustments are not a subject to review, but the procedure for calculating them is reviewed.

The two important issues in the determination of a procedure for setting the spot prices are, first, the allocation of costs and profits among the actors and, second, how the customers can react to the pricing system by modifying their usage and generation patterns. The following subsection discusses potential approaches for selecting the spot-pricing formulae. The second subsection describes methods for the consumer to react to the spot-pricing information.

Spot-Pricing Formulae

There are many possible approaches to the setting of spot prices. At one extreme, prices could be set so that load and generation just balance without regard to the profits or losses received by any party. At the other extreme, the utility and the customers alike could be monitored and controlled so that no party receives what would be considered an unfair return. Politically and economically acceptable approaches, however, must mix these two extremes — with necessarily more complicated pricing procedures.

The selected formulae for determining spot prices must reflect the typical range of often conflicting goals involved with utility pricing and system dispatching. The specification of the goals themselves can be as controversial as the personal philosophies of "social good" or "fairness." Several potential goals that have arisen in discussions are:

- The Marketing System should minimize operating costs.
- To prevent monopolistic pricing and guarantee a fair rate of return on capital, regulation may be necessary.
- The present and future reliability and availability of power should be ensured.
- Demand levels and patterns should be influenced to take on desirable characteristics.

Appendix B elaborates on these points and outlines some of the spot-pricing formulae that could be implemented.

In practice, it is expected that no single set of spot-pricing formulae will be universally agreed upon as being best. Fortunately, the Homeostatic Utility Control concept is such that the choice of spot-pricing formulae can be adapted to fit the particular needs and philosophy of the area being served by the utility.

Utility and Customer Scheduling of Generation and Usage

The utility and the customers independently determine their patterns for generation and usage of electricity subject to the spot prices. Spot prices are not predetermined since they depend on random events such as demand fluctuations, weather conditions, plant outages, and numerous other factors. Usually it will be possible, however, to predict future spot prices with sufficient accuracy so that both the customers and the utility are able to schedule their generation and usage in an orderly fashion.

The Marketing System, the branch of the utility responsible for systems management, uses sophisticated, general-purpose, digital computers with extensive operator interaction for economic dispatch, unit commitment, maintenance scheduling, and fuel management for the Utility Generation. The Marketing System also forecasts customer purchases and sales since these affect the control of the Utility Generation; this modeling is done probabilistically because the customers are independently selecting their strategies according to their anticipations concerning future spot prices.

Customers are completely free to choose independently how and when they intend to buy, use, generate, or sell power. Each customer scheduler has available the current values of the spot prices as communicated from the Marketing System. A customer scheduler could also have models of the customer's needs for power, both real and perceived, as well as forecasts of future spot prices and weather.

The simplest type of customer scheduler would exist at the small commercial establishment or residential level. These would be simply spot-price readouts with the actual scheduling being done by human judgment. Usually such human decision making would ignore five-minute variations in spot price. However, a warning device could alert customers to unexpected events that have occurred or when spot prices have risen above some prespecified level.

The next level of complexity of customer schedulers are "special-purpose energy computers." These are small, essentially preprogrammed microor minicomputers, which accept a certain class of inputs specifying the customer's choice of life-style and priorities. The computer reschedules, as appropriate, various devices and provides the customer with various types of information and suggestions.

The most sophisticated customer scheduler is the general-purpose computer which is programmed specifically for the explicit needs of the customer. They would be installed in many of the larger commercial installations and almost all industrial installations. They would allow extensive automatic control features as well as sophisticated input-output devices for human interaction.

Usually spot prices will be quite predictable; however, fluctuations and uncertainties in price may be unacceptable to some customers. Such customers could obtain long-term contracts from the Marketing System in which the rate is prespecified; for example, they could be set for one year in advance, as in today's rates. These long-term contracts would include prespecified time-of-day or seasonal variations. Such long-term contracts with prespecified rates are viewed as "insurance policies," and the customer would expect to pay more on the average for the insurance associated with a long-term contract. These long-term contracts would have limits on the amount of energy and demand covered by the insurance. These are similar to the options and futures contracts offered in commodity markets — except they would probably be bundled in monthly or annual packages.

THE MARKETPLACE INTERFACE TO THE CUSTOMER (MIC)

A critical hardware element required to complete the Homeostatic Utility Control is the subsystem which is situated at the interface between the Marketing System and the Customer. The MIC serves several purposes. It is a usage-recording monitor, replacing the watthour meter. It also serves as an information transfer point, passing the posted spot price on to the customer, while relaying usage back to the Marketing System. The MIC may serve other functions, such as detecting changes in system frequency and passing information on differential frequency to the customer. It also detects responsiveness of load to changes in frequency.

The MIC is at the end of the Marketing System's information path, and represents the point beyond which the utility has neither direct control nor access to information.

In the simplest manifestation the MIC would have two functions. One would be to relay the spot price to the customer. The other would be to integrate cost, the product of price received from the Marketing System, and load, measured by a part of the MIC. Then the result would be:

$$b(t_1) = \int_0^{t_1} r(t)\, x(t)\, dt \qquad (3)$$

where $b(t_1)$ is the cost to the customer incurred over the time interval $0 \leq t \leq t_1$; $r(t)$ is the spot price at time t; and $x(t)$ is the load at time t.

The spot price $r(t)$ will have one of two values. If load $x(t)$ is positive, $r(t)$ will be the customer's buying price. On the other hand, if $x(t)$ is negative, the customer is generating power and $r(t)$ will be the system's buying-back price.

Communication once every five minutes from the Marketing System to every MIC is necessary to post the spot price. There seems to be little problem in establishing such communication with any of a variety of systems presently available or under test. However, security of communication and metering are areas of concern. Issues such as the possibility of communications error or tampering suggest the desirability of having a reverse communication capability from the MIC to the Marketing System to, for example, confirm the posted spot price.

FAPERs are designed so as not to interfere with the prime functions of the energy-type usage devices they control. However, customers still need some reason to install them, since they will cost something. It is possible that the utility could pay for them or their installation could be mandated by law. It is doubtful that such coercive methods would be very effective, however. A more appealing concept would be to reward frequency-dependent load behavior so that customers with FAPERs automatically get a financial benefit.

One way to provide a benefit to FAPER installations is to change the cost algorithm to:

$$b(t_1) = \int_0^{t_1} \left[r(t) + h[\Delta f(t)] \right] x(t)\, dt \qquad (4)$$

where $h[\Delta f(t)]$ is a price differential that is a decreasing function of frequency, roughly of the form shown in Figure 2. The $\Delta f(t)$ is the frequency deviation from nominal. On the long-term average, this logic would yield financial benefits for customers with FAPERs.

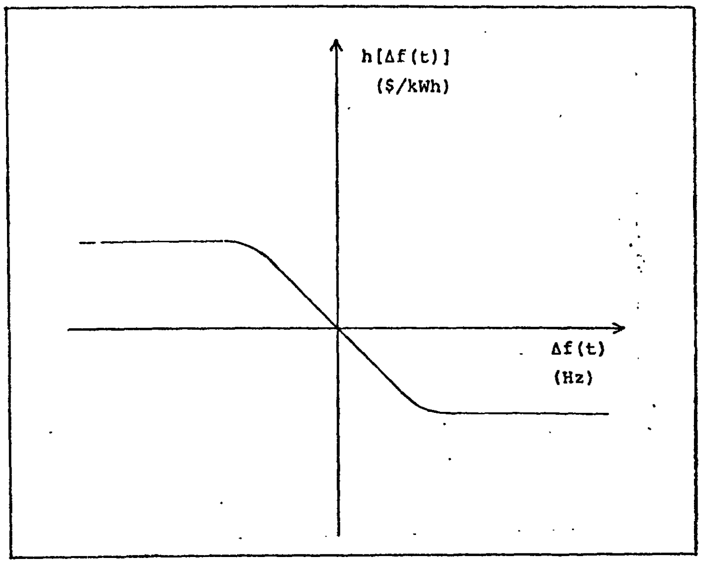

FIGURE 2: FAPER Price Differential

A potential disadvantage of this approach is that customers receive financial benefits from FAPERs only when the FAPERs actually affect demand. FAPERs can provide a spinning-reserve function even when it is not used. Therefore, an alternative approach is to have MIC estimate what portion of a customer's demand is under FAPER control, on the average. This would be done by observing load changes coincident with frequency changes. This percentage would be used as the basis for a billing credit.

Further discussion of the MIC subsystem and associated customer subsystems is the topic of a companion paper [2].

CONCLUSION AND DIRECTIONS FOR FUTURE RESEARCH

Homeostatic Utility Control is a concept which looks forward to the utility systems at the turn of the coming century. The basic premise is that technological and economic conditions will change over the next 20 years to create a system whose control mechanisms will need to be fundamentally different from those of today's utilities. These differences will come from the revolution in solid-state control devices which will provide the availability of metering systems that can interface the customer with the utility. Such systems will permit the utility to charge a rate for electric power which equals, or more nearly equals, the current costs of generating the power. At the same time it will be possible for customer generation to be introduced smoothly into the full utility system and paid for accordingly.

This paper has introduced three concepts which will be required for the utility control systems of the decades ahead. Each concept has been matched with a device or a scheme of implementation: a Frequency Adaptive Power Energy Rescheduler, an Energy Marketplace, and a Marketplace Interface to the Customer. These devices and control schemes are not the only approaches available but are intended to initiate the discussion. Given the limited research work which has been completed to date, Homeostatic Utility Control shows potential to:

- Generate a healthier climate in the relationship between the utilities and customers as customers see and appreciate the time-varying cost of electric power.
- Reduce the capital requirements needed for generation and transmission expansion by reducing the time variation in load.
- Reduce the need to carry certain types of spinning reserve which results in fuel and capital savings.
- Reduce the small, rapid governor actions of the large, central-station generators, resulting in fuel savings as well as less equipment wear and tear.

- Allow the system to accept more readily a stochastically fluctuating energy source, such as wind or solar generation.
- Simplify the expansion of cogeneration.
- Improve the dynamic behavior of the power system.
- Allow customers to retain complete independence of choice in pattern of demand as they respond only to price.
- Simplify control, operation, and planning of electric power systems because the Energy Marketplace and FAPERs introduce stabilizing forces which tend to keep the overall system in a natural equilibrium.

The above list represents the authors' efforts to stimulate discussion of what "might be" in terms of the development and control of electric utilities at the turn of the century. This list is not necessarily all-inclusive nor can its elements be substantiated at present. What lies ahead is the detailed developmental and analytic work required to prove both the physical and economic concepts. The purpose in preparing this paper has been to introduce a new set of concepts to the field and to bring to the fore the notion that utility control and operating procedures of the next century may look very little like those of today. Fundamentally different control mechanisms, whose constituent parts are in today's technology, will be required.

ACKNOWLEDGMENT

The ideas in this paper came from diverse sources. Their integration into the overall Homeostatic Utility Control concept started to take place in the Fall of 1978 during an internal workshop/seminar/discussion group of MIT faculty, staff, and students whose purpose was to take a "fresh look" at the future of power system control, operation, and planning. The authors of this paper wholeheartedly acknowledge the help and support of the many others who participated in the earlier discussions.

APPENDIX A

FAPER CONTROL LOGIC

The following FAPER control logic appears to have many advantages, but analysis of its overall system effect has not yet been carried out. Other types of specific logics are also under consideration.

In order to make the discussion explicit, the case of an industrial melting pot is used as an example.

Define:

t: time

$T(t)$: melting pot temperature

T_{min}: minimum allowable temperature

T_0: nominal set point temperature

T_{max}: maximum allowable temperature

$\Delta f(t) = (f(t) - 60)$: frequency deviation from 60 Hz

$u(t)$: $\begin{cases} 1 & \text{heater on} \\ 0 & \text{heater off} \end{cases}$

$t+$: time t plus a small increment

The present thermostat control logic is:

$$u(t+) = \begin{cases} u(t) & T_{min} < T(t) < T_{max} \\ 1 & T(t) \le T_{min} \\ 0 & T(t) \ge T_{max} \end{cases} \quad \text{(A.1)}$$

The FAPER Control Logic involves changing this equation to:

$$u(t+) = \begin{cases} u(t) & T_\ell < T(t) < T_u \\ 1 & T(t) \le T_\ell \\ 0 & T(t) \ge T_u \end{cases} \quad \text{(A.2)}$$

where

	$\Delta f(t) < 0$	$\Delta f(t) > 0$
$T_u(t)$	$T_{max} + g[\Delta f(t)]$	T_{max}
$T_\ell(t)$	T_{min}	$T_{min} + g[\Delta f(t)]$

and $g[\Delta f(t)]$ has roughly the shape of Figure A.1.

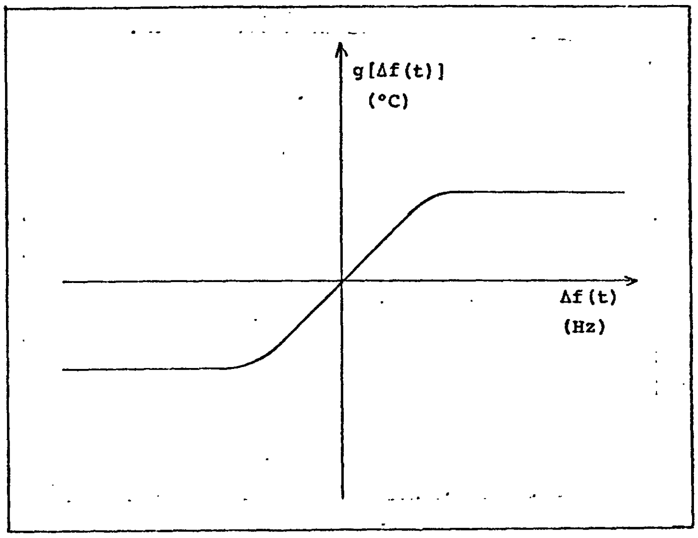

FIGURE A.1: FAPER Power Frequency Response Characteristic

APPENDIX B

SPOT PRICING METHODS

In the development of this paper, the most heatedly discussed aspects have been alternative schemes for the setting of spot prices. This appendix summarizes some of the issues and outlines various types of spot-pricing formulae. No single formula or philosophy is being advocated here since Homeostatic Utility Control is not tied to any particular spot-pricing method.

Define:

$e(t)$: time rate of expenditure ($/hour)

$r(t)$: current spot price for electric energy ($/kWh)

$x(t)$: power flow at time t (kW)

$g(t)$: generating capacity (kW)

where the following subscripts and superscripts may be used to identify specific applications of the above variables.

Subscripts:

k: customer identifier (k = 1, ...)

n: utility generator identifier (n = 1, ...)

f: fuel component

op: operation component

m: maintenance component

cap: capital component

cb: customer buying from Marketing System

bb: Marketing System buying-back from customer

Superscripts:

ug: utility generation

ms: marketing system

hence, for example,

$r_{cb,k}(t)$ = selling price paid by kth customer to buy from the utility

$r_{bb,k}(t)$ = buy-back price paid to kth customer for selling to the utility

$x_{cb}(t)$ = summed net power flow to all customers

$e_f^{ug}(t)$ = cost of fuel being consumed by the Utility Generation

$x^{ug}(t)$ = total utility generation

Pricing Philosophy

The basic concept of spot pricing is to establish a reasonable customer buying price ($r_{cb,k}(t)$ \$/kWh) that reflects the time-varying cost of energy production and delivery to that customer's terminals. A customer buy-back price, $r_{bb,k}(t)$, must also be established for reverse energy flow. It may be derived from the above or computed independently.In either case, $r_{bb,k}(t)$ must be less than $r_{cb,k}(t)$.

One clear issue is that customers should not contribute to the costs of the supply system "downstream" of their specific location. Capital and loss costs of the distribution network will be shared among the customers supplied by that specific part of the system. This would enable decisions on future changes to a local section of the distribution to be made, at least in part, by the affected customers--who would clearly carry the costs.

Philosophical questions in establishing the customer buying price $r_{cb,k}$ include:

- Should the price be computed on the basis of historical costs, on the basis of expected future expansion costs, or should it contain elements of both?
- Should operating costs at a given point in time be based on average costs, incremental costs, or a mixture of both?
- Should capital costs be based on total system capacity, on the average capital cost of units presently connected, or on the capital cost of the last unit connected?
- What value should be assigned to voltage quality, reliability, and availability of supply?

The customer buying price will normally be dominated by fuel and capital costs and many methods have been suggested for the calculation of these cost components, some of which may have far-reaching consequences for system planning and operation.

For example, peaking units, such as gas turbines, will appear much more expensive if capital costs are recovered only during their actual hours of operation rather than over the physically useful lifetime of the unit. This cost difference would be reflected in a significant difference in the rate of rise of the spot price near the generation capacity limit; generation expansion policy would probably also be affected.

Similarly, capital charges would tend to be much higher if based on future replacement costs rather than on historical construction costs.

Specific Examples: $r_{cb}(t)$

Some specifc example of price calculation for the customer buying spot price $r_{cb}(t)$ follow. Distribution system costs are neglected for simplicity because of their variation with customer location and voltage level.

1. "Average cost"

$$r_{cb}(t) = [e^{ms}_{op,f,m}(t) + e^{ug}_{cap}(t)]/x_{cb}(t) \tag{B.1}$$

where

$x_{cb}(t)$ is the power flow to customers,

$e^{ms}_{op,f,m}(t)$ is the total marketing system operating expenditure,

given by

$$e^{ms}_{op,f,m}(t) = e^{ug}_{op}(t) + e^{ug}_{f}(t) + e^{ug}_{m}(t) + \\ + e^{ms}_{op}(t) + r_{bb}x_{bb}(t) \tag{B.2}$$

and

$e^{ug}_{cap}(t)$ is the capital expenditure.

The capital term, $e^{ug}_{cap}(t)$, can be derived from either total plant capital or only that for the units connected. It may be calculated on either

- a historical basis,
- estimated future replacement cost, or
- some combination of these.

2. "Incremental Cost"

In this case the expenditure is computed as for case 1, but $r_{cb}(t)$ is taken as the local gradient at the given operating point:

$$r_{cb}(t) = \partial[e^{ms}_{op,f,m}(t) + e^{ug}_{cap}(t)]/\partial x_{cb}(t) \tag{B.3}$$

3. "Average Cost Plus Quality of Supply"

In this scheme $r_{cb}(t)$ has the components: (i) an economic cost component derived as in case 1, (ii) a "short-term quality of supply" component based on the probability of loss of supply at the present operating point. This component is designed to signal the customer of the changing quality of supply owing to problems such as line overload or stability limits, in order that those who can provide equivalent quality supply more cheaply by internal means will do so. There would normally be local as well as system-wide contributions to this price component. Revenue obtained from this price component could be directed towards rectifying the course of the quality degradation. (iii) A "long-term quality of supply" component based on system expansion needs, computed by long-term expansion studies based on predicted system growth. This component would be spread evenly over all energy sold, and adjusted only on a yearly basis. It is designed to forewarn customers of the most likely long-term future trend in pice. Revenue could be allocated to forward financing of new major plant.

4. "Marginal Cost"

This approach differs from the other three in that it is based entirely on the incremental change in future predicted costs produced by a step change in power flow at the present time. It would be computed by means of long-term system expansion studies.

Specific Examples: $r_{bb}(t)$

Some specific examples of the customer spot buy-back price, $r_{bb}(t)$, follow. The customer buy-back price may be derived from $r_{cb}(t)$, derived by an independent method, or left to float according to demand. There would normally be the constraint $r_{cb} \geq r_{bb}$.

1. "System Lambda"

The value of r_{bb} would be set equal to the incremental fuel cost of the most expensive utility generation. This would tend to minimize overall fuel costs. If utility generation was already at full available capacity, both r_{bb} and r_{cb} would rise to the natural supply/demand level. In the notation of this appendix

$$r_{bb} = \frac{\partial [e_f^{ug}(t)]}{\partial x^{ug}(t)} = \lambda^{ug} \tag{B.4}$$

2. "System Lambda Plus Quality Constraint"

A quality constraint is added to the incremental cost of case 1. This would tend to give forewarning of operating problems and give a transition between "normal" and "emergency" conditions.

3. "Free Market"

This is the ideal free market case where price is always allowed to find its own level from supply/demand forces. In this case r_{bb} and r_{cb} move together with an allowance for marketing system operation.

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Chapter 2: POWER SYSTEMS ECONOMICS AND PRICING

2.1 Introduction

Communications and metering technologies have limited our ability to reflect short term changes in utility operating costs in the price of electricity sold to the customer. Recent advances in both communications and in metering technologies brought about by the availability of microprocessing equipment and by dramatically rising energy costs has focused increased attention on pricing methodologies which produce more efficient consumer responses. The short paper which follows presents a concept of "spot prices" in which it will be possible for the consumer to receive information on pricing as frequently as every five minutes. Such systems are being considered initially, for larger users such as industsries and large commercial establishments rather than for residential customers. The spot pricing structure is largely blind to the pricing methodology chosen and as a result is equally applicable to average costing structures as it is to marginal costing structures. In addition, implementation of a spot price system does not in any way preclude other customers from existing on long term energy contracts, or any other structure analogous to today's rate schedules.

A set of issues have been identified which effect the economics and pricing of electric power systems, which could be more efficiently handled using Homeostatic Control. Basic to these issues are questions of the methods by which prices are set, and the regulatory process by which price information passes between the utility and the customer. The paper which follows does not discuss the issues associated with the methods of pricing available to utilities; specifically it does not focus on questions of marginal versus average costing, and of embedded versus replacement costing. These issues are amply covered in the literature on utility rate setting. (See, for instance, Kahn (1970)). It is significant at the beginning of this discussion to identify a critical issue to utility economics and regulation which is central to the concept of Homeostatic Control systems; the establishment of formulae for pricing as opposed to the setting of price schudules.

Current practice in utility pricing allows the utility to establish before the regulatory commission a schedule of charges to be applied over some period of time to a given customer class. This schedule is fixed in time and by class regardless of any changes in patterns of consumption and with limited flexibility in passing on changes in costs of generation, both of which may occur during the time period between rate hearings. Advanced systems of rate schedule setting, discussed in greater detail later in this paper, include the use of time-varying rates which reflect a hybrid of schedules and formulae, essentially using specific formulae to establish variable rates imposed during time intervals which can be established to be as short as five minutes. The acceptance and implementation of systems such as Homeostatic Control require that there be an acceptance of formulae to be used in setting rates.

While, as we shall discuss below, there are clear economic advantages to completely flexible, time-varying rates, the acceptance of the use of a PUC agreed-upon formula will depend on the amount of uncertainty that consumers of all classes will face in predicting a price or any given future time interval.

2.2 Rate Calculation

Within the area of rate setting one of the major concerns of electric utility analysts is that of assuring that each additional unit of demand is faced with an appropriate price for that demand. One issue over which debate takes place deals with the question of whether rates should be set according to embedded costs (also called 'historic' or 'accounting' costs) or whether prices should reflect the costs of adding one more unit of capacity and producing more energy.

The historic approach is that most often used by regulators and is justified as allowing electricity-generating monopolies to recover their sunk capital and their operating costs plus a reasonable rate of return on expenditures actually made on their capital equipment. While embedded cost rate-setting has been shown, in Joskow and MacAvoy (1975), to result in financial stringencies for utilities that are faced with increasing loads, the same paper suggests that these capital shortages can be overcome by allowing a sufficiently high rate of return, fourteen percent being suggested as an adequate rate.

The replacement or marginal approach, favored by economists, requires that consumers pay for electricity the costs of the resources actually required to meet additions to their demand (or, conversely, benefit by the value of resources not required due to conservation efforts). While embedded-cost pricing of electricity will cover the costs of holding the utility's current stock of capital, marginal-cost pricing implies that the utility charges a price for the capital component of electricity that is equal to the cost of recently completed or imminent projects. Total revenues under the latter scheme will thus appear to reflect the costs of replacing all the utility's generating units at those units' current (or 'replacement') costs. The marginal concept leads to the conclusion that at any given level of demand, the price of electricity should reflect the replacement capital cost plus the fuel costs of electricity from only the generating unit 'switched on' to meet that demand.[1]

An improvement that can be made to any fixed pricing schedule (either embedded or marginal) that imposes one price for electricity demanded in all periods, is that of time-of-day (TOD) pricing. Under this scheme, prices in any given time period correspond, roughly, the expected costs of maintaining the supply of electricity necessary to meet expected demand in that time period. The chief problem with any fixed schedule of TOD prices is to know how wide each time bracket should be. A regulatory body wishes to avoid making the peak time brackets so wide as to impose peaking prices on demands that can be met entirely with base-load plants, but not so narrow that any shifts in peaks will result in peak demands facing base-load prices.

The advantages of Homeostatic Control is that, whatever the pricing formula adopted, a new price can be calculated and set for any time

[1]We will not be addressing, here, the problem of redistributing the surplus revenue that may result from replacement-cost pricing. Many schemes are available that would meet criteria of economic efficiency (so that rebates do not effect purchasing decisions) and equity (for instance, to soften the impact on high electricity costs on low-income customers).

period, down to at least five minute intervals. The price will be set using information on the fixed and variable costs of producing electricity to meet the level of demand encountered by the utility during the previous time interval. These prices will be set automatically utilizing agreed upon formulae and, therefore, without the intervention of the regulatory body.

In addition to benefits gained by eliminating rigid TOD-pricing periods, this system removes the need for periodic reviews of rates and thus some of the non-optimal responses (from an economic point of view) that utilities will make in attempting to profit-maximize (as opposed to cost-minimize) under regulatory constraints with only periodic reviews and with delays between rounds of 'test year' calculations and uncertainties as to the timing of the next review. There is already a wealth of literature on these problems, just one segment of that literature discussing the existence (or attempting to measure the magnitude) of the Averch-Johnson effect[2] by which utilities favor capital investment over other inputs not included in their rate base. Other writers, including Bailey (1970) and Baumol and Klevorik (1970), suggest that regulatory lags and fixed prices will stimulate cost-saving research and innovation. Klevorik (1973), using a still more comprehensive model points out that such conclusions are too strong and, possibly, false. Nevertheless there seems little doubt that regulatory lags do lead to non-optimal supply decisions. A clearer case of the biases that regulatory lags impose on input decisions arises when these

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2 The original reference is Averch and Johnson (1962). The literature on the A-J effect is reviewed in Joskow and Noll (1978).

lags are combined with prices that are allowed to rise only with increases in the cost of one input, usually fossil fuels. Such an effect is posited, in Atkinson and Halvorson (1976), to offset the Averch-Johnson effect.

In summary, then, we find that Homeostatic pricing will have two distinct economic benefits; first, the removal of rigid time-of-day pricing periods on a randomly fluctuating demand and, second, the removal of intra-period incentives for the utility to make inefficient production decisions. When combined with a marginal-cost pricing formula, utilities with some portion of their supply under Homeostatic pricing will find themselves facing less pronounced peaks in demand. In addition the utility may be offered large blocks of power during peak periods, as cogenerators, for instance, find that their costs of producing electricity are equal to or lower than the utility's additional costs in generating that power.

Customer willingness to accept formulae rather than strict schedules, industrial willingness to augment cogeneration potential for sales to the utility and utilities' willingness to offer firm contracts for electricity purchases from customers will depend, as we have said, on

i) the stability of prices from one period to the next, which we call 'inter-period consistency' and

ii) the predictability of prices at some time interval of some future day, given information on the price during the same interval of some previous day. This point will depend on whether information about recent loads, about meteorlogical data and about maintenance schedules will allow accurate predictions of prices to be made and thus reduce uncertainty in investment, operating and housekeeping decisions of both customers and utilities.

Examining the inter-period consistency and predictability of pricing formulae is the main point of this paper. In order to undertake this exercise we have created a simple model of utility customer interaction. A description of the utility being modeled and of the model itself, is found in the next section. In the subsequent section we present some hour-by-hour results generated by various pricing formulae from our model and draw conclusions as to the variability of prices. Finally we discuss a broader range of issues and behaviour patterns than can be captured in our modeling effort.

2.3 Utility Scenario

In order to examine the behavior of prices under Homeostatic formula-based pricing, a simple model of a synthetic utility has been developed. The utility modeled is based upon an EPRI-developed synthetic utility for the northeast but contains no hydroelectric capacity and no pumped storage. The generation capacity is divided into 1200 MW of nuclear, 200 MW of coal, 3600 MW of oil and 500 MW of gas turbines. Heat rates for the plants are assumed flat over their operating ranges and have been developed from information provided by a set of New England Utilities and thus represent reasonable regional averages. The load data for the analysis has been provided by Boston Edison and scaled down to give a peak demand of 5042 MW, which occurs in August. Financial information is based on information provided by New England Electric (NEES). Average costs for operating, fuel and transmission and distribution are also those estimated by NEES, the latter being added as a fixed amount to the cost of each kWh generated. More detailed assumptions about the synthetic utility are to be found in Table 2.1.

The utility thus developed represents an oil-based system with a high proportion of nuclear. It's peaking requirements are provided by gas turbines which are required infrequently through-out the year. We shall see below that, as one would expect in a system with a large amount of base and intermediate power being generated arising from oil-burning units, the prices calculated do display a stability and inter-period consistency over a broad range of demand. Prices do vary upward as one nears the system peak in the summer and winter months.

The analytical model developed is a short-term production-costing model which has been simplified for our purposes to look at only three weeks per year for each of seven rate formulae which we examine. The weeks chosen were one off-peak in the spring, one week in August, which represented the summer peak, and one week in December which represented the winter peak. The base analysis did not include any allowance for either maintenance or for forced outages given the time periods analyzed. As will be seen, a sensitivity run was carried out in which a major base load plant was removed from the sytem. During the spring period this removal represents a planned maintenance while during the summer and winter this would more nearly characterize a forced outage.

2.4 Pricing Formulae

We have used six of many possible pricing formulae for the purpose of this presentation. We will describe each in detail, though descriptions of the calculations will be provided in a subsequent section.

Case 1: The first case defines capital cost to be the average cost of capital for all electricity generated over a one year period, computed

TABLE 2.1

ASSUMPTIONS AND DATA SOURCES FOR
HOMEOSTATIC UTILITY SIMULATION

	NUCLEAR	COAL	OIL 1	OIL 2	OIL 3	GAS TURB
FUEL COSTS ($/MBTU)	0.40	1.69	2.90	2.90	2.90	3.70
HEAT RATES (MBTU/MWH)	10.4	9.5	9.3	9.4	9.9	14.0
CONSTRUCTION DATES	1975	1962	1961	1967	1973	1970
ANNUAL COST CARRYING FACTORS EMBEDDED/ REPLACEMENT	.1460/ .1610	.1545/ .1695	.1545/ .1695	.1545/ .1695	.1545/ .1695	.1543/ .1693
CAPACITY FACTOR	.7765	.8550	.7900	.7083	.3349	.0436

on the utility's embedded rate base. The fuel and operating cost (hereinafter referred to merely as the fuel cost) is the averge fuel cost for all electricity generated during the relevent time interval. We refer to this as the allocated fuel cost. The price charged is the sum of these two costs.

Case 2: The fuel cost in this case is the allocted fuel cost as described in Case 1 and the capital cost is again based on the historic costs of each unit. However, capital costs are based on the actual amounts of electricity produced from each unit. The capital cost during any time interval is, then, the average of these capital costs, per kWh, of all electricity produced to meet an interval's demand, which we refer to as the allocated embedded capital cost. The price set is the sum of the allocated fuel cost and the allocated embedded capital cost.

Case 3: The capital cost considered here is, again, the flat, average embedded capacity cost used in Case 1, while the fuel cost is the fuel and operating cost of the marginal plant used to meet the interval's demand. The price is the sum of these costs.

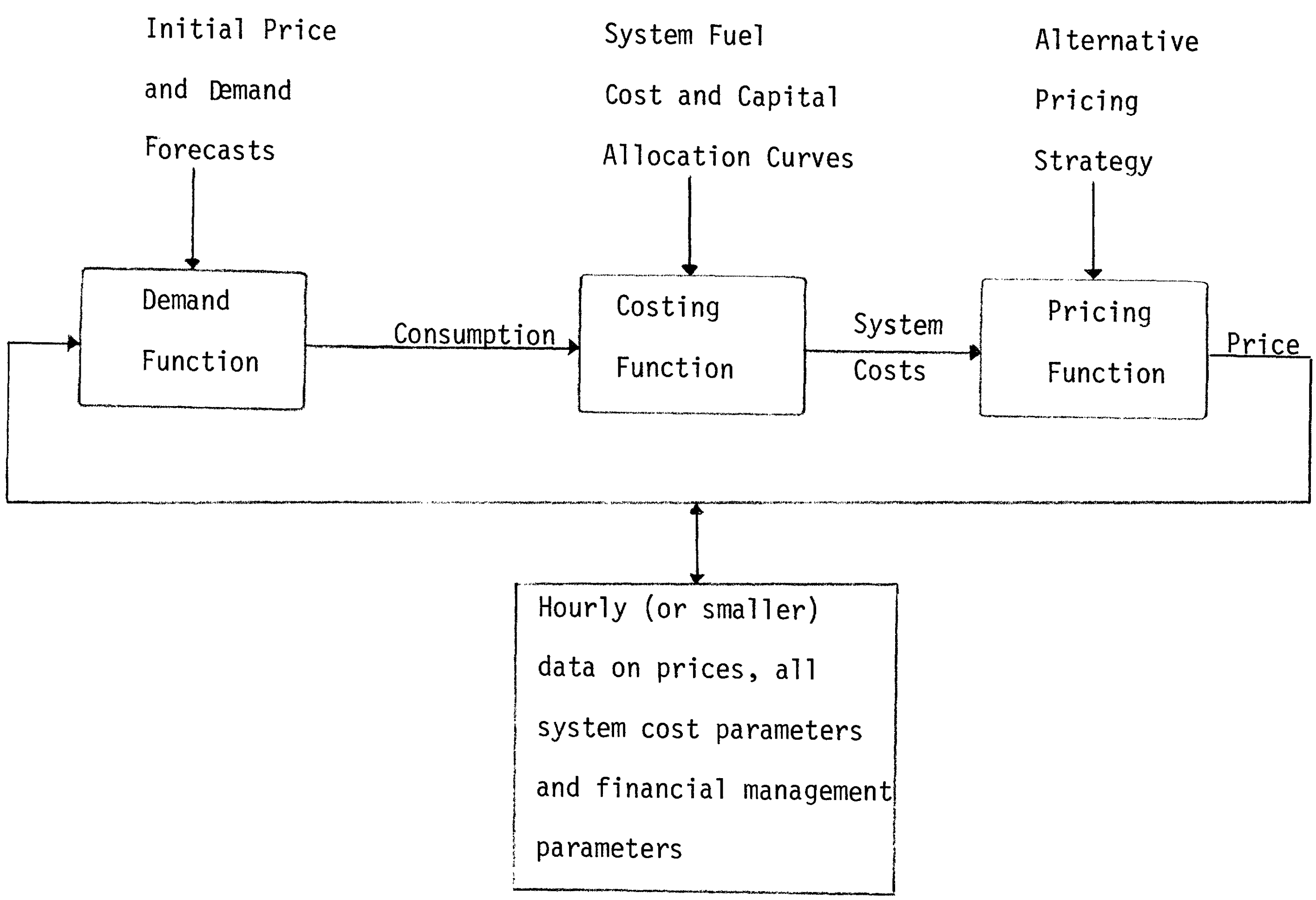
Case 4: The capital costs here are, again, the same for all periods, but are based on the annual capital costs incurred if all generating units were replaced at current prices for those units. Fuel costs are again the marginal fuel cost and the price set is the sum of these two costs.

Case 5: The capital costs are allocated capital costs but with replacement costs of generating units being used to compute the average capital costs for all units used to meet an interval's demand. The price is set by adding to this cost the marginal fuel cost.

FIGURE 2.1

Simplified Production Costing Model

Flow Diagram



Case 6: The price in this case is set by adding the marginal fuel cost and the averge capital cost of electricity generated from the marginal unit. Both capital and fuel costs are included in prices for each period of the day.

2.5 Model Description

The model is initiated from an annual run of SYSGEN, a flexible electric utility production costing and reliability model, which is described in Finger (1979). SYSGEN estimates individual plant capacity factors, taking into account forced outages and maintenance schedules.

Capital costs, either flat average costs, or fully allocated costs are computed using annual "cost-carrying factors" which have been provided by New England Electric. They are a proportion of either the original gross investment in, or the replacement value of, each generating unit and include the reveue that must be achieved in order to achieve the utility's allowed return on investment, Federal, state and local taxes, and depreciation. The cost-carrying factors are listed on Table 2.1.

The actual simulation of the utility customer interaction is portrayed in the flow-diagram of Figure 2.1. The simulation is initiated by reading the demand for the first one-hour interval of the week being modeled. The model then generates the price that the utility would charge for electricity generated to meet that demand level, depending upon which formula was imposed. If demand is at all elastic, the model computes the new demand level at that price, computes a new price based on that demand and iterates until convergence is achieved.

Simulations are repeated for each hour. The model also keeps track of total revenues, total costs, fuel consumption and the mean and variance of prices. Output is in either numeric or graphical form.

2.6 Results

As discussed above, the purpose of the analyses carried out has been to evaluate the interperiod consistency of rates set by using the spot pricing concept, to evaluate the predictability of rates given the concept and to evaluate the potential for energy savings given a level of elasticity which might apply in any specific situation. In addition, it is important to analyze the impact of prices of a scenario in which a major generation source was not available. The section which follows will cover each of these four points.

Interperiod consistency: As can be seen from Figure 2.2, the hourly demand curves for the three weeks being studied (April, August and December) are relatively smooth, though, particularly during the peak months, they do show specific, relatively sharp changes from one hour to the next. Figures 2.3 through 2.8 represent graphs of price of electric power given the utility system discussed above and the pricing scenarios discussed in the preceeding section.* From these graphs a number of specific conclusions can be drawn. The most important is that, while there are sharp steps in price (representing changes most frequently in the marginal or in the incremental generating source), the system does

* It should be noted that Figure 2 contains the full range of plotted information, average capital cost, average fuel cost, incremental and marginal fuel cost (assuming current New England market prices represent the marginal fuel cost) and the calculated spot price of electricity.

FIGURE 2.2

Weekly Demand Profiles

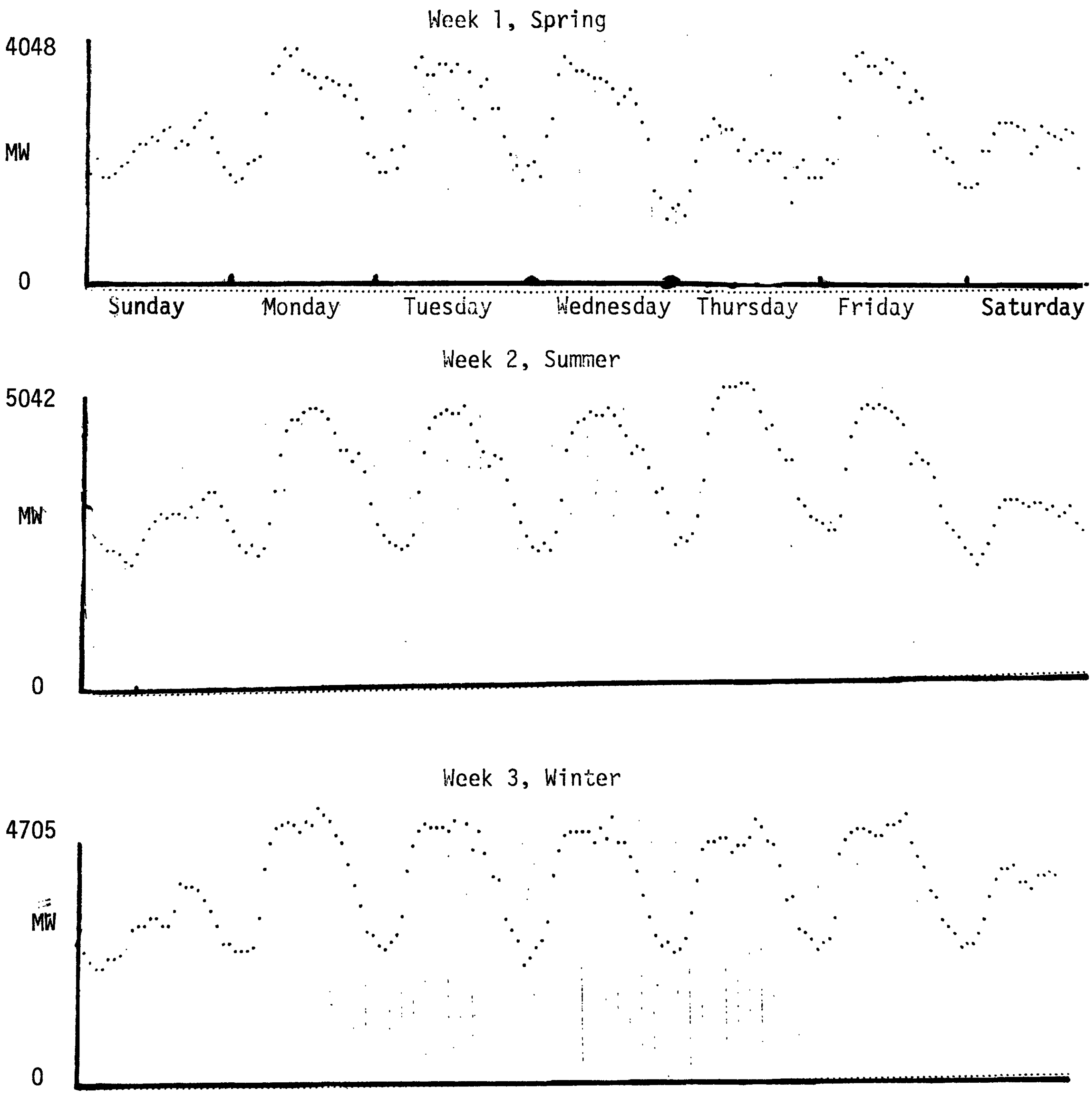


FIGURE 2.3

BASE CASE PRICE

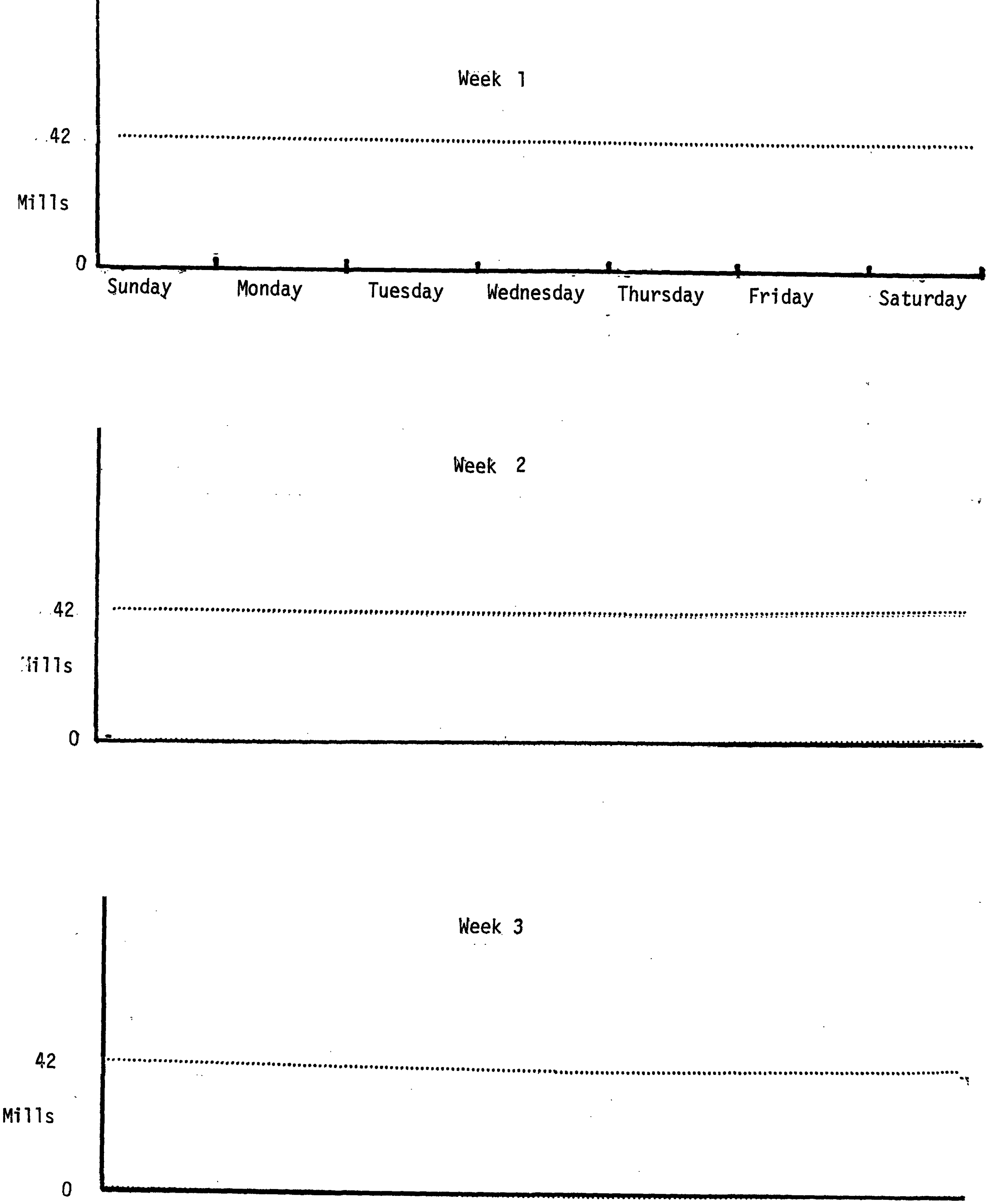
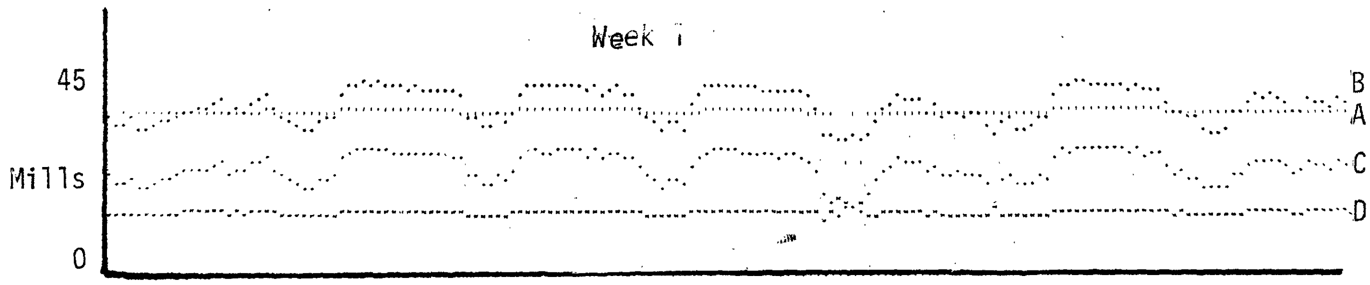
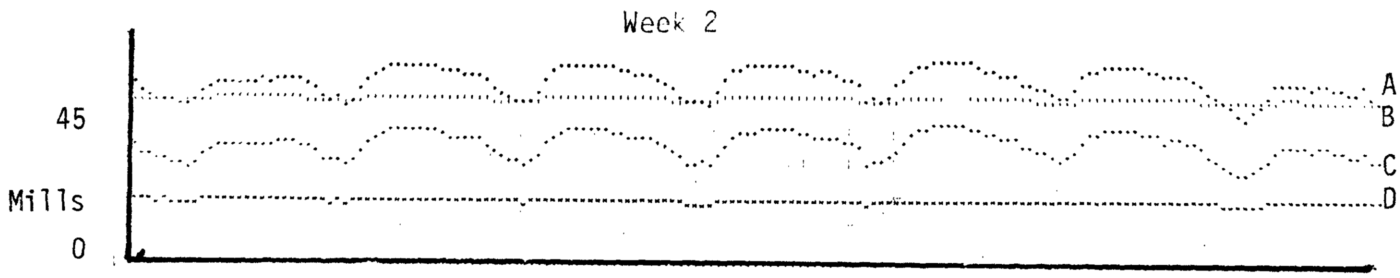
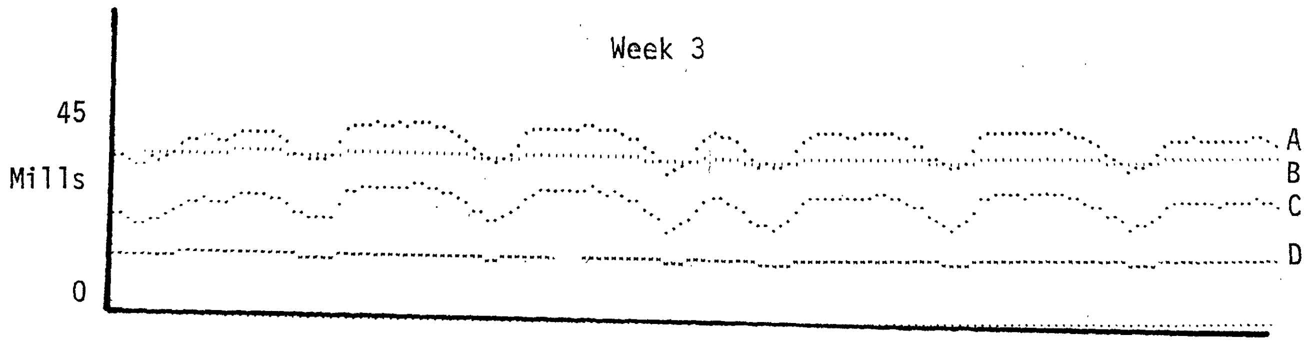


FIGURE 2.4

Case 2 Prices *







A. Price
B. Marginal or Incremental Fuel Cost (Assumed Same Given Present Fuel Costs)
C. Average Fuel Cost
D. Allocated Capital Cost

FIGURE 2.5
CASE 3 PRICE

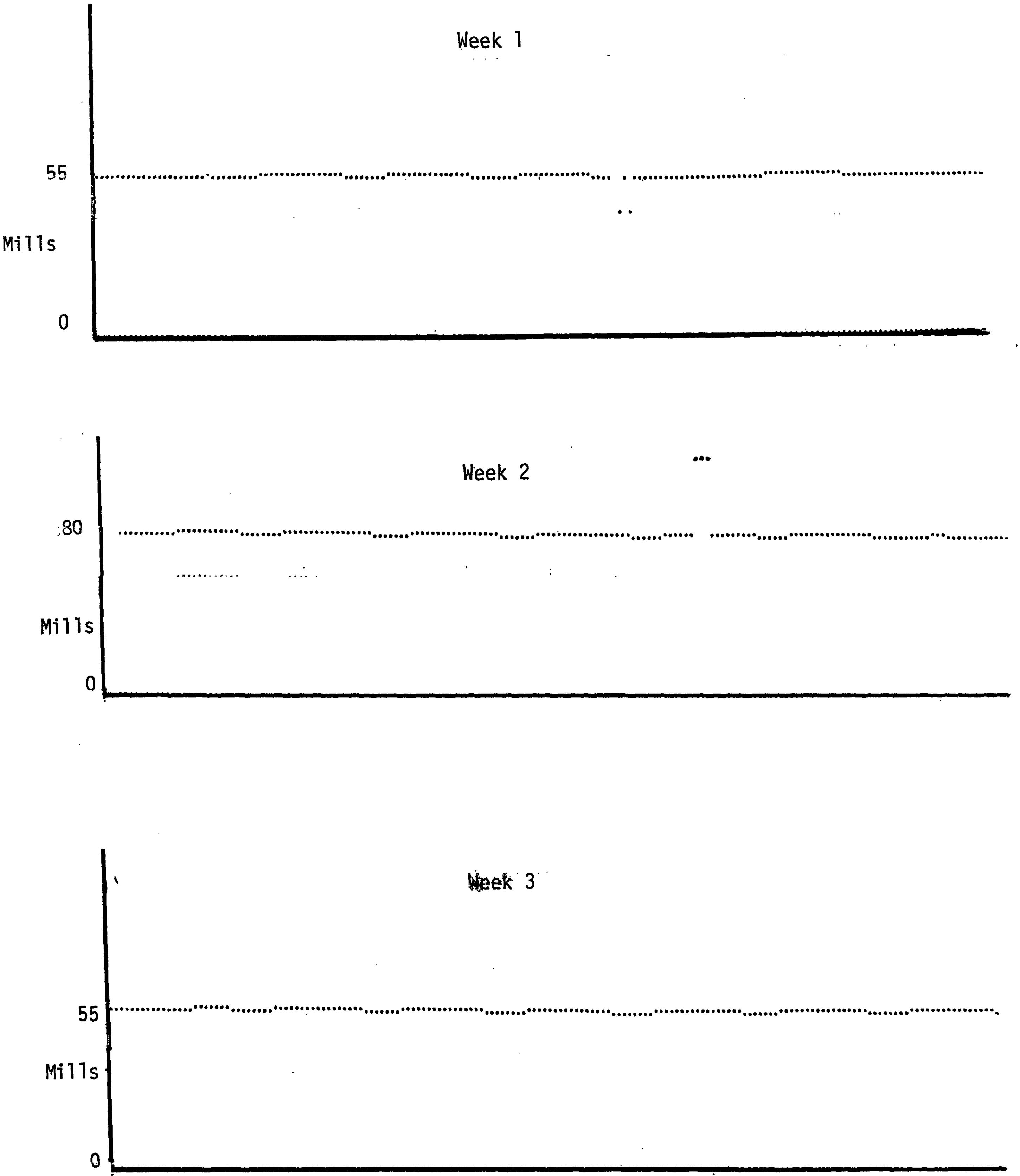


FIGURE 2.6

CASE 4 PRICE

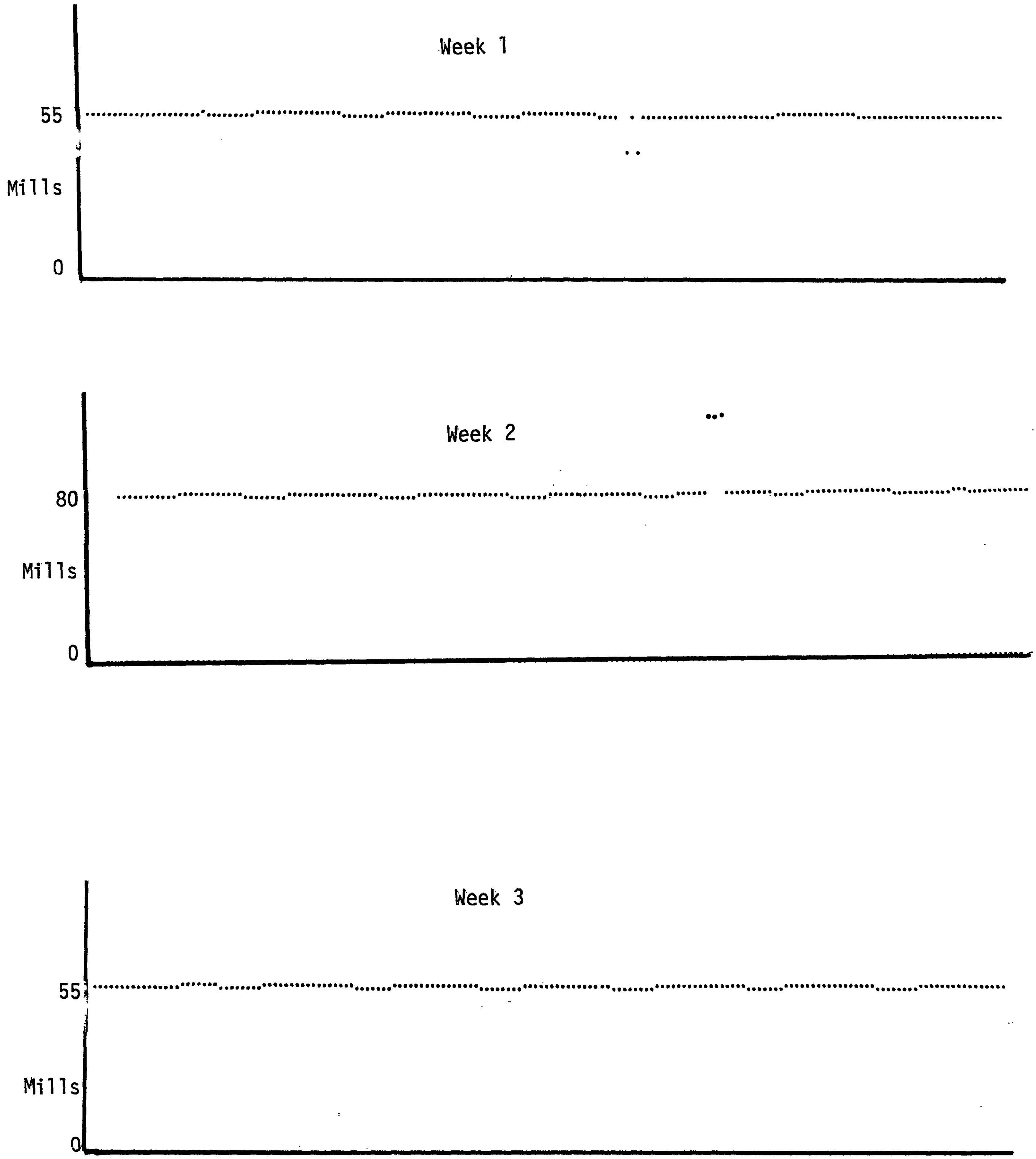
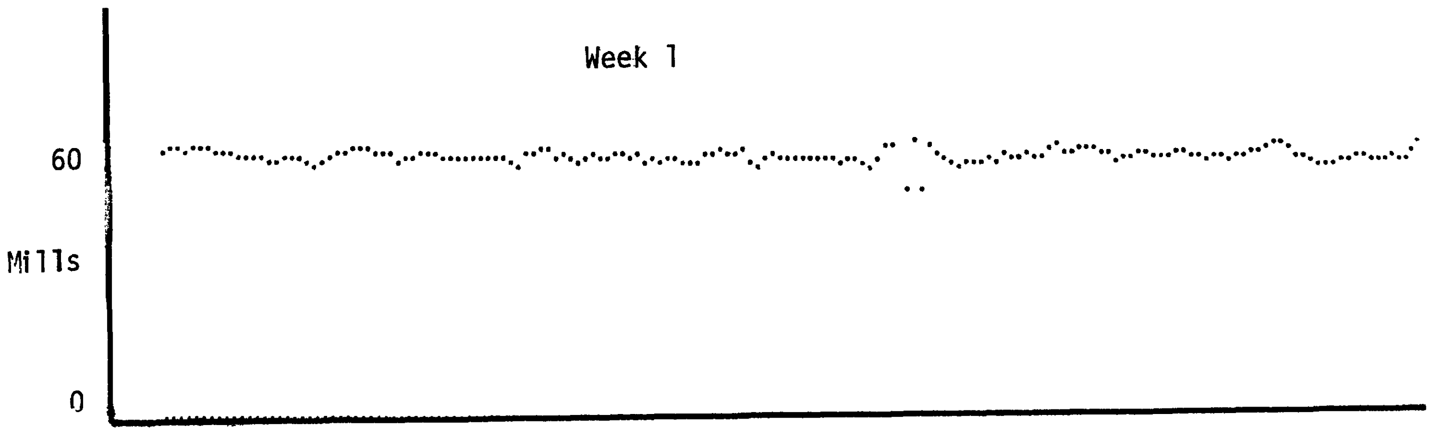
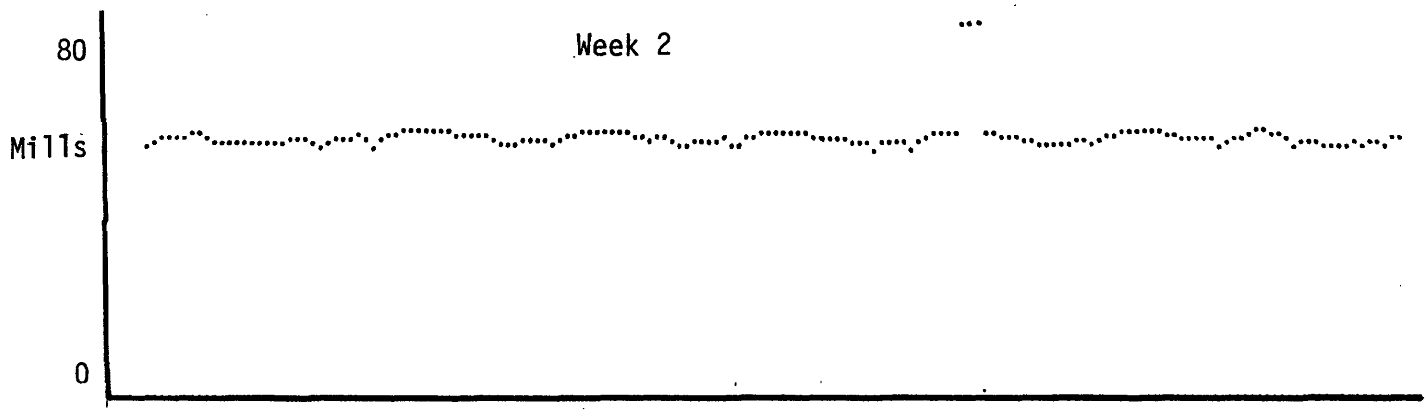


FIGURE 2.7
CASE 5 PRICE





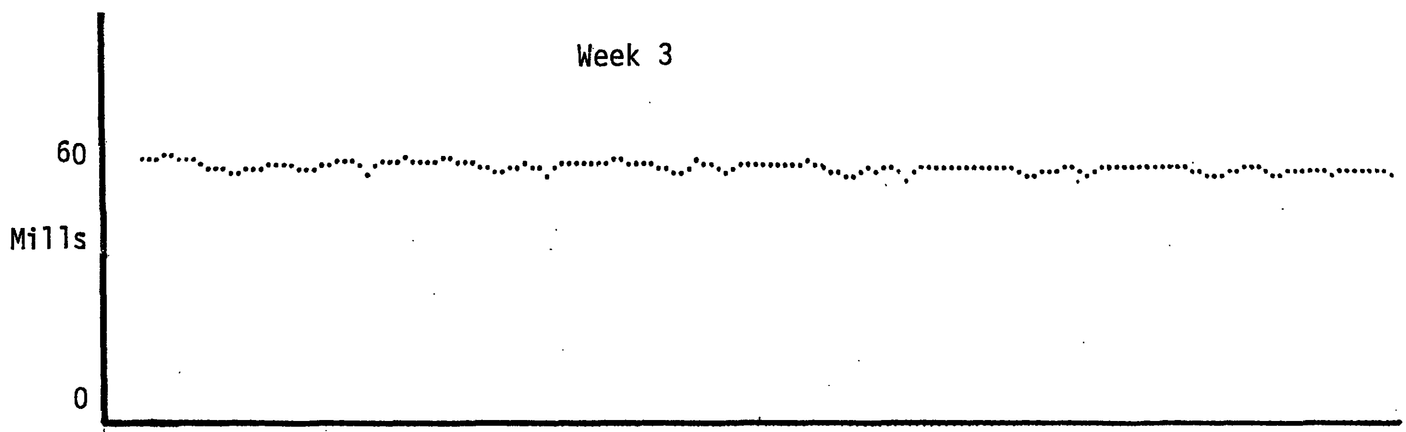
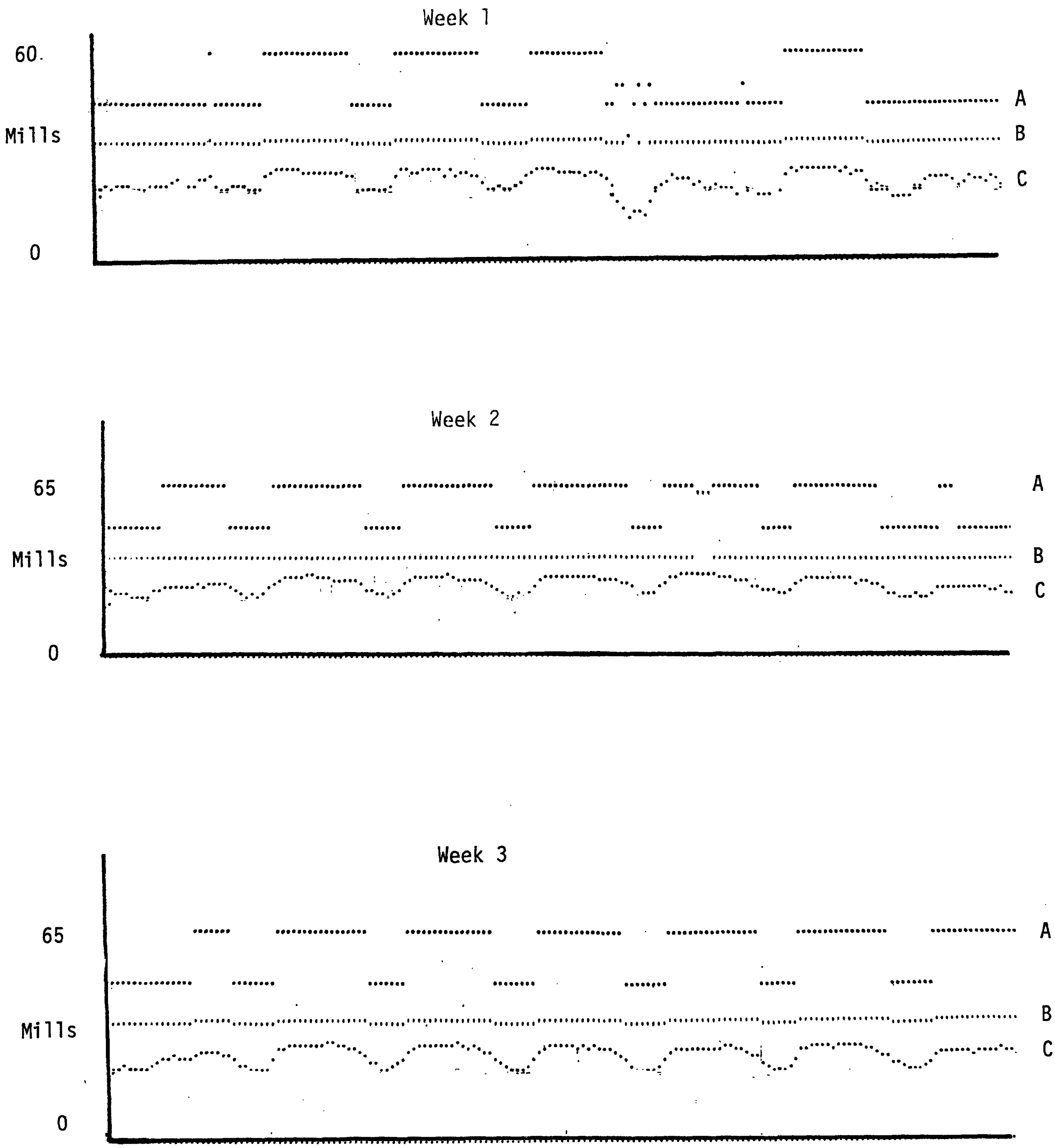


FIGURE 2.8

CASE 6 PRICES



A. Price
B. Marginal or Incremental Fuel Cost (See Figure 4)
C. Average Fuel Cost

not tend to show sharp interperiod jumps, i.e., there is not a tendency for prices to move up and down sharply over sets of sequential time periods. Table 2 presents a summary of the mean, standard deviation and maximum and minimum values for prices in each of the cases studied.
It is interesting to note that the distribustions are skewed to the low side. The pricing schemes result in relatively tight distributions with the majority of hours experiencing prices below the weekly mean.

A final point to note is that the spot pricing concept has been proposed for periods of time less than one hour. Given the evidence to date, there is little reason to believe that for time periods of less than one hour extreme fluctions will be seen, though clearly the price will fluctuate more than is shown in the one hour simulation. The fact that the simulation presented here is for a simplified utility genertion system with relatively few production units, and with flat heat-rate curves means that the simulation will show greater jumps in prices than will occur in the real world given large numbers of generating units.
Predictability: Referring again to Figures 2.3 through 2.7, it is possible to visually evaluate the predictability of rates from one time period to the next given very limited data. Weekday prices in each of the three week periods analyzed can be predicted with high accuracy knowing no more than the price available during the same time period on the previous weekday. Weekend prices appear equally consistent, though information concerning the previous Saturday or Sunday would be most useful in prediction of weekend or holiday prices. If one adds only one additional datum, hourly weather prediction, it is probable that nearly

TABLE 2.2

PRICES UNDER ALTERNATIVE SCENARIOS
(in Mills/Kwh)

	WEEK	MEAN	ST. DEV.	MAX.	MIN.
BASE	1	42	-	42	42
	2	42	-	42	42
	3	42	-	42	42
CASE 1	1	37	3	42	27
	2	40	3	44	33
	3	40	3	44	34
CASE 2	1	38	4	43	30
	2	40	3	45	32
	3	40	3	44	33
CASE 3	1	50	2	51	27
	2	51	3	75	50
	3	51	0.5	51	50
CASE 4	1	50	2	51	27
	2	51	3	75	50
	3	51	0.5	51	50
CASE 5	1	57	2	61	38
	2	58	4	83	55
	3	57	1	59	55
CASE 6	1	54	8	64	38
	2	59	12	122	48
	3	58	8	64	48
OUTAGE 5	1	56	1	57	53
	2	62	12	87	54
	3	58	6	85	53
OUTAGE 6	1	59	7	64	48
	2	76	25	122	48
	3	65	15	122	48
ELASTIC 2	1	37	4	42	30
	2	40	3	44	40
	3	40	3	44	33
ELASTIC 6	1	54	7	64	38
	2	57	8	64	48
	3	57	8	64	48

all of the hourly variability in the price from one day to the next can be explained. The one circumstance in which this is not the case is that in which there is a forced outage, particularly if such an outage occurs during a time period in which the system is at or near its peak. Under such circumstances there will be price increases in those pricing schemes in which incremental or marginal capital and/or fuel costs are charged. While the predictability of such an event is low, a probability distribution for the occurance of the event can be constructed and the distribution of likely prices under such circumstances can be readily defined.

2.7 Catastrophic Plant Failure or Forced Outage: As discussed above, a major forced outage, particularly those occurring at or near the system peak, will have a significant impact on the price charged for electric power given the majority of the pricing schemes evaluated in this paper. Figures 2.9 and 2.10 show the variability in prices given the removal from the generating stock of 600 MW of nuclear capacity. Because the synthetic utility developed contained limited reserve capacity (roughly 10%), the cases analyzed showed significant increases in price which reflected additional periods in which peaking equipment was required to meet the load. In both pricing cases chosen, cases 5 and 6, the system was taxed to its fullest during peak periods and as a result the prices reached levels in excess of 100 mills. The reader should also see Part 5 of the is report for a discussion of the spot price implications of the "quality of supply" component which becomes significant at times in which the system may approach its limits and be in some potential danger of collapse.

FIGURE 2.9

CASE 5 PRICES
WITH REMOVAL OF 600 MW

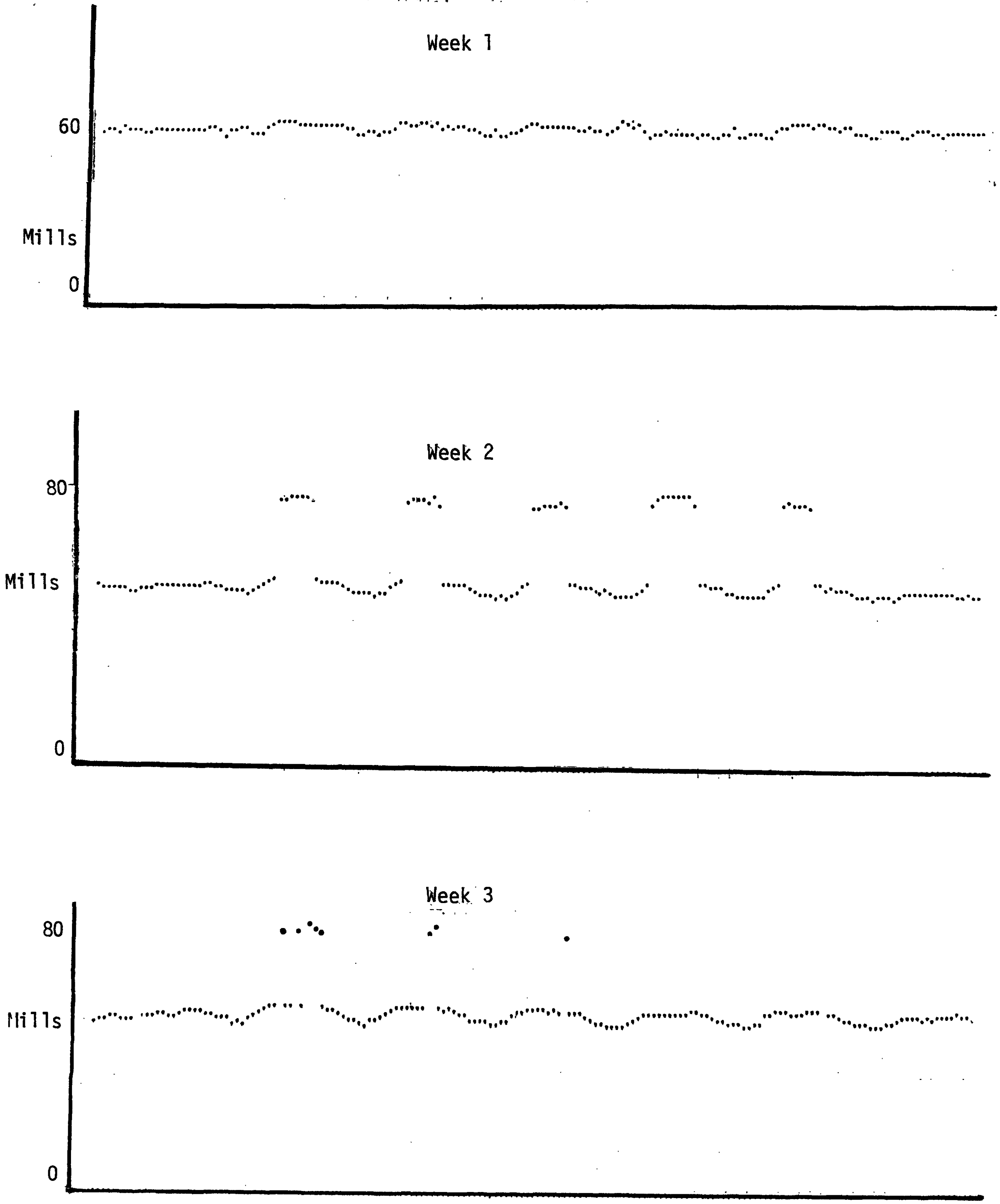
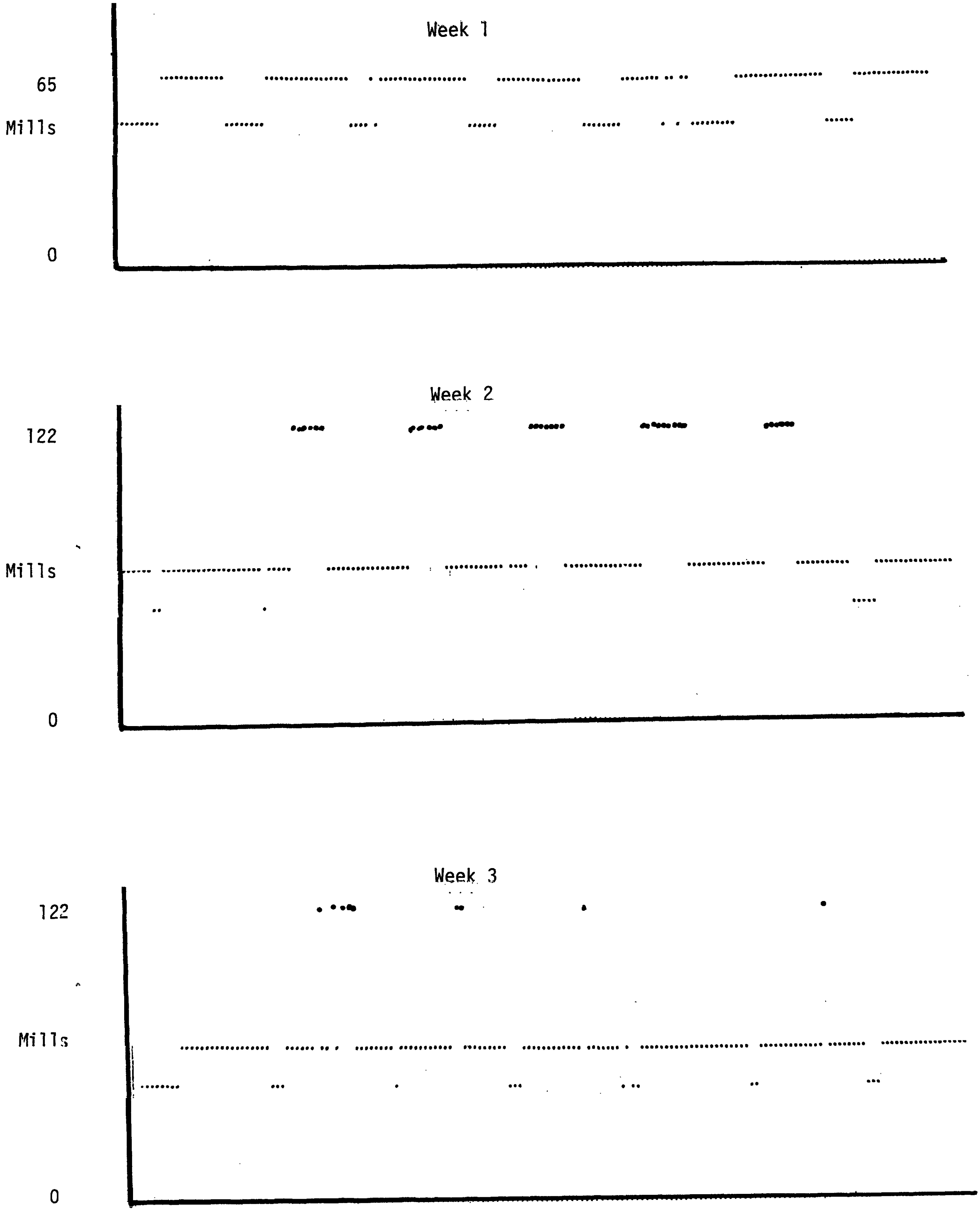


FIGURE 2.10

CASE 6 PRICES
WITH REMOVAL OF 600 MW



2.8 Elasticity: A significant purpose in time variant electric power rates is the modification of consumer behavior as a function of price (elasticity). The traditional concepts of elasticity do not cover the time intervals implied in the frequent movement of prices in the Homeostatic Control concept. Some work is being done to estimate price responses to regular, TOD price schedules. As a result, while it is not possible to predict empirically the response of industrial customers to changes in price which might occur either hourly or on the proposed shorter time periods, we can be confident that some price response will exist. In part this is because the consistency of pricing changes throughtout the day, throughout the week and between seasons would allow consumers to respond in their production process/patterns of consumption with both short- and long-run elastic responses.

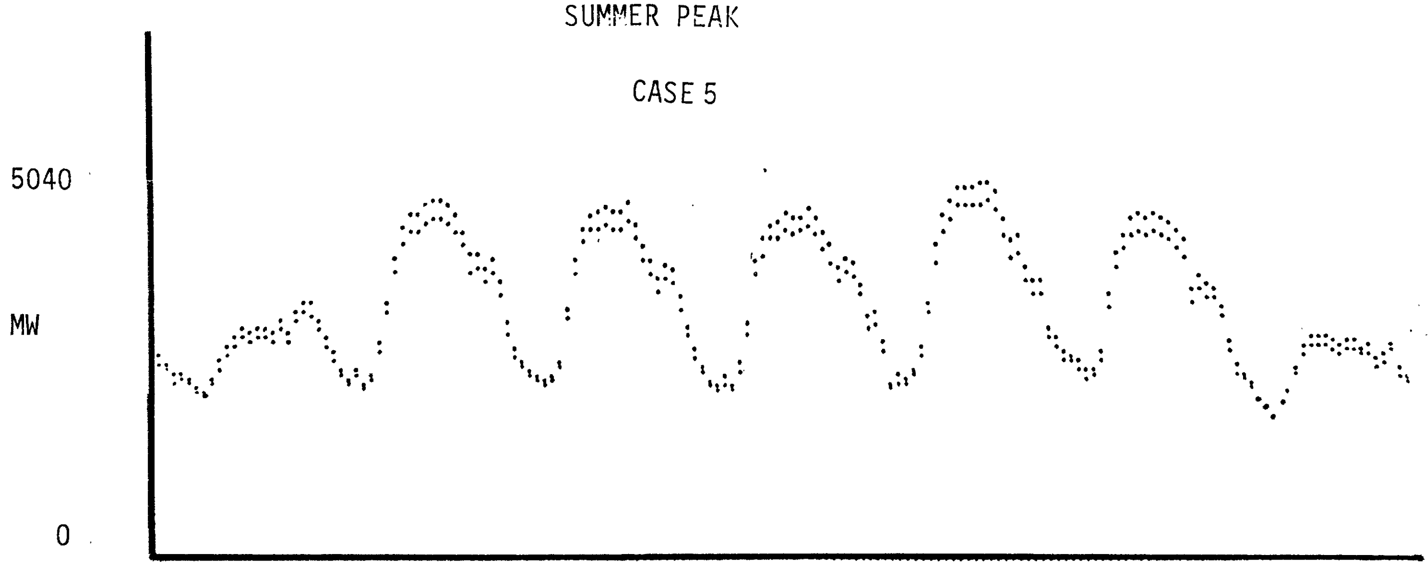
Figure 2.11 show two cases, (two and six), of changes in demand as a function of an assumed elasticity of 0.1 and a scenario in which energy consumption is not held constant. As would be expected, the overall impact is to shave the peak significantly and thereby to reduce the price charged by the utility for peak power, particularly given pricing schemes such as cases five and six in which there are very large differentials in price between the base and peak periods. Again, as would be expected, there are no dramatic changes in price seen given this highly simplified scenario. Considerable additional research effort is required in this area to evaluate the potential for shifting of load and the resultant price changes which this would bring about.

FIGURE 2.11

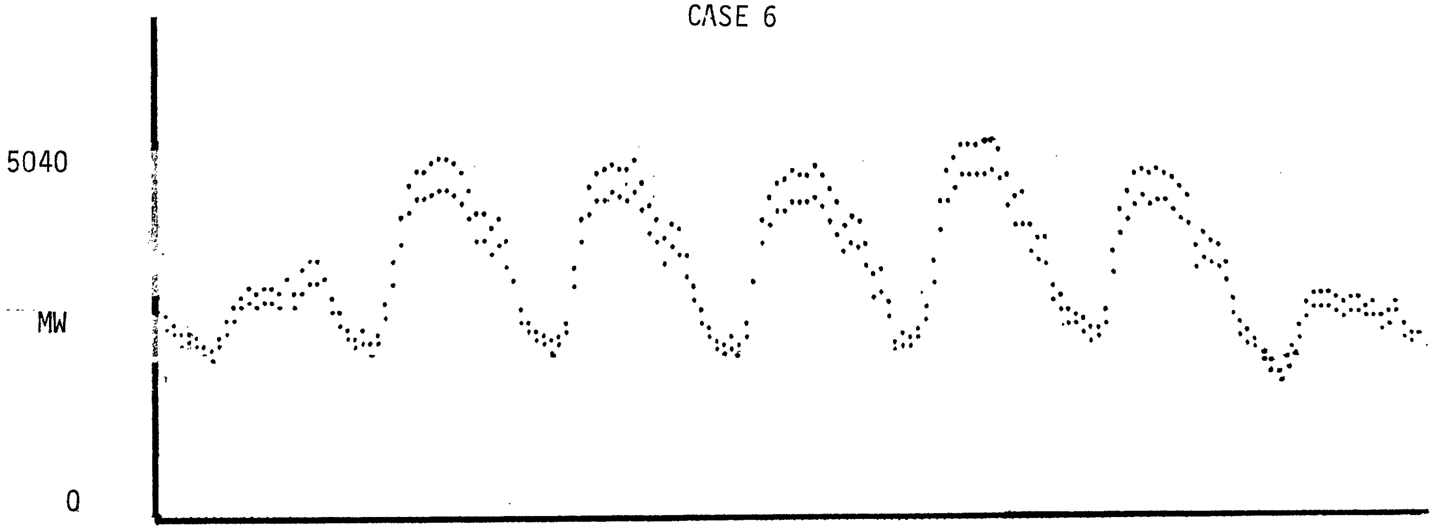
DEMAND ELASTICITY RESPONSE*

SUMMER PEAK

CASE 5



CASE 6



* Assumed Elasticity = 0.1

Upper line forecasted demand
Lower line elastic demand

2.9 Conclusions

The analyses discussed above have pointed to three significant conclusions concerning the potential for pricing schemes such as that proposed; these conclusions relating to interperiod consistency, predictability and consumer response. The most significant finding has been that the prices from period to period are consistent and are predictable. This consistency and predictability allows a customer to respond to spot prices as a regular operating activity rather than as a system of constant emergency. At the same time, however, the customer is advised, via price, of any emergency conditions which do exist within the utility generation and distribution system and is able to respond to these conditions. From the point of view of the initial analyses carried out, the concept of spot pricing will have the advantages discussed in the early paragraphs of this paper, namely that the scheme will eliminate the current problem in time-to-day pricing in defining the time periods for which specific tariffs will apply and will eliminate the economic inefficiencies inherent in infrequent utility commission rate reviews, i.e., the Averch-Johnson effect and inefficiencies caused by automatic rate adjustments in fuel costs. There are still, however, a number of issues which need to be developed to analyze fully the potential for spot-pricing within the overall scheme of Homeostatic Control.

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2.10 Discussion

Three questions were raised during the discussion which followed the presentation of the spot pricing paper. These questions centered around the following issues: (1) efficiency and equity, (2) predictability, and (3) implementability. The paper itself focused in large part on the issues of predictability of prices given limited information. The discussion which followed the paper's presentation accepted the conclusions of the authors with regard to (1) predictability of the prices given the information available, (2) the impact analyses on elasticities in so far as the analysis had gone to date, and (3) the impact of major system interruptions in so far as the simplified production costing model used was able to indicate the level of price change which would be inherent in such an analysis. Questions of implementability were generally held to a later discussion of consumer response and quality of supply, though, as will be discussed below, there were questions concerning the rationale for implementing a system with such short time blocks.

The major area of discussion concerning pricing centered around the statement by the authors that the spot pricing scheme as proposed would be equally applicable to average costing schemes as to marginal costing schemes. However, the average costing schemes would not give the customer signals as dramatic (or as economically correct) as the marginal costing schemes. But they would, none the less, give price signals which reflected increased utility costs of generation. The discussion then centered on the use and definition of marginal cost pricing for electric power. In that discussion it was suggested that the definition used in the spot pricing paper was inconsistent with previous work, a point accepted by the author. The most generally accepted definition was that marginal cost pricing is both a measurement of the response change (to a change in demand) by the system planner who makes long-range decisions and by the system dispatcher who is responsible for short run, moment-to-moment decisions. Stated in this manner long-run marginal cost pricing involves primarily capital costs, i.e. those costs associated with marginally increasing system capacity. In the short-run the marginal cost is one of fuel and operating costs (given capital is either available or not available in the moment-to-moment time frame).

In contrast to the definition above, the Spot Price analysis presented utilized a concept of marginal pricing, allowed by the spot price formulation but not by other structures, which calculated the price of electricity on the basis of both the marginal cost of <u>fuel</u> (short term definition) and the <u>allocated capital cost</u> of the marginal unit of generation. In this manner the spot pricing system allowed for both the allocated marginal capital and the operating costs to be included within the rate. The conclusion of this discussion among the economists present was that marginal costing was the correct method but that the definition of marginal cost was ambiguous. Little discussion was forthcoming on the author's point that it was possible using spot pricing to accept average or embedded costing formulae as easily as marginal costing formulae into a spot pricing scheme. Spot pricing is not the only pricing scheme which would be available to customers. Customers would be able to choose that scheme, including flat rates, which most closely fit their load requirement and production/consumption mix.

A second major area of discussion surrounded the issue of the advantages of spot pricing relative to systems available today such as time-of-day pricing or even flat rates. The basic question raised was one of the objective function associated with such a scheme and the relative costs and benefits of installation of such a highly variable pricing structure. The discussion provided both the positive and the negative implications of such a scheme. The most significant question was that of the objective function, or stated differently, what would one expect to gain through such a pricing system? The answer to this question was debated in such terms as cost minimization and overall economic efficiency. The issue was not fully resolved until discussions in a subsequent session in which the definition generally agreed upon was "cost minimization on <u>both the supply and demand side</u> subject to a set of constraints which would in general be related to environmental issues, etc."

On the negative side of the issue it was pointed out that the spot pricing concept would have a significant implementation cost above that for either flat rates or, more relevantly, for time-of-day costs, and spot pricing might have little if any additional benefits. A second set of negative comments were raised around the issue of responsiveness or potential for response on the part of small consumers. Here the discussion was both focused forward to the session on consumer response and the authors pointed out that the spot pricing scheme was focused primarily on the large energy consumer and did not preclude in any way the use of a combination of rate formulae and schedules responsive to customer needs. A third set of negative comments was raised on the manner of implementation of changes in the spot price as individual utilities add to their capital stock. The example given was one of the addition of a transmission line and when the utility would be allowed to add this capital cost into their rate base. Related to this question was that of how the losses in equipment for either the short- or long-term would be reflected in the formulae presented to the consumers. The discussion and solution suggested that such problems would be handled much as they are today through hearings before the PUC's and that such changes would not be expected to be automatically or instantaneously entered into the rate. The following question pointed to the possibility of "cheating" under such a system but was promptly answered by a utility commissionner who indicated that the cheating or inefficient allocation problem would be no different than that encountered in the fuel escalation clauses which had been handled quite effectively by the PUC wherein the costs incorrectly allocated had been disallowed to the utility.

The discussion then focused on a set of positive attributes of the spot pricing scheme. The first was that the spot pricing concept was not totally original but had been proposed by Professor William Vickery, among others. The spot pricing concept is presently in partial practice within the utility industry with sales of power between utilities. Second, as mentioned above, the concept of changing prices reflecting a formulae rather than a fixed schedule is an accepted pricing scheme utilized through the present fuel adjustment clauses. Third, the concept of large consumer response to such rapidly changing prices is being tested in San Diego, California and appears to be working well within that environment and therefore the suggestion should, when combined with the hardware proposed, function to minimize costs.

Other issues which arose were spot pricing versus long-term contracts. While spot pricing is not so different from the commodity exchange with bidding occurring on both spot and futures markets, the real question is whether or not spot pricing for energy, in this case electrical energy, is superior to providing electrical energy through a long-term contract as is done today. The uncertainties associated with continuously changing prices on short or no notice raised specific concerns among the industrial discussants particularly in terms of their ability to respond effectively under these conditions.

A significant discussion surrounded the issue of the benefits that one could expect to accrue from a give minute interval pricing structure. It was suggested that such a structure would be, in effect, a form of price rationing which would have the effect of strongly encouraging the participating customer to use economic dispatch of his power needs, providing a means of eliminating much of the need for interruptible loads in which the customer has little if any say in the decision-making process. A related issue concerned the benefit of a five minute interval pricing structure versus the cost of putting in a communications link to accomplish it. Here again, it was pointed out that communications links of this type are already in use in similar forms in other industries, or in the case of San Diego Gas and Electric, are already in use between the utility and specific of its customers. Thus, the additional cost of developing a two-way communication system, given the rapidly decreasing costs of communication technology, would appear to be not as negative as to make the costs outweight the benefits.

In summary, the discussion of the first conference session wandered beyond the narrow bounds which the authors had created within the discussion paper itself to look more broadly at a number of aspects of the proposed Homeostatic Control system. The queries raised by both discussants and the general group discussion which followed confirmed the initial analyses presented. A set of issues were raised, mainly those associated with the marginal value of homeostatic control over time-of-day pricing. Three were acknowledged to be significant and were taken up later in the discussion of customer responses. A first cut at a methodology and a set of numbers to answer this particular question was presented later in the conference. The debate of the correct rate setting formula in terms of marginal or average cost was never concluded though the most active participants clearly sided with marginal costing. Probably the most significant conclusion drawn by one participant toward the end of the discussion period was "What ever you do, don't study the concept to death, go try it!" This recommendation reappeared at a number of other points throughout the meeting.

Chapter 3: CUSTOMER RESPONSE SYSTEMS

3.1 Introduction

The key issues to be discussed in the conference in the area of Customer Response Systems are:

- What types of customer-utility interactions will the customer prefer or accept?
- How can and will customers respond to different types of customer-utility interaction?

The following material follows:

3.2 Customer Response Systems: Background

3.3 IEEE PAS Paper: "Impact of New Electronic Technologies to the Customer End of Distribution Automation and Control"

3.4 IEEE PAS Paper: "Physical Economic Analysis of Industrial Demand"

3.5 Homeostatic Control Initial Hardware Development

The material in (3.2) is intended to provide a broad background discussion on how industries can respond in an environment such as provided by homeostatic controls. Preprints of two papers to be presented at the IEEE PAS 1979 Summer Power Meeting are included as (3.3) and (3.4). "Impact of New Technologies" (3.3) provides more technical detail on the electronic and information flow associated with homeostatic control. "Physical Economic Analysis" (3.4) discusses the possibility of industrial customers rescheduling some operations in response to prices (the discussions are on time rates but also apply ways to homeostatic concepts). Section 3.5 presents a summary of the current status of hardware development.

3.2 Customer Response Systems: Background

Background discussions address the following questions:

1) What opportunities are presented by advances in communications and computation?
2) What types of information flows between utility and customer are possible?
3) What can customers do to take advantage of information exchange with the utility?
4) What are the major issues of customer acceptance?
5) What types of new customer capital equipment will be required?

3.2.1 Opportunities

In recent years there has been explosive growth in the capabilities of equipment used for computation. Computers are now available in both very large and very small sizes, with an enormous range of capabilities. Matching this growth has been a sharp reduction in their cost, so that today an enormous amount of computational capability can be had for very little money. Examples of equipment using small, inexpensive special purpose computers include all of the little hand-held calculators that are now so common, as well as the electronic games that have become popular recently. Many systems concepts which, until recently, were prohibitively costly are now possible because of advances in microelectronics. In the future, it is reasonable to expect that the intelligence of a controller will be a very small part of the cost.

During the last several years a number of groups have carried out research and development of systems for implementing two-way communications between a utility and its customers. As a result of these studies, several different types of communication system have been demonstrated to be feasible. Generally, these systems have been intended for use in automatic meter reading and direct load control. Communication media which have been used in successful demonstrations include power line carrier, telephone lines, radio wave, and power frequency ripple. Systems employing each of these, and/or combinations of these, are currently operational.

This revolution in electronics provides many opportunities for advancements in equipment to be used for distribution automation and control, load management, automatic meter reading, variable price metering, small scale load shedding, and many other purposes.

Computers are now used in load management schemes in some industrial and commercial sites. MIT, for example, has a mini-computer which serves to control the environmental control systems within some of the Institute's buildings. One of the functions of this machine is to reduce the fifteen minute peak load, thus to save on demand charges. It is logical to expect that, as the opportunities for economical application expand, more and more customers will choose to have some of their energy-using functions be controlled by a computer. As the benefits of mass production reduce costs, even small commercial and residential customers may be expected to make use of sophisticated energy control systems.

3.2.2 Possible Information Flows

It is possible to envision many different types and combinations of types of communications between the utility and its customers. The case of Homeostatic Control will be used as a basis for this discussion. At the end, other types of information flow will be considered. There are three entirely different types of communication which must be considered here, and it is quite important to understand the distinction between them. The first type of communication is between the central utility and equipment belonging to the utility at the customer's site. Generally, this equipment will be in place of the meter (today this is a watthour meter, while under Homeostatic control it would be somewhat more sophisticated and would so be a fancier name). The second type of communication is between the utility apparatus on the customer's site and the customer or the customer's own equipment. Finally, the customer's equipment will pass information around a communications system entirely local to the site. Under the Homeostatic control concept, there is an importation segregation of information flows, maintained by the equipment at the interface between utility and customer equipment. At that point, all communication of information from the customer equipment to the utility would be controlled by the customer's own equipment. The utility would have no capability of "looking into" the customer's site.

Various types of information flows are required by Homeostatic Control. The data link between the utility and the meter would carry at least two prices for electrical energy: the "buy" price, and the "buy-back" price. The first of these is the price paid by the customer at any given time period. The second price is the price paid by the utility for power delivered by the customer from, say, on-site generation. There may be additional prices reflecting the value of reactive power, etc. In addition, the data line would carry meter polling requests from the utility and, perhaps, information such as forecasts of future price to allow the customer some time to adjust energy use. Information returning over this line would include meter readings and, perhaps, rate confirmation information.

Of the information on the utility-meter link, some is passed on to the customer. These include all of the prices and price forecasts. It will not, of course, be necessary to pass on such information as polling requests although certain issues of privacy, discussed below, may make this desireable.

Several other types of information transfer may be desired by Homeostatic Control. For example, it would be possible for the utility-customer data link to mediate a sophisticated transaction regarding interruptible power sale. The utility, in a quest for a certain amount of rapidly interruptible power, might hold an electronic auction among its customers. Under such a scheme, it would offer an increasing price differential for the sale of energy that could be rapidly disconnected. Customers (or more likely, customers' computers) would "bid" for such interruptible power, until the utility had met its requirements. The sequence of offer, accept, and of course the attendant dissent (in case of emergency) could be sent over the utility-to-customer data link.

Another possible type of information that might be carried on this data channel would implement a utility control scheme that might be called "microshedding." Under emergency conditions, certain classes of load might be deemed to be sheddable. The utility would send out a microshedding instruction over the data link, resulting in the disconnection of the sheddable load. By pre-arrangement, several different classes of load could be arranged into a priority scheme, thus allowing for a series of load shedding steps, which would be invoked in order, according to the severity of system emergency. The major advantage of this sort of a scheme is that it might avoid total disconnection of customers in the event of a severe system emergency, thus allowing them to maintain critical loads.

Yet another type of information transfer possible with the utility customer information link is actually already in use. This is direct control of customer loads. As an alternative to clock control of loads such as water and space heaters, direct control can prevent difficulties with time changes, clock inaccuracies and tampering.

3.2.3 Customer Use of Information

There are several identifiable uses for information passed on to the customer. Price information would be loaded into the variable rate watthour meter, to be used for establishing customer charges. It would also be transferred to the customer to allow the customer to re-schedule loads or to make other decisions regarding electric energy use. The utility would use a polling signal to recover from the meter such information as energy use (actually, in this case, it would be energy use weighted by price), and to verify the price stored in the meter. The existence of rapid, reliable communications and computer capability might also allow for the ready negotiation of interruptible load arrangements. For example, a customer computer might be programmed to accept the offer of interruptible power with a price reduction of at least a certain amount. Similarly, the utility might be able to offer such interruptible power only under certain circumstances. The negotiations for such interruptible power might, conceivably, be done completely automatically or, at least semi-automatically. The communications link might also be used to provide load shedding orders. Certain classes of customer load might be classified as sheddable, and thus be controlled, directly or indirectly through the customer computer by the utility.

There will, of course, be important limitations on the communications system. For example, with the type of communications systems now being proposed, bandwidth limitations restrict the capability of the system. Important restrictions include the inability to confirm the price transmitted to each customer meter in real time. Further, the communications system might not be able to confirm load shedding of each customer under emergency conditions. Fortunately, the computational abilities which may be built into utility equipment at the end of the distribution line can make up for most of these problems. In addition, certain other forms of communications system (dedicated wire or optical fiber), or of communications system arrangement (using computation at widely distributed locations) might overcome these limitations.

3.2.4 Customer Acceptance

It is necessary to consider what actions a customer might take to take advantage of information from Homeostatic Control. Many customers will be able to reschedule important loads to times when the price is low. Examples are heating, cooling, and pumping. It might be necessary to run certain processes only at times during the day when such processes are economical. Of course, some loads might be considered interruptible, and thus qualify for a reduced rate. The rate differential for interruption might be different for different loads, and so the utility might have to pay more to obtain the required volume of interruptible load at different times. Thus a customer might have a class of load that is interruptible at some times, but firm at others.

There is major uncertainty about the nature of customer response to the options presented here. For example, how would a customer respond to a (time-variable) spot price? This question is critically important, for it relates to the elasticity of demand. It is reasonable to expect that different types of load, representing different classes of process, will have different inherent elasticity of demand. It is reasonable to expect that the elasticity may be related to the value of the product in relation to the cost of the electric power consumed in its manufacture. Some processes have a greater value, in relation to the cost of electrical energy used, than others. Many commercial and, perhaps most residential uses will have a very small elasticity. That is, increases in price will have very little impact on demand. It is hard to imagine, for example, a department store or a home turning off the lights on a dark night because the price of electricity happens to be high.

The issue of elasticity of demand is made more complex by the possibility of load rescheduling. Many types of load processes can be rescheduled, or carried out at times during which the price of energy may be low. This is particularly true of such uses as space heating, pumping for domestic and irrigation uses, cooling, etc. In many cases, new equipment, such as storage tanks might be required to take advantages of time variable price, and so the true long-term elasticity of demand may not be observable, even to an experiment.

There is also the possibility of time variable prices, which imply very low rates at certain times, attracting new classes of load to the electric power system. For example, if cheap electricity were to become available at certain times of the day, electric space heating in conjunction with storage might become attractive. The possibility of this happening would be enhanced by the large-scale use of generation systems which are relatively capital intensive and fuel price insensitive, such as wind, solar, and nuclear sources. In fact, very wide price fluctuations might be expected on a system dominated by wind or solar generation, because of the intermittent nature of these sources. Such a system might have a very high load diversity factor, with the lowest prices occurring at the same time as peak system loads!

Customer response to the widespread use of interruptible load sales and microshedding is even more uncertain. For example, it is very difficult to predict just what sort of price differential would be required to get customers to accept interruptible power. For many classes of customers, generally residential and commercial, the existence of interruptible power must be essentially "transparent". That is, the customer must not be able to detect, or at least must not be inconvenienced by, load interruptions. It is not hard to envision completely transparent operation of certain types of load, which might be referred to as "energy" loads. Thus it is reasonable to expect that interruptible arrangements beyond this point is problematical. The ability to "flip a switch" has a considerable value.

All of this leaves a substantial question as to the ability of a utility system to use spot prices or interruptible contracts to help achieve a greater degree of system security and operational economy. This is clearly ground for further study.

There are many means at the customers disposal for affecting price response. The crudest form of response would be manual. A customer would watch the price (or set an alarm at a trigger price) and then go around turning things off. On the other hand, it is reasonable to expect that prices will vary in a fairly regular way. Based on a little observation and a knowledge of the weather and the day of the week, a customer should be able to predict the load fairly well. Thus pre-scheduled load behavior would be possible. Finally, a customer might have a computer do the load control. There are, of course, some computer based load controllers in existence now, so it is clear that this mode of control is already feasible. As the cost of computation goes down, the market for load controlling computers will improve. In fact, mass production of this equipment would bring the cost of load rescheduling equipment into the range of feasibility for small commercial and maybe even residential customers.

It should be noted that the economical implementation of mass produced load rescheduling equipment will depend upon easy installation. A load rescheduling computer will require a variety of types of information: price from the utility, process data (tank levels, storage temperatures), input from the operator, and so forth. It will also generate data to be transferred: commands to process equipment and operator information. Thus a data transfer medium will be required. The benefits of mass production and simple installation would be most easily achieved if a standard data bus were available. Just as much equipment is now plugged into a power bus of standard characteristics, installation of data handling and control equipment could be essentially a plug-in operation.

Privacy of customers will be a major issue if high speed, reliable two-way communications becomes a reality. Rapid meter polling would result in the accumulation of a lot of information about a customer. For example, a time-series chart about one's energy consumption could tell just how late that party lasted, and whether the host made it to Church in the morning. Ways of controlling the method of meter polling and access to the resulting information will have to be formulated. Customer acceptance of the variable rate meter will also be an issue. It will be necessary to convince people that this is not just another utility rip-off.

Security of the system will also be a major issue. Tampering with watthour meters is a major concern to utilities today. The more sophisticated meters offered by Homeostatic Control, while presenting a more complex problem for the would-be tamperer, also offer the sophisticated cheat a lot of opportunities. Very careful thought will have to be given to the communication system to reduct the opportunities for invasive tampering to, say, arrange for a bogus price signal to be applied to one's own meter.

3.2.5 Customer Equipment

A variety of customer investments and energy use changes is anticipated so they can take advantage of price variations. These actions would vary from re-scheduling loads to low cost times through running certain processes only when price permits to running or not running certain processes at all. Some of the customer responses will involve the installation of new capital equipment both for energy control operations and for alteration of process operations.

First, a customer could employ a fairly sophisticated communications and computation system. Such systems are already in place in some locations, generally those of very heavy energy users. It is to be expected that, as the incentives become greater and the price of electronics falls, the incidence of such systems will increase. A customer would typically have two basic elements to his energy control system. The first would be an energy controlling computer system. This computer could be as simple as something that alarms at a certain high (or low) price level or it might be as sophisticated as a machine that can be entrusted with negotiations of interruptible power agreements. The device would accept price, process, and control information and then control energy-using devices and processes. Information transfer and control would take place over the second important part of the customer's system, the data network. At the present time, both the computers and the data networks used for this type of control are large and custom built systems. It is reasonable to expect the effects of mass production to be felt in this business in the not too distant future so that these devices will come within the reach of even small customers. Customer site computation and communications is the subject of the paper which is attached to this section.

Second, customers would be expected to make new capital investments that would allow them to use electricity even more flexibly than they can with their current energy-using equipment. In industry, incremental capacity might be built for some types of energy-intensive equipment so that overall plant throughput could be achieved by running only during low spot price periods: examples include extra chippers, pumps, or pulverizers. In conjunction with this added capacity, new storage facilities are required to save the intermittently-operated process's inputs and outputs for coordination with other manufacturing stages:

examples are storage bins or tanks for pumped liquids. If rates were to dip low enough at times, the installation of heat pumps in conjunction with storage capacity might become feasible for space heating. Time variable prices would also affect competition between electricity and other energy sources for some processes. It is quite possible that dual-fuel process equipment might be manufactured. When electrical power is cheap, it would be used, but during times of expensive power, a switch would be made to other sources, such as natural gas. This raises the possibility that time variable prices might actually allow electricity to displace other fuels at certain times. Heat pumps and storage provive one example. If price fluctuations were wide enough, such a combination would become economically competitive with other common heat sources such as light oil or natural gas.

Over the long run, industries that operate their plants more flexibly might move to areas where fluctuating prices posed no large penalty, while industries that needed stable spot prices for electricity might be biased toward regions where expected or abnormal price changes were less likely.

Customer generation is a special class of the investments that are simplified under Homeostatic Control. This includes the typical emergency generators and cogeneration plants along with the less conventional renewable resource technologies. The customer and the utility would not be tied to a complex combination of stand-by charges, demand charges, capacity credits, and energy buy-back contracts. Instead the spot price information and the low costs for economic control of the generation would encourage operation almost as if the generator was dispatched directly by the utility. If the customer's generation fails, a price reflecting current cost conditions is paid rather than one based on an expected set of conditions -- if that current price is very high, the customer then has the option either to buy the power or to cut electricity consumption.

This customer generation could easily benefit the utility as well as the owner. Energency generation, triggered by an abnormally high spot price to the customer because of local distribution limitations, would reduce the customer's net load and benefit the utility by reducing line loads. Since increases in electricity cogeneration are most economic if they are coupled to a simultaneous increase in steam output, process steam use would be coordinated with utility-wide electricity needs not merely the single plant's electricity consumption

In certain types of power systems the time of minimum price might not be the time of minimum use. A system dominated by intermittent sources with limited controllability, such as wind or solar energy, might have generation that drives the price down dramatically when the wind is blowing or the sun is shining. In such systems energy using devices with large storage capacity would operate to take advantage of the cheap price, and might actually cause the system to produce maximum power at time of minimum price, contrary to the situation in a power system served primarily by fossil fuel generation.

3.3 IMPACT OF NEW ELECTRONIC TECHNOLOGIES TO THE CUSTOMER END OF DISTRIBUTION AUTOMATION AND CONTROL

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Abstract - Recent years have seen explosive growth in the areas of microelectronics, digital electronics and communications. The same time period has witnessed substantial pressure on energy prices. These two facts have motivated the formulation of advanced control schemes for electric utilities, to even out system load and to distribute costs in an economically optimal way. This paper describes ways in which the advances in electronic technology might be employed to help implement advanced control technologies.

INTRODUCTION

Recent years have seen explosive growth in the areas of microelectronics, digital electronics and communications. Performance of systems in these fields has improved dramatically while prices have fallen. These advances provide the means to build control systems that will, in the future, help improve the performance and reduce costs of electric power systems.

The rising cost of energy is providing pressure for changes in pricing structures to more fairly distribute the cost of providing electrical generation. Rising costs are also making nonconventional sources and co-generation more attractive. It is reasonable to expect these trends to continue.

Such influences, plus the opportunities presented by developments in electronics, have led toward the formulation of innovative concepts in Distribution Automation and Control and related fields. One new concept in this area is Homeostatic Control, described in a companion paper [1]. Implementation of these advanced approaches will require the development of specific types of electronic systems. Of particular interest is the type of system which will be required at the customer end of the distribution line.

Advanced concepts in power system control will require data transfer across the interface between distribution line and customer. Computation, control and monitoring systems will also be required. The purpose of this paper is to discuss how elements of new electronic technologies might be assembled to form a coherent, effective system at the customer site. The discussion is made with Homeostatic Control in mind, but the type of system described can implement other types of control strategies, separately or concurrently.

This paper is also a proposal for the development of certain types of electronic hardware, software, and standards. The implementation of the types of control structures described here would be greatly facilitated by the existence of standard data links.

New Electronic Hardware

Among the most impressive of all technological developments in recent years are the great advances that have been made in microelectronics. The industry has passed from Integrated Circuits through Large Scale Integration to Very Large Scale Integration. Single chips carrying as much complexity as the large computers of only a few years ago can now be produced for only a few dollars each, and the price/performance trends show no indication of saturation. Microelectronic circuits include general purpose devices (microprocessors and memories), and specialized devices (calculator chips, device controllers, communications link interfaces). Many system concepts which, until recently, were prohibitively costly are now possible because of advances in microelectronics. In the future it is reasonable to expect that the intelligence of a controller will be a very small part of the cost.

Data communications has enjoyed rapid advances because of the application of digital techniques and the development of new media. In particular, standardized interface hardware and protocols have enabled different manufacturers to produce devices that can interact with each other (even with devices made by the competition). A wide range of media for data communications is now available, ranging from carrier signals on power lines to optical fibers. The combination of the advances in both microprocessing and digital communication permits the development of sophisticated distributed processor control systems.

Requirements of a Very Advanced Control System

This discussion is cast in terms of Homeostatic Control. It will become clear, however, that the type of customer interface and control system described here would be useful for other control strategies and features.

Briefly, Homeostatic Control incorporates a strategy in which both customers and the power supply system each accommodate to the needs of the system as a whole. It incorporates two basic strategies:

1. Frequency Adaptive Power Energy Rescheduling (FAPER) is a means of short term system frequency control implemented by rescheduling energy loads. System frequency is used as a key: if frequency is low, FAPER turns energy loads off, while if frequency is high, FAPER turns energy loads on. The term energy load used in this context means a load that can be re-scheduled over a short period without adverse effect on the customer. Hot water heaters, space and process heating, electrolytic tanks, water pumping and many other types of loads are of this type.

2. Spot Pricing [2] is a means of allowing the price of electric power to reflect its true economic value. The spot price would vary with time, increasing as system load increases to reflect the fact that relatively expensive generation must be used at system peak load. It is expected that price variations will prompt customers to reschedule some uses of electric power away from times of system peak load. The Homeostatic Control concept of Spot Pricing differs from the notion of time-of-day rates in that the Spot Price would vary to reflect actual instantaneous system and load conditions.

Several capabilities are required in the control and communications system at the customer end of the distribution line. These are:

1. Communication from the power company to the customer and to the metering system. This is necessary in order to announce the spot price, and would be useful for other purposes.

To be presented at the IEEE Power Engineering Society, 1979 Summer Meeting, Vancouver, B.C. July, 1979

2. Communication from the customer-end metering system back to the power company. This is not necessary in the initial Homeostatic Control notion, but would, most likely, be necessary in any practical implementation. It would be used for verifying the spot price and for automatic meter reading.

3. Load level sensing. This is the front-end function of an energy meter. In addition to supplying information required for billing, this function could supply information on load responsiveness to frequency or other signals. The usefulness of this information will be discussed below.

4. Variable rate price integration. With variable rates it would be necessary to keep track of a customer's usage, not in terms of kilowatt hours, but rather in terms of money. This function must accept spot price and usage, multiply the two and integrate the result over time.

5. Frequency Detection. This is the front-end function of FAPER. Information from this function would be used to control energy rescheduling, and perhaps to determine load responsiveness.

6. Customer load scheduler. This function would accept data from other elements of the system and turn on or off customer loads.

7. Customer scheduler-to-load communications. Some link between the scheduler, other elements of the system, and loads which may be physically separated would be required.

System Description

Figure 1 shows a block diagram of a configuration for a customer control and communication system. The blocks in the diagram really refer to functions of the system, although in most cases they will correspond with specific pieces of hardware.

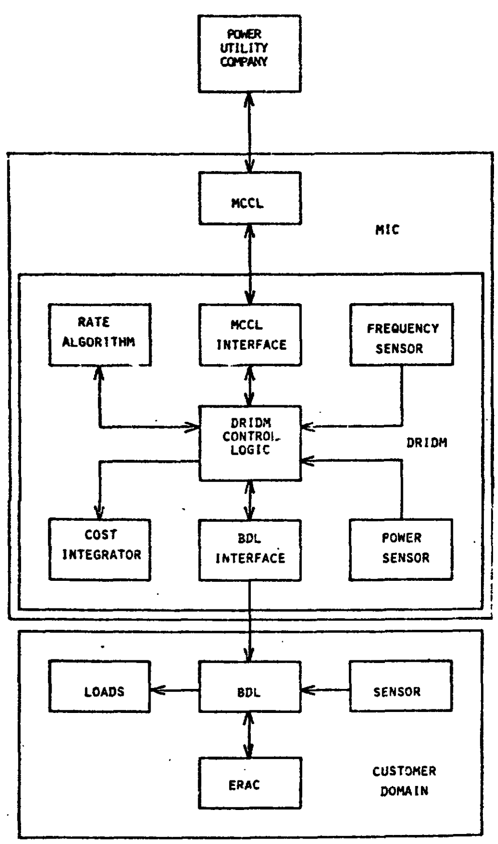

Fig. 1 Customer Control and Communication System

The Marketing Interface to Customer (MIC) is the communications link which transfers information between the power company (Marketing System) and the customer. It consists of several functions. The Market to Customer Communications Link (MCCL) is the actual information transfer path. In addition, MIC contains a Dynamic Rate Integrating Demand Monitor, which serves to replace today's watthour meter.

The Dynamic Rate Integrating Demand Monitor (DRIDM) is the watthour meter of this system, although its functions are more complex than those of today's meters. This element has within it several functions. The power level sensor is a transducer which detects load level. The cost integrator accepts information from the power level sensor and price information from the MCCL. It uses these two pieces of information to generate customer cost, which it integrates and stores. The frequency sensor provides information to the customer's energy controller (ERAC) to implement frequency adaptive control (FAPER) and a load responsiveness sensor detects if and to what extent FAPER is working.

The intra-Building Data Link (BDL) is the function that connects all of the customers' hardware together and, in addition, connects to the MIC. It provides the necessary paths for information flow.

The Energy Resource Allocation Controller (ERAC) is a function which schedules the customer's loads. It accepts data on price and system frequency from MIC and issues commands to energy-using devices via BDL.

With that brief description of the system, it would be worthwhile to discuss each of the important elements of the system.

The MCCL is a data communication system employed to interconnect the electrical power supplies (Marketing System) to its customers. Several such systems are already under development and testing [3]. Any of three types of communication media are employed in systems presently under development. These are power line carrier, telephone wires, and radio. Ultimately, the possibility of optical fiber must be added. The specific selection among these possibilities is not important for this discussion. The primary motivation for power company-to-customer communications systems has been automatic meter polling. Technical considerations in no way limit the use of such systems to this domain. For all applications considered here data rates would not have to be very high because message traffic would be sparse and message lengths would be short. Further, much information transferred, such as price information, would be broadcast, with all MIC's on the system receiving at once.

Because two-way communications systems are proving to be feasible, it will not be necessary to say much more about this part of the system.

The Dynamic Rate Integrating Demand Monitor may be thought of as a very "smart" electronic power meter with communications interfacing. This element will be required to interface with the MCCL and the customer communications system (BDL). It will incorporate some fairly sophisticated computational abilities.

DRIDM is an instrument that will be made economically feasible by microelectronic technology. The computational facilities within this instrument would be contained on one or a very few chips comparable with today's microprocessors. Thus these devices may be mass-produced at very low cost per unit. To accommodate for differences in installations, process instructions for DRIDM may be contained in Read-Only memory.

In its normal operating mode DRIDM will accept and store a datum representing price from MCCL. At frequent intervals it will measure power usage, multiply that by the price, and then add the resulting number to the register in which cost is accumulating. At less frequent intervals DRIDM will receive polling inquiries from the Marketing System, through MCCL. These inquiries will be about the price currently stored (to verify that DRIDM has, indeed, the right price) and about the cost stored in the accumulator.

DRIDM will also contain an element to measure system frequency. This information will be passed on through BDL to ERAC, to implement frequency dependent (FAPER) control. DRIDM may also contain elements to reinforce the use of frequency dependent control. For example, it would be possible to measure load frequency responsiveness by observing load changes coincident with changes in the frequency signal. A rate differential could be offered by the Marketing System for the frequency responsive part of a customer's load. Alternatively, frequency dependent loads could be rewarded by having a rate differential dependent on system frequency. Loads that accept energy at high system frequency, but not low system frequency, would pay less, because the rate would be a declining function of frequency. Development work will be required to find appropriate ways of building reliable and economical power and frequency transducers for this application.

ERAC would be a customer-owned function, which might take any of many forms. For large energy using industries ERAC might be a very sophisticated computer, while for residential users it might be nothing more than a frequency-dependent controller and a wall display indicating instantaneous price.

For users with enough energy load to justify the cost, ERAC would accept the spot price from MIC, and status messages from elements such as thermostats, level sensors, etc. It might also accept predictions of price, weather, etc. ERAC would then schedule energy loads in such a way as to minimize the total energy bill. This behavior will, of course, tend to even out total system load.

In time, it is reasonable to expect that small, inexpensive ERAC's will come onto the market. These would be built using microelectronic technology, and might become quite inexpensive as have, say, electronic games and toys. Thus it is reasonable to expect that a large fraction of system loads would eventually come under ERAC control.

The Building Data Link is an element used to transfer information between the DRIDM, the customer's ERAC, and energy-using devices on the customer's system. It is possible, in principle, for the customer data transfer functions to be handled by a hard-wired system. That is, twisted pairs of wires might be connected between the MIC and the ERAC, and from the ERAC to each load. This, while it would work, would not be a very good solution, for it would imply a custom installation for each customer. In addition, changes to the system would be difficult and expensive to implement.

A better solution to the communications problem would be to formulate a standard for a BDL. This data link might employ a single data bus, to which each of the elements to be involved in information exchange would be connected. The BDL would, most likely, employ a packet switching scheme for addressing messages, as opposed to line or path switching.

The use of a standard Building Data Link offers several advantages. A standard would imply that data link interfaces could be mass-produced. The BDL interface could be produced as a single chip, and would therefore be quite inexpensive. Installation and system expansion would be made quite easy and inexpensive: any device with data communications requirements would be built to "plug in" to the data bus.

In a very real sense the existence of a BDL standard would be very much like the existence of a standard for power for small energy-using devices. Most energy-using consumer and commercial goods, from electric typewriters to washing machines, employ a common standard for electric power. The standard specifies the voltage, frequency, and connector to be used. Because such a standard exists the installation of most electrical devices is accomplished by simply plugging into a power socket. It is hard to imagine a situation in which such a standard did not exist, and in which different appliances were to require different voltage (or worse, frequency).

It should be noted that the BDL standard proposed here would be useful for much more than implementing Homeostatic Control. All sorts of equipment, including devices that are not energy-using, can be controlled through such a link. One can envision the rapid and easy implementation of systems such as security systems (fire and burglar alarms) with distributed elements, control of lighting, or even process control. A standard communications link system, if it were to become accepted, would result in data buses being installed in many locations, with a very wide range of uses. Thus BDL would cause Homeostatic Control to be synergistic with many other possible uses.

Modes of Use

Now that the basic elements of the system have been described, it is appropriate to examine some of the ways in which it might function.

To implement the customer's end part of Homeostatic Control, the system has two functions. One of these is to implement Frequency Adaptive (FAPER) control. In the most likely configuration, one element of the DRIDM would be a frequency sensing element. This would generate a signal (a binary number) representative of frequency deviation from nominal. This number would be transferred, through BDL, to the energy rescheduler (ERAC). ERAC would have available to it other pieces of information about the energy load processes themselves (such as temperatures, levels, etc.). With this information ERAC may be used to implement a FAPER control law of virtually arbitrary form.

An alternative implementation of the FAPER control law would be to install a separate FAPER controller on each energy load. This implementation might be less desireable because it would require a frequency measuring element at each load. A third possibility would be to employ a single frequency measuring device which would be part of DRIDM, but a separate FAPER controller on each energy load. The only information transferred through BDL would be the frequency deviation.

An important function of DRIDM would be to provide positive motivation for the customer to install FAPER control. This could be done by measuring responsiveness of the load to changes in frequency. If the frequency deviation signal is generated by DRIDM itself, a simple correlation of load variation with frequency variation would be straightforward to implement. The average frequency responsive load, passed on to the cost integrator, could be billed with a favorable price differential.

Alternatively, the price charged for power could be made frequency dependent, with a negative price differential for positive frequency deviation. This, too, would reward frequency responsive loads. The implementation of this would be simply to feed the frequency deviation to the cost integrator logic, which would add or subtract a differential from the posted spot price.

The attractiveness of these schemes, particularly of the second, depends somewhat on what type of power level sensor is used, and on how often use is recorded.

The frequency dependent price would be useable only if energy use is recorded frequently enough to catch system swings.

The responsiveness of this system to spot price variations will vary according to the customer. Spot price will be "posted" by the Marketing System through MCCL, thence through BDL to ERAC or to a display. It is likely that, at least at first, few small customers will have an ERAC with price responsiveness characteristics. Many will have wall displays and perhaps annunciators set to alarm at a certain price level. On the other hand, large customers will employ sophisticated control systems which will employ, in addition to the posted spot price, process sensor data and predictions of spot price, weather, etc. The purpose of these controllers will be to minimize total cost by rescheduling loads from time of high spot price to times of low spot price.

As an example of this rescheduling function, consider some energy-using process that puts its output into storage, from which point another process uses the output. This might be, for example, a water pump discharging into an elevated tank. If the storage residence time is fairly long, the controller can operate the process only when power is relatively cheap. The word "relatively" is important here, for fluctuations in, say, the weather will affect the variation in price. The controller might have several set points associating inventory with price. The lower the inventory, the higher the price below which the controller will operate the process. For some processes it might be necessary or desirable to employ information from the weather forecast in order to operate the process at near minimum price.

All of this will, of course, serve to even out fluctuations of system load, because many intermittently operating processes will be rescheduled to take advantage of cheap rates. Perhaps more important, it will result in substantial reduction of system peak load, because many loads will avoid the time of peak prices.

Under Homeostatic Control, the communications link (MCCL) has several functions. In the "uplink" direction it posts the spot price periodically. In the "downlink" direction it may be asked to repeat the spot price, to verify that it has it correctly. A communications system with such capabilities may also be used for automatic meter reading: an uplink polling signal and a downlink cost message. The communications link might conceivably be used for yet other functions. For example, it might be used to transmit future price predictions, to help customers plan their energy usage. Other signals, including perhaps load control signals or emergency warnings might be transmitted through MCCL also.

An important feature of the Marketing System Interface to Customer (MIC) is the one-way nature of information flow. The Marketing System can pass information to the customer through MIC. It receives information only from the metering elements (DRIDM) within the MIC interface. No information owned by the customer is accessible through this system. Thus this type of control system does not threaten customer privacy.

While this discussion has been cast largely in terms of Homeostatic Control, it is important to see that the system described here might be used for purposes that are not explicitly part of that control strategy. One example would be a pricing scheme more like what is presently in use, with fixed (or time-of-day) rates and a peak demand charge (which might be time varying). Under such a scheme the MCCL would be used for automatic meter reading, perhaps for time-of-day rate rescheduling and for announcing modifications to the demand charge structure.

Under a scheme such as this, the function of the energy rescheduler (ERAC) would be to coordinate various loads to operate at low rate times and to smooth out total load. The BDL would function in the same way under this system as under Homeostatic Control.

The system described here could be used to implement a load shedding scheme which might be termed "Microshedding". Under this scheme, a relatively large number of loads could be designated as interruptible. Of course this is done now, but only with few, rather large loads. With the appropriate communications and control structure a much larger fraction of total system load could be made interruptible, without affecting the continuity of service to important loads. With such a scheme a utility could shed a substantial fraction of its total load without totally disrupting any customers.

The flow of information would be like this: The utility would send a signal requesting a load reduction through the MCCL. Passed to ERAC, the load reduction request would prompt ERAC to turn off some loads. The load reduction request could be for any level of load curtailment. It is even conceivable that different customers could buy power at different priority levels, so that lower priority customers, who would pay less for their power, would have a greater risk of curtailment and/or a larger fractional load reduction in an emergency. The role of the DRIDM in this scheme would be to monitor the load curtailment to verify that it did, in fact, take place. Enforcement of the load reduction could be through one of several mechanisms: For example, a punitively high rate could be charged for power drawn above the curtailment limit. Alternatively, a customer who did not meet the load reduction request might be turned off completely. This would be accomplished through information interchange between DRIDM and the utility, and a service entry breaker.

The communications and control system described here may be used to help control the injection of customer generated power into the power system. This power might come from alternate energy sources (windmills, solar collectors or small waterwheels) or from cogeneration. In the future the power system will be expected to purchase power from customers who have it to sell. The rate that the system will pay will be less than the selling price to other customers, so the DRIDM must be able to remember a buying, as well as a selling, rate. For those customers with generation capability both a buying and a selling price must be posted. This should be no problem with the system proposed here. The communications capability of this system will even allow the utility to exercise some control over the generating units, through direct control or through price. It is possible, for example, that the utility might control reactive power through field excitation, either directly or by paying for VAR's.

CONCLUSION

There are many pressures which will tend to force changes in the operation of power systems in the future. The increasing cost of fuels and difficulty of building generation facilities will make load levelling more and more attractive. In addition, increasing fuel cost will make alternative sources and co-generation more important. All of this will produce pressures to make the price charged for electricity reflect more accurately its true economic cost. Rates that are variable in time are necessary to do this correctly.

The tools required to implement variable pricing, frequency adaptive controls and other advanced concepts, exist today and will become more economical in the future. Very sophisticated controllers may, through the use of microelectronics, be made very inexpensively.

One possible configuration of hardware functions has been described here. It meets the requirements of Homeostatic Control and can satisfy other requirements as well. Clearly, however, other arrangements of functions are possible, and it is not intended that this arrangement pre-emp all other possibilities.

Several different hardware functions are required to implement the system described here. Of these functions, the utility-to-customer data link (MCCL) is already under development. Various power-energy reschedulers are already in place in hard-wired environmental control systems for large building, so it is not difficult to anticipate that development of such devices will be straightforward.

Further work will be required to develop two essential pieces of equipment. One of these is the Dynamic Rate Integrating Demand Monitor, which has several important functions. In particular, the development of an inexpensive, accurate frequency measuring device will be an interesting challenge.

The most difficult problem here is the definition of a standard for the Building Data Link (BDL). The difficulty arises not from the technical requirements, which are not terribly stringent, nor the anticipated price, which will be quite low, but from the necessity to get many people and organizations to agree. In order to be useful, this data link standard must be observed by many different manufacturers, many of them making competing equipment.

The stakes in this development are very high. The development of an effective, well-observed standard would result in large economies of scale. The BDL interface would become very inexpensive. Manufacturers of many types of equipment, including equipment that is not energy-using, would build apparatus that would transfer information through the bus. Thus the data link itself would become common, making the convenience of implementation of sophisticated energy controls high. On the other hand, if a standard can not be agreed upon, the implementation of controls for energy loads will be difficult and awkward.

An immediate goal of the electrical power industry and society as a whole must be to improve the manner in which we use available energy generation and distribution resources to conserve energy, enhance capital investment return, increase reliability, and augment the quality of the customer product. Only by greatly increasing the resolution of control and making it more responsive to the realities of the energy marketplace can these goals be achieved. An essential element to the realization of these goals is the utilization of a distributed interactive control system, an example of which has been provided by this paper.

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3.4 PHYSICAL/ECONOMIC ANALYSIS OF INDUSTRIAL DEMAND

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ABSTRACT

Physically based models of the demand for electricity of industrial customers provide insight into what types of production schedules are feasible and how rescheduling will change the load shape. Physical models can be combined with economic analysis to analyze a variety of issues related to electric rates, load management, the cost of outages, etc. For example, the reduction in the monthly electric cost due to rescheduling of a production process can be compared with the extra cost incurred due to wage differentials. One key tool is shown to be the comparison of the kW per person of a production process with the "breakeven kW per person" of the firm as determined by the rate and firm's usage pattern. Two electric rates are explicitly analyzed as examples; a declining block rate and a time of day rate.

1. INTRODUCTION

The need for physically based models for electric demand is becoming crucial as the utility capacity planning, load forecasting, and rate setting problems become ever more complex. Physically based models for industrial demand can provide some answers to questions concerning changes in production schedule, effects of new technology, e.g. solar power, effects of new rates, e.g. time of day pricing, load management and the cost of outages (value of reliability). An overall framework for physically based load models was discussed in [1] and [2] in general terms. This paper summarizes some of the results of a study of seven industrial customers of New England Electric System [3]. See Table 1 for a brief description of the seven companies. The modeling of each individual industrial customer consists of two general steps. Step 1 is to develop a physically based load model. This was described in [4]. This paper addresses Step 2 which uses the results from Step 1 and makes various types of economic analyses.

One specific issue analyzed in this paper is the effect c electric rates on industrial customers. A given industrial customer might respond to a rate change in various ways such as:

- No change in electric power usage
- Reschedule plant operation to change electric power use patterns keeping total plant production constant
- Change total plant production (in extreme case, close plant)
- Install new equipment.

To be presented at the IEEE Power Engineering Society, 1979 Summer Meeting, Vancouver, B.C. July, 1979

The analysis done in this paper assumes the rate change is not enough to effect the total production level of the industrial customer. Issues associated with a customer installing new production equipment in response to rate changes are not considered. The key issues considered are whether an industrial customer will reschedule operation and if so, how?

The physical/economic analysis described in this paper does not yield direct predictions of the changes in load due to a change in one of the exogenous variable, e.g. electric rate, labor cost, etc. Rather, the method provides a way to analyze an industrial firm and identify those possible alternatives that are clearly uneconomical and those that are possibly economical. This type of insight is helpful to regulatory agencies, utility rate designers, and planners in the evaluation of the possible effect on utility's load shape and peak demand due to a change in an exogenous variable. The ideas can also be of direct value to the managers of industrial processes as the ideas are developed from their point of view.

2. REVIEW OF PHYSICAL LOAD MODEL

As described in the companion paper [4], physical load models for individual industrial customers consist of "stochastic elements" and "storage flow constraints". These general models can be employed in various ways. Only those aspects pertaining to the particular applications of this paper are reviewed here.

In [4] the stochastic modeling is done in continuous time and then converted to discrete time. Here only discrete time, n = 1,2,... is used where the time increment is 15 minutes. Define as in [4]

$P_j(n)$: power demand (15 minute average) at time n of jth process (equipment) of customer

$$P_T(n) = \sum_j P_j(n)\text{: total demand of customer} \quad (1)$$

$$P_j(n) = X_j\, r_j\, u_j(n) \quad (2)$$

X_j: installed kW capacity of jth process (equipment)

r_j: percentage of kW capacity when process (equipment) is on; $0 \leq r_j \leq 1$

$u_j(n)$: utilization factor; $0 \leq u_j(n) \leq 1$

The utilization factor is a stochastic (random) process which in [4] is modeled as a 2 state Markov process. One key statistical parameter of this process is

a_j: fraction of time process j is on during a particular work shift

$$E[u_j(n)] = a_j$$

and the mean value of demand is given by

$$E\{P_T(n)\} = \sum_j E\{P_j(n)\} = \sum_j X_j\, r_j\, a_j \quad (3)$$

Define

D = maximum $P_T(n)$: Peak demand (15 minute average) of customer for one month (assume occurs sometime during first shift)

ΔD_j: Change in peak demand if customer reschedules the operation of the jth process (equipment) from 1st shift to either 2nd or 3rd shift.

Since $P_T(n)$ is a random process, ΔD_j is a random variable. However when the total plant demand is the sum of many small equipment demands, analysis of the statistical properties of ΔD_j shows that a good approximation is (see [3,4]),

$$\Delta D_j \approx = X_j \; r_j \; a_j \tag{4}$$

This is very important as it says the stochastic variation can be ignored and only mean values are needed to determine the change in monthly peak demand due to rescheduling. The same conclusions also applies to monthly electrical energy consumption.

The storage flow aspects of the physical model view the overall industrial process of a particular customer as a series of "material storages" connected by "processing flows" where the processing flows involve the use of equipment which consumes electricity. The constraints imposed by the size of the storages and the maximum allowable process flows place restrictions on the types of rescheduling the customer can do (if the total production is to be held constant).

3. ANALYSIS OF ELECTRIC RATE STRUCTURES

Two types of electric rate structures are used in this analysis.

H rate: Reducing block type rate

X rate: Time of day type rate

The numerical values used in the analysis are "realistic" but are to be viewed as only examples.

The monthly charge under H rate is:

$$MCH(\varepsilon,D) = f_d(D) + f_e(\varepsilon,D) + \text{fuel adj.}$$

where

$MCH(\varepsilon,D)$ = monthly charge (\$/month)

$f_d(D)$ = monthly demand charge (\$/month)

$f_e(\varepsilon,D)$ = monthly energy charge (\$/month)

ε = total energy usage (KWH/month)

D = maximum of 15 minute average demand (KW)

$MCH(\varepsilon,D)$ is a piecewise linear function which can be expressed as:

$$MCH(\varepsilon_o,D_o) = 510 + \left[\frac{\partial MCH(\varepsilon,D)}{\partial D}\bigg|_{\varepsilon_o,D_o}\right] D_o + \left[\frac{\partial MCH(\varepsilon,D)}{\partial \varepsilon}\bigg|_{\varepsilon_o,D_o}\right] \varepsilon_o + \text{fuel adj.} \tag{6}$$

where

$$\frac{\partial MCH(\varepsilon,D)}{\partial D}\bigg|_{\varepsilon_o,D_o} =$$

1.54 \$/kW	$\varepsilon_o/D_o < 200$ hour
1.76	$200 < \varepsilon_o/D_o < 300$
3.14	$300 < \varepsilon_o/D_o < 400$
3.54	$400 < \varepsilon_o/D_o < 500$
3.79	$500 < \varepsilon_o/D_o$

$$\frac{\partial MCH(\varepsilon,D)}{\partial \varepsilon}\bigg|_{\varepsilon_o,D_o} =$$

2.547 ¢/kWH	$0 < \varepsilon_o < 50{,}000$
2.247	$50{,}000 < \varepsilon_o < 100{,}000$
1.937	$100{,}000 < \varepsilon_o < 200\ D_o$
1.827	$200 < \varepsilon_o/D_o < 300$
1.367	$300 < \varepsilon_o/D_o < 400$
1.267	$400 < \varepsilon_o/D_o < 500$
1.217	$500 < \varepsilon_o/D_o$

The monthly charge under X rate is

$$MCX(\varepsilon_1,\varepsilon_2,D) = 100 + \alpha D + 0.01517\ \varepsilon_1 + 0.0027\ \varepsilon_2 + \text{fuel adj.} \tag{7}$$

where

$MCX(\varepsilon_1,\varepsilon_2,D)$ = monthly charge (\$/month)

ε_1 = energy usage during peak hours (kWH/month)

ε_2 = energy usage during off-peak hours (kWH/month)

$\varepsilon = \varepsilon_1 + \varepsilon_2$

Peak hours are defined as from 8 a.m. to 9 p.m. of all working days and the remaining hours are off peak. α is a coefficient for demand charge and has values of 6.50 \$/kW for summer and 4.08 \$/kW for winter. Summer months are defined as the four months from June to September and the rest of the months are defined as winter. Note that

$$\frac{\partial MCX}{\partial D} = \alpha_{\text{seasonal}}(\$/\text{kW})$$

$$\frac{\partial MCX}{\partial \varepsilon_1} = 0.01517\ (\$/\text{kWH})$$

$$\frac{\partial MCX}{\partial \varepsilon_2} = 0.0027\ (\$/\text{kWH})$$

Let S_{xh} be the difference between the monthly charges under the two rates

$$S_{xh} = MCH(\varepsilon,D) - MCX(\varepsilon_1,\varepsilon_2,D) \tag{9}$$

After substitution, Eq. 9 becomes

$$y = \frac{S_{xh} - 410}{D} = \left(\frac{\partial MCH}{\partial D} - \alpha\right) + \frac{1}{(1+\beta)}\left[\left(\frac{\partial MCH}{\partial \varepsilon} - 0.01517\right)\beta + \left(\frac{\partial MCH}{\partial \varepsilon} - 0.00277\right)\right]\left(\frac{\varepsilon}{D}\right) \tag{10}$$

$\beta = \varepsilon_1/\varepsilon_2$

Let y_S, y_W, y_a represent y during summer, winter and yearly average. Figure 1 shows y_a as a function of ε/D

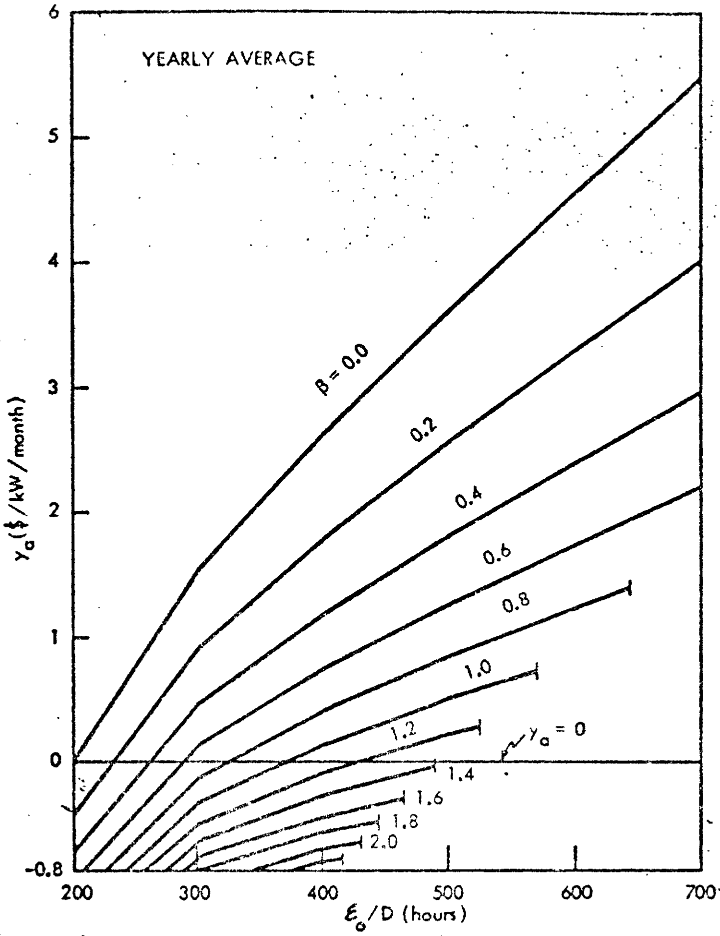

Figure 1 Comparison of H and X Rates (assuming no change in schedule)

with β as a parameter. The curves for y_a and y_S are similar in shape but numerically quite different (see [3]). Such curves provide a convenient summary of the difference between the two rates. It is easy to determine whether a customer with a given D, ε_1, and ε_2 will pay more or less under X or H rate. If the range of D, ε_1, and ε_2 for all customers is available, such curves provides a useful vehicle for comparing the effect of switching from H to X rate (assuming the customers' usage patterns do not change).

This section has shown, by example, that analysis and comparison of different rates follows naturally simply by expressing them as well defined mathematical functions. The approach is obviously equally applicable to many other types of rates.

4. EFFECT OF ELECTRICAL AND LABOR COST ON PRODUCTION SCHEDULES

Knowledge of the partial derivatives of the monthly charge such as

$$\frac{\partial MCH}{\partial D}, \quad \frac{\partial MCH}{\partial \varepsilon}, \text{ etc.}$$

are useful to a manager who is trying to save money by balancing possible savings from rescheduling due to reduction in electric cost with the increase in labor cost.

For simplicity, consider a customer with all operations presently scheduled for first shift. Then the effect of rescheduling the jth process (equipment) to 2nd or 3rd shift can be analyzed as follows (assuming total energy consumption is not changed). Define

$$\Delta TMC_j = \Delta MC_j + \Delta OMC_j \tag{11}$$

ΔTMC_j: change in total costs due to rescheduling

ΔMC_j : change in monthly charge for electricity

ΔOMC_j: change in other operating costs

The analysis considers only salary cost effects to keep the example simple. Thus

$$\Delta OMC_j = (\Delta R_j)(HW_j)(NP_j) \tag{12}$$

NP_j: number of persons needed to operate jth process (equipment)

HW_j: working hours/person/month

ΔR_j: change in hour salary rate from first shift to second or third shift.

However other costs such as extra lighting and heating can also be included in a straightforward fashion to ΔOMC.

Now for H rate

$$\Delta MC_j = \int_{D_o}^{D_o+\Delta D_j} \frac{\partial MCH(\varepsilon,D)}{\partial D}\, dD \tag{13}$$

where D_o is the original peak demand and $D_o+\Delta D_j$ is the new peak demand. If the change is not large, a reasonable approximation is

$$\Delta MC_j = \Delta D_j \frac{\partial MCH(\varepsilon,D)}{\partial D} \tag{14}$$

Combining (4), (11), (12) and (14) yields

$$\Delta TMC_j = - X_j\, r_j\, a_j \frac{\partial MCH(\varepsilon,D)}{\partial D} + (\Delta R_j)\,(HW_j)\,(NP_j) \tag{15}$$

Define

$$A_j = \frac{X_j\, r_j\, a_j}{NP_j} \text{ (kW/person)} \tag{16}$$

$$A_j^e = \frac{\Delta R_j \times HW_j}{\frac{\partial MCH}{\partial D}} \text{ (kW/person)}$$

$$= \frac{\text{Additional labor cost/person (\$/person)}}{\text{Saving per kW reduction in demand (\$/kW)}}$$

A_j^e is the "break-even kW of electrical demand per person". Then it follows that

$$\boxed{\begin{array}{c}\text{There is a monthly saving only if}\\ A_j > A_j^e\end{array}} \tag{17}$$

The analysis, leading to (17) was done for H rate. For X rate the only change is that $\partial MCH/\partial D$ is replaced by

$$\frac{\partial MCH}{\partial D} + \left(\frac{\partial MCX}{\partial \varepsilon_1} - \frac{\partial MCX}{\partial \varepsilon_2}\right) NHI$$

where NHI is the number of hours involved per month that change from peak hour operation to off-peak hour operation and

$$\left(\frac{\partial MCX}{\partial \varepsilon_1} - \frac{\partial MCX}{\partial \varepsilon_2}\right) NHI$$

is the dollar savings per month derived from energy rate differential due to rescheduling of a 1 kW constant expected power demand from the first shift to the second or third shift.

Condition (17) provides a tool a manager of a firm can use to decide whether or not to reschedule any operations. One possible procedure the manager might use is as follows:

Step 1 - Find process (equipment) j such that

$$A_j > A_j^e$$

Step 2 - For processes (equipment) j which pass Step 1, find those whose rescheduling will not violate any flow-storage constraints

Step 3 - Do detailed cost analysis on those processes (equipments) j which pass Step 2

Our experience with the seven firms studied and the numerical values used showed that only a few processes j survived Steps 1 and 2.

Table 2 shows some of the numerical values for the larger A_j for the seven firms of Table 1. Of course many processes have smaller values (a secretaries' A_j is much less than unity). Table 3 shows the parameters that are used and the resulting break-even A_j^e under both H and X. Figure 2 shows graphs of how the break-even A_j^e for X rate vary as functions of season, type of rescheduling and wage differential. All these numbers are given here only as examples to illustrate the type of results to be expected. No attempt should be made to draw any explicit, general conclusions from them.

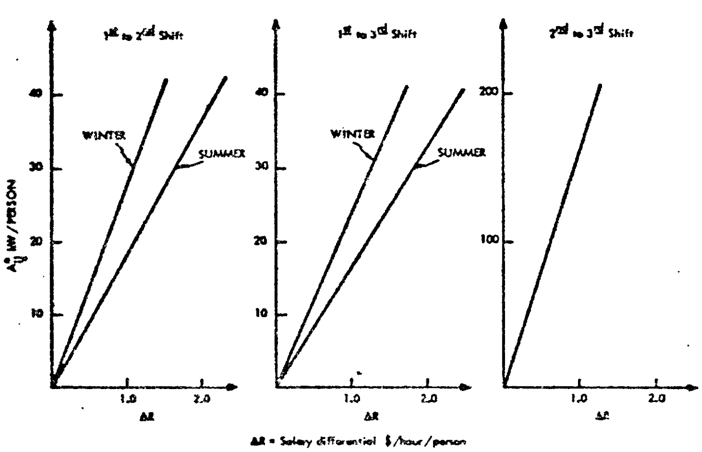

Figure 2 Behavior of X Rate Break-even kW/Person A_j^e

5. CUSTOMER PEAK DEMAND VS. UTILITY PEAK DEMAND

When considering load management issues it is important to emphasize that reduction in an individual industrial customer's peak demand does not necessarily reduce the peak demand the utility has to meet. Assume the utility's total demand (residential, commercial and industrial) is such that there is a "two hour peak period". Following the arguments that lead to the use of Eq. 4 for a single industrial customer, the utility should usually try to influence each individual industrial customer to reschedule their operation to reduce the total KWH they consume during this two hour period rather than to reduce their peak demand (15 minute average) during this period unless one customer completely dominates the total demand. The installation of special "load control" systems by the customers in order to reduce their 15 minute peak demands is often not effective load management from the utility's point of view. It reduces the individual customer's demand charge but may have very little effect relative to reducing the peak demand the utility must meet.

6. RATE DESIGN

Suppose a utility wants to design a time of day rate for industrial customers which will reduce the utility's peak demand. Assume the A_j (kW/person) and flow storage constraint models are available for all industrial customers. Then rate design could conceptually proceed by trying to find a time of day rate with breakeven A_j^e that are "substantially" less than a "reasonable percentage" of the A_j which are not effected by flow storage constraints. Graphs such as Figure 2 can give a rate designer a feel for the possible effect of hypothesized rates.

If all the A_j are less than the A_j^e, it is clear no production scheduling changes will be made. However the analysis discussed in this paper provides no mechanism for predicting how large $A_j - A_j^e$ has to be to provide enough financial incentive for a manager of an industrial firm to "go to the trouble" of rescheduling. Conceptually such a mechanism could be developed and added to the physical load model, A_j, A_j^e concepts but it is not discussed further here.

Often it is desired to constrain new rate designs so that the total utility revenues are not changed. The ideas of Section 3 can be used to handle this constraint.

7. SOCIAL IMPLICATIONS OF PRODUCTION RESCHEDULING

Suppose X kW of demand can be economically rescheduled from first to third shift. Let NPC be the number of people that are rescheduled from the first to the third shift. Let $A_j^{e\ min}$ be the smallest break-even A_j^e that can be found for all the customers. Then

$$NPC \leq \frac{X}{A_j^{e\ min}}$$

If X = 100 MW, $A_j^{e\ min}$ = 50 kW/person, then NPC < 2000 people. Thus the number of people effected will usually be relatively small if rescheduling is done economically because only workers with high power usage (i.e. large kW/person) are rescheduled.

8. NET DEMAND CHANGE FROM PRODUCTION RESCHEDULING

Assume the industrial customers have rescheduled NPC people from first to third shift. This will reduce industrial demand during the first shift but many of these people will go home and cause an increase in residential demand. This effect is not important provided the rescheduling is done on economic grounds as the industrial breakeven A_j^e will usually be much greater than the residential kW/person usage. If however, rescheduling is done by some government edict and economics are ignored, it is possible that a sizeable percentage of the reduction in the industrial

"Name" of Company	Monthly Peak Demand (kW)	Monthly Energy Usage (kWHx10^3)	Product
Small Plastics	850	410	Extrusion plastic molding
Brush	3400	1500	Extrusion plastic molding
Abrasive	4300	1800	Abrasive
Soap	3500	1250	Powder and bar soap
Foundry	1600	1000	Sluice gate and industrial rolls
Printing	810	320	Telephone directories
Small Customer Product	1500	350	Pocket and kitchen knives

Table 1 Brief Description of the Seven Industrial Companies

	A_j (kW/person)	Present Schedule of Operation
Furnace for melting steel	1700	3rd shift
Machine Shop	2 to 20	1st shift or multiple shift
Printing Press	20	
Waste Baling	60	
Plastics Extrusion Molding	7 to 150	Three shifts/day, five days/week intermittently
Tower (synthetic soap process)	200	

Table 2 Examples of A_j

Company	ΔR $/hr-person		A_j^e (kW/person) X Rate				H Rate	
	1st-2nd shift	1st-3rd shift	1st-2nd winter	1st-2nd summer	1st-3rd winter	1st-3rd summer	1st to 3rd	$\frac{\partial MCH}{\partial D}$ $/kWH
Foundry	0.75	1.00	27	18	28	20	46	3.79
Small Customer Products	0.50	0.50	18	12	14	10	50	1.76
Printing	0.45	0.60	16	11	17	12	34	3.14
Small Plastics	0.15	0.25	6	4	7	5	12	3.54
Brush	0.15	0.25	6	4	7	5	12	3.54
Soap	0.3	0.38	11	8	11	8	21	3.14
Abrasive	0.5	0.5	18	12	14	10	25	3.54

Table 3 Break-even kW/person A_j^e for X and H Rates

sector demand could be off set by increases in the residential sector.

9. ELECTRIC POWER "SUPPLY CURVES" OF A MANUFACTURING FIRM

In the field of microeconomics, the supply curve is used to express the quantity of certain products available for sale as a function of the price ($/quantity). The supply curves to be discussed here express the quantity (kW) of electric power demand a particular industrial customer might be willing to "sell back" to the utility at a given "price" ($/kW). The utility would like its customers to reduce their usage of power during the peak demand hours; for this, the utility is willing to pay the manufacturing firm a "price". "Selling back" refers to the fact that the customer will reduce its electric power usage by a certain amount of kW during certain hours of the day and time of year. Define

CP_j: cost to the customer of rescheduling j^{th} equipment ($/kW)

Then assuming storage flow constraints are not violated,

$$CP_j = \frac{\Delta R_j \; HW_j}{A_j} \quad \$/kW$$

where as before, ΔR_j in the salary differential and HW_j is the number of hours effected. Then the "supply curve" of a particular customer is defined as a plot of CP_j vs. kW when the CP_j are ordered in terms of increasing $/kW costs.

As an example, consider a utility with flat daily summer peaks which occur during the first shift and sharp daily winter peaks around 7:00 a.m. The utility's daily peak can be reduced in the summer if an industrial customer reschedules from first shift to third shift and in the winter if the customer delays its second shifts from, say, 4:00 pm to midnight to 9:00 pm to 5:00 am. Figure 3 shows supply curves for "Printing Company". The supply curve for winter is lower because the number of hours involved is 5 hours per day per person as compared to 8 hour/day/person for summer and because the wage differential is lower between second and third shift.

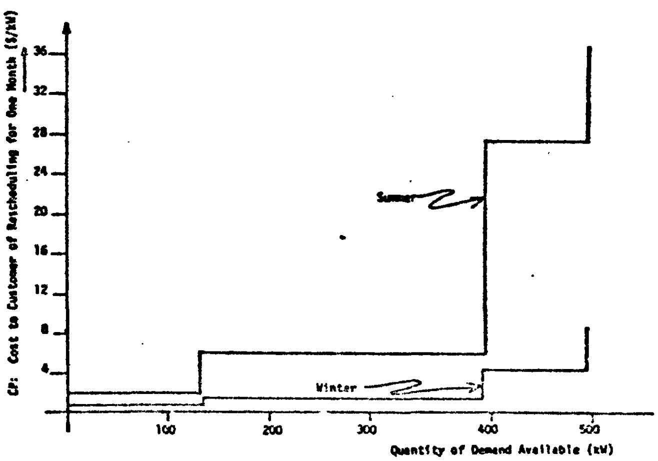

Fig. 3 Electricity Supply Curve

Figure 3 is only an example for one customer and the numerical values will vary widely between customers. However the "nonlinear, sharply rising" nature of the curve is to be expected for most customers. A utility can often buy a few kW cheaply but the costs rise rapidly when a lot of kW is to be bought.

10. VALUE OF RELIABILITY

There is an ever growing desire to associate numerical values to the worth of having a reliable power system. One approach is to evaluate the cost of power curtailments caused by a capacity shortage (generation and/or transmission). It is reasonable to expect that industrial customers will be effected first and asked (forced) to reduce their use of electricity during capacity shortage periods. Supply curves such as in Figure 3 can be used as aids to rate design but can be interpreted just as easily in terms of the cost to the customer of partial curtailments.

The nonlinear nature of electric supply curves such as Figure 3 emphasizes the need for extreme care when analyzing the cost of curtailments. For example, assume that the utility has to reduce its demand for 3 hours in the afternoon by curtailing the industrial sector demand by 10%. If 10% of the customers were custoff entirely, the costs could be very large. If each customer was curtailed by 10%, the costs would be much less. The least cost would result if the utility had supply curves such as Figure 3 for each customer and choose a curtailment logic that minimized the costs.

11. DATA REQUIREMENTS

The rate design, supply curve, cost of curtailment etc. studies just discussed proceed in a straightforward fashion provided all the A_j, flow storage models, etc. are available for all of the utility's industrial customers. In practice this requires a massive data collection and manipulation effort.

One conceptual way to reduce the data requirements is to try to use "sampling theory" and consider only a few "representative" customers. Unfortunately it appears that this approach will not be very effective for the industrial sector. Customers with identical SIC codes may respond completely differently to rate changes, etc. because differences in plant layout, labor availability, etc. can result in different A_j and flow storage constraints. At the present time the authors of this paper feel that data from a high percentage (over 50%) of a utility's industrial customers will be needed before really reliable analysis can be made for many of the issues of real concern.

This does not mean however, that it is always necessary to obtain complete equipment inventories and flow storage models for each customer. For many studies, it is only necessary to consider the equipment/processes with the largest A_j or those with A_j above some level. Such "partial inventories" can then be combined with measured 15 minute demand patterns to address many of the issues of concern. The research effort as summarized in [3,4] and in this paper obtained complete equipment inventories, developed complete stochastic models, and then compare these models with observed plant behavior. The success of this provides some real justification for the much easier procedure of using limited inventories of only the large A_j equipment/processes combined with recorded demand patterns.

Many utilities have "industrial representatives" who maintain close contact with individual industrial customers. The authors of this paper feel that the best way to get the needed information for industrial demand analysis is to work through these industrial representatives. They can be trained and furnished with questionnaire material which will enable them to work with the customers themselves to obtain the needed information. If it is necessary to only mail questionnaires to the industrial customers, the questionnaire must be very carefully designed to get the type of information that is really needed. In either case, the authors feel the needed data can be obtained with a reasonable (albeit non trivial) amount of effort.

12. DISCUSSION

One main point of this paper is the obvious one that in order to analyze how the industrial demand for electricity will respond (to rates, outages, etc.), it is necessary to consider the customer's point of view. Thus it is necessary to learn which of the processes (equipments) within the customer's plant:

- could be rescheduled considering constraints on plant flows and storage
- are cost effective to rescheduling

Physical flow storage models provide information on constraints. Another main point of this paper is the derivation of two key quantities for economic/cost analysis. They are:

$$A_j = \frac{\text{number of kW used by process } j}{\text{number of persons needed to run processes}}$$

which is obtained from the physical model and

A_j^e: breakeven kW/person

$$A_j^e = \frac{\text{dollar cost per person due to rescheduling}}{\text{dollar saving per kW due to rescheduling}}$$

which is obtained from the rate structure and salary (and other) costs. A final main point is that analysis is greatly expedited by representing the rates as well defined mathematical functions. Given the needed A_j and flow storage constraints for all the industrial customer, answers to many questions related to rate design, load management, and cost of curtailments can be obtained as illustrated by the application discussions of this paper.

As indicated previously a sizeable but not unreasonable effort will be required to obtain the needed data. It is reasonable therefore to ask, "Is there an easier way to try to get the same result"? In the authors' opinion the answer is no. The authors considered the use of a variety of quantities such as SIC code, kW/person for the total plant, value added/kWH for plant, peak demand to monthly energy ratio, ratio of electric costs to total operation costs, etc. However the authors could not see how to relate such quantities to the key issue of how a plant manager might respond. Without such a tie, the authors feel that such data cannot be used to address questions of the type considered in this paper.

Acknowledgements

This paper was based on work done at the Electric Power Systems Engineering Laboratory, MIT. The major financial support for this work was provided by the New England Electric System. Additional funds were obtained from the Philip Sporn Chair. Special acknowledgement must be made of the role played by the Massachusetts Electric and Narragansett Electric customer representatives and of the various employees of the seven industrial companies. This study could not have been done without their extensive help and cooperation.

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APPENDIX: ENERGY MARKET PLACE

The main text of this paper presented ideas and results of a technical nature. The following comments have been separated off as an appendix because they express personal points of view.

The work done on industrial load modeling as reported in [3] and [4] and the main text of this paper has lead the authors to believe that present day rate structures such as the H rate and time of day X rate are very artifical and restrictive. They do not allow billing that really approximates the true cost of service. They do not allow the utility to obtain the type of load management that exploits the savings in fuel and capital costs that are really possible. They do not give the customer enough motivation and or freedom to adapt his electric usage patterns to the utility's true costs and needs.

Reference [5] predicted that in the future, electric energy would be bought and sold in an open "energy market place" with "spot price rates" which vary continuously depending on demand, plant usage, etc. Such an energy market place appears to answer the problems associated with long term contracts like the H and X rate. It would be of benefit to both the utility and the customer. An energy market place could eventually include residential, commercial and industrial customers but it would probably start being implemented in the industrial sector.

The forecast in Ref. [5] of the growth of the energy market place in this country was made because the energy market place seemed (to the authors) to be the only rational way to go. The study of the seven industrial customers of the New England Electric System as discussed here provided much of the motivation for that belief.

3.5 HOMEOSTATIC CONTROL INITIAL HARDWARE DEVELOPMENT

3.5.1 Introduction

Implementation of Homeostatic Control will require moderately sophisticated hardware at the customer's site, for price responsive consumption and FAPER control. In order to obtain a preliminary understanding of the level of complexity, difficulty of design and construction, and cost of this equipment, two of the most important pieces were constructed at the M.I.T. Electric Power Systems Engineering Laboratory. The first of these is a Frequency Adaptive Power/Energy Rescheduler (FAPER); The second is an Energy Rescheduling and Allocation Computer (ERAC). A brief description of each of these devices follows.

3.5.2 ERAC

The ERAC would be used to control energy allocation at a customer's site. Its objective would be to minimize total energy cost, while satisfying the needs for electrical energy of the customer's production processes. It would operate by turning processes on or off according to process levels, current and projected price of electricity and the needs of the customer's processes. The major optimization strategy employed by the ERAC would be to operated processes relatively more intensively at times of low electricity cost, and relatively less intensively at times of high electricity cost. The type of process computer currently in use to control HVAC systems could, if properly programmed, perform this function. However, at present such systems are relatively large and expensive, and are of use primarily for only large energy consumers. In order to be useful for smaller customers, a relatively inexpensive, easily installed control system will be required. The objective in the development of the ERAC was to build a small computer which would be amenable to plug-in installation.

A second element in the ERAC project was the development of a version of a building data link (BDL). This would be important part of any energy control system in which plug-in installation is to be required, as it would provide the communications link between the ERAC and the production processes which it controls. The BDL need be designed for economical installation and effective operation. In particular, it must be flexible enough to handle a given number of devices in both input and output modes, and must provide for rapid access to each of those devices.

The ERAC which was built for this project is fairly simple in form, but is capable of sophisticated software control functions. It is a small, general purpose computer, with specialized input and output ports. The processor used is an INTEL 8085 microprocessor. This is an eight bit wide processor unit with a generalized instruction set and a four level interrupt structure. Instructions for the processor, which handles all input and output operations, as well as process control, are stored in read-only-memory. This allows a wide variety of control strategies to be used, with no changes in hardware. There is, in addition, limited random access read/write memory used for scratchpad operations.

The ERAC has three separate comunications channels. One channel is for the Building Data Link (BDL). This is a bi-directional channel, over which ERAC can talk to or listen to any of several peripheral devices which would drive actuators or would return process control information. A second communications link built into this ERAC is a serial link adapted to communicate with a teletype. This channel is used to accept price information, to simulate the signal which would, under Homeostatic Control, come from the power company. The third communications link is to the front panel of the device, which contains a ninteen key keypad and a sixteen digit LED display. These two elements, in combination, are used to establish communications with the user. The keypad is used to set price dependent setpoints and to issue commands to units to turn off or on. The display is used to show current price and usage, and to assist in data input.

A block diagram of th ERAC is shown in Figure 3.1, and a photograph of the finished device is shown in Figures 3.2 and 3.3. It should be pointed out that this is a development device, and is consequently much larger than would be a commercial product.

In operation, the keyboard/display is used to give the instrument instructions regarding price dependent process setpoints. Price information is accepted by the ERAC through the serial input port. At each interval of time, established by an internal clock, the ERAC checks all process levels through the BDL and compares these levels with setpoint levels which correspond with the currently valid price. "On" and "off" instructions are issued through the BDL.

3.5.3 FAPER

The FAPER is a device which implements a frequency dependent process control law. The device built is a stand-alone FAPER, with no external control or communications requirements. The device makes a very precise

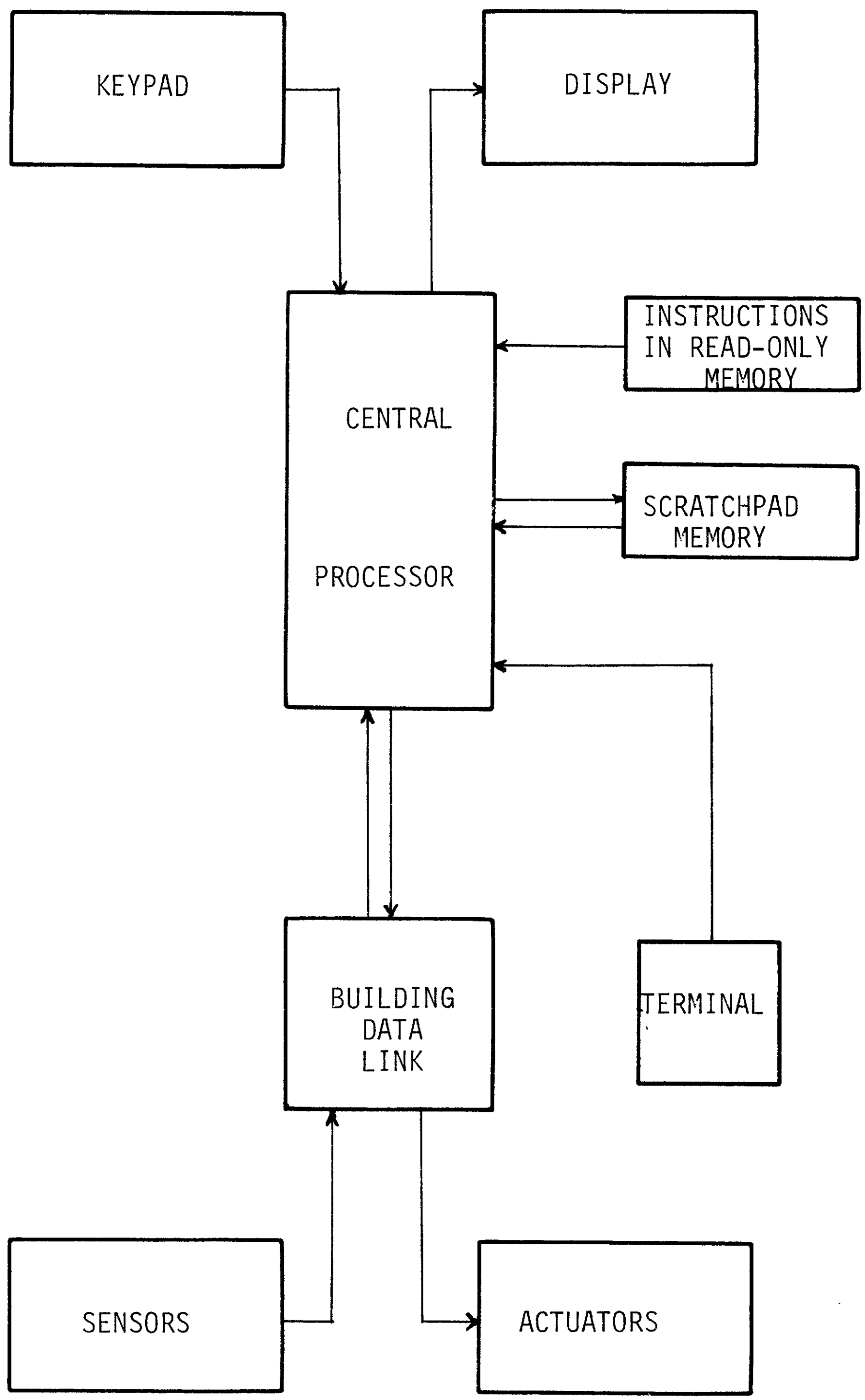

Figure 3.1:ERAC

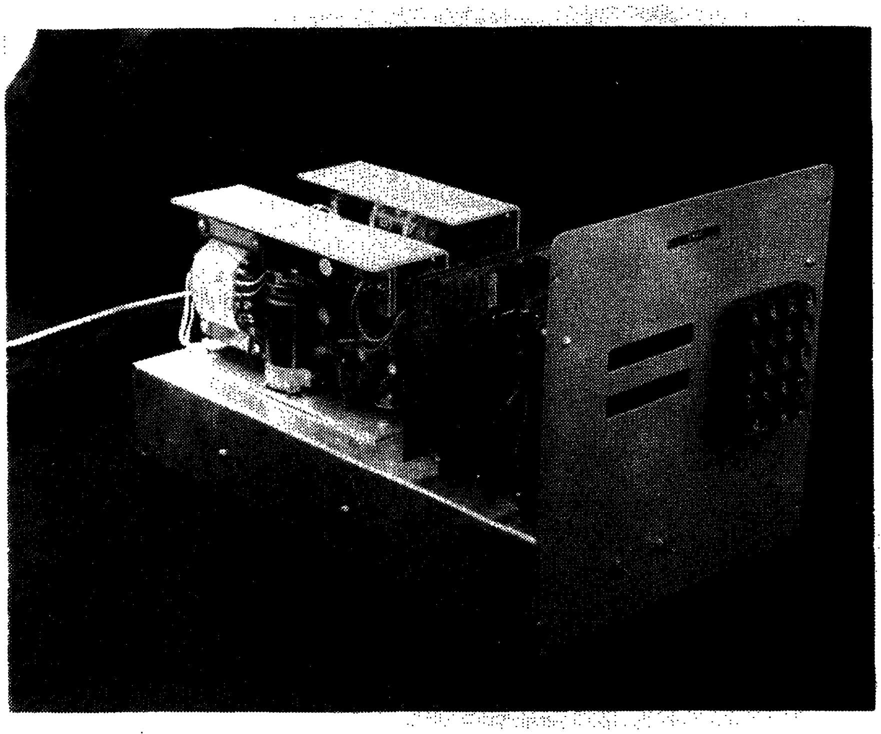

Figure 3.2

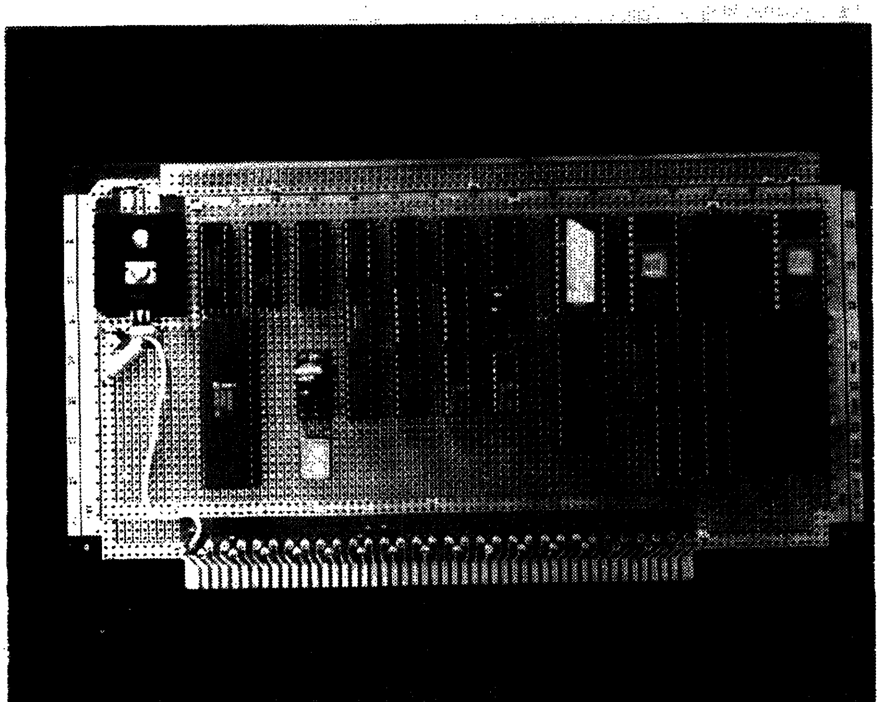

Figure 3.3

frequency measurement, plus a process level measurement. Internal logic then implements the FAPER control law.

The FAPER built for this project uses a general purpose single chip computer (INTEL 8748), with instructions programmed into an internal read-only-memory. Process setpoints are established by thumbwheel switches on the front panel. The process level is accepted as a voltage level, and digitized into a form useable by the computer using an analog-to-digital converter. The FAPER gives a single command output for "on" or "off."

A block diagram of the FAPER is shown in Figure 3.4, and a picture of the completed device is shown in Figures 3.5 and 3.6.

6.4 STATUS

At this time, the ERAC and FAPER described above have been constructed. At the time of the conference the software (the instructions residing in memory) for each device was being de-bugged, a time requirement well understood by participants fimiliar with development of microprocessors.

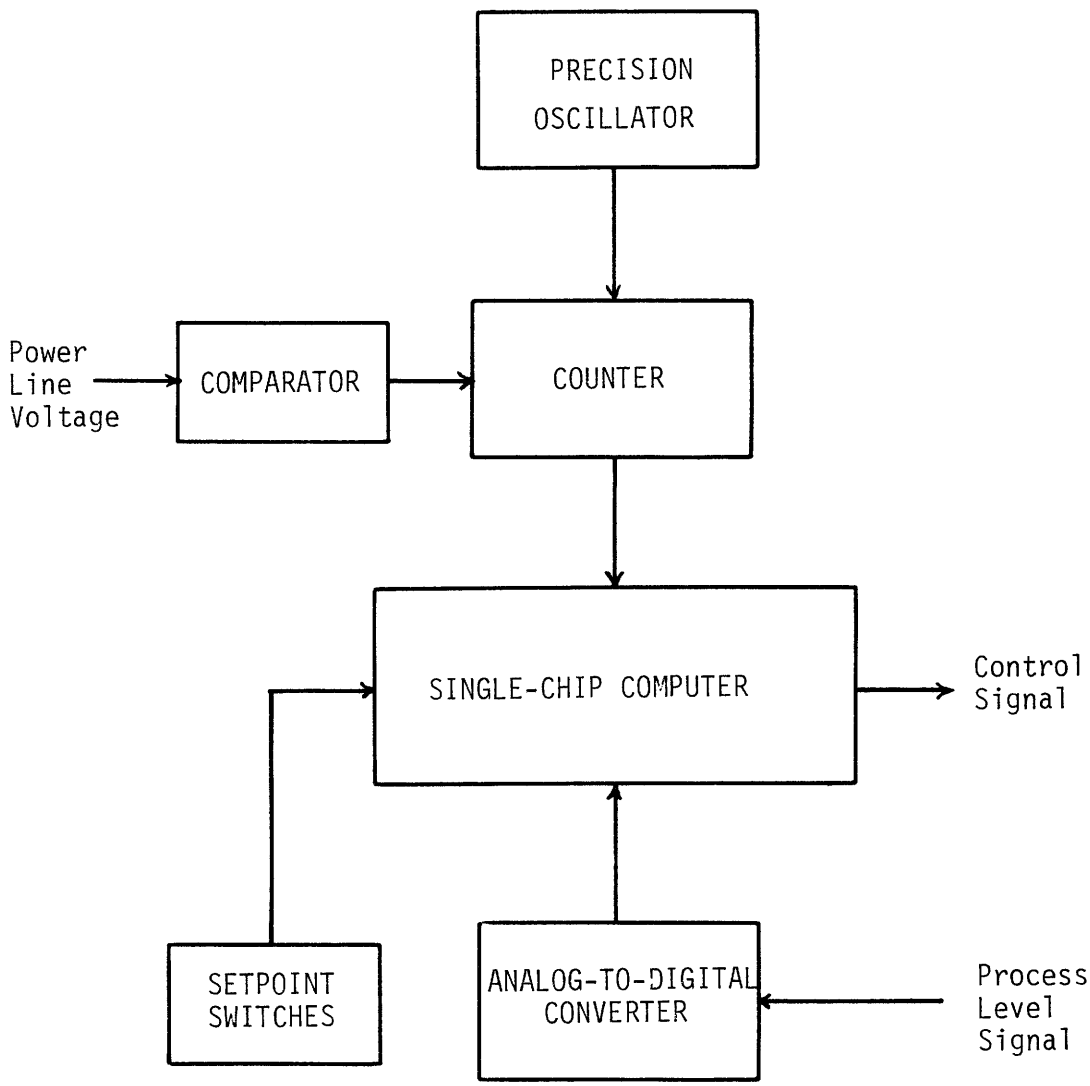

Figure 3.4: FAPER

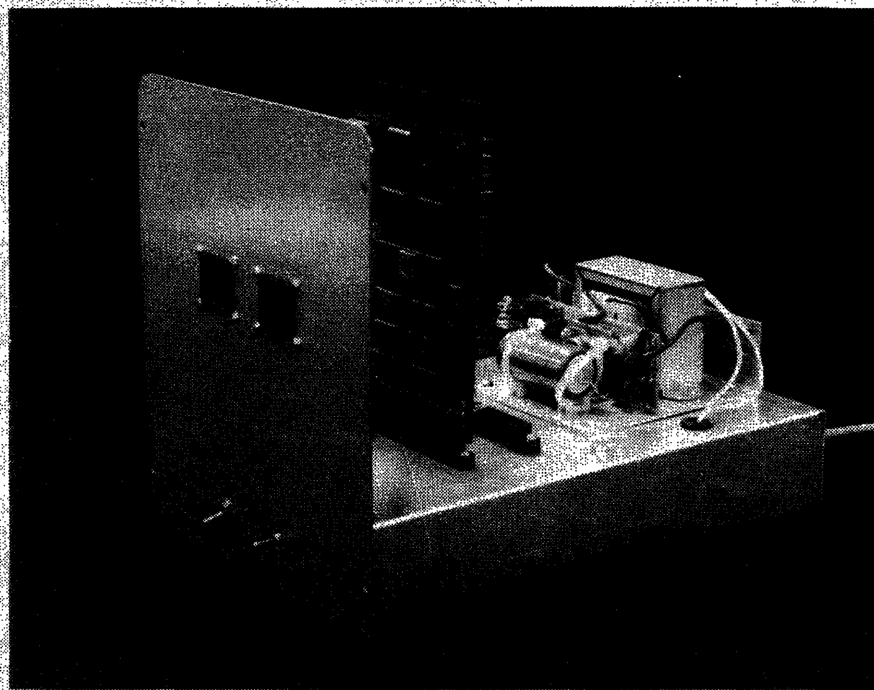

Figure 3.5

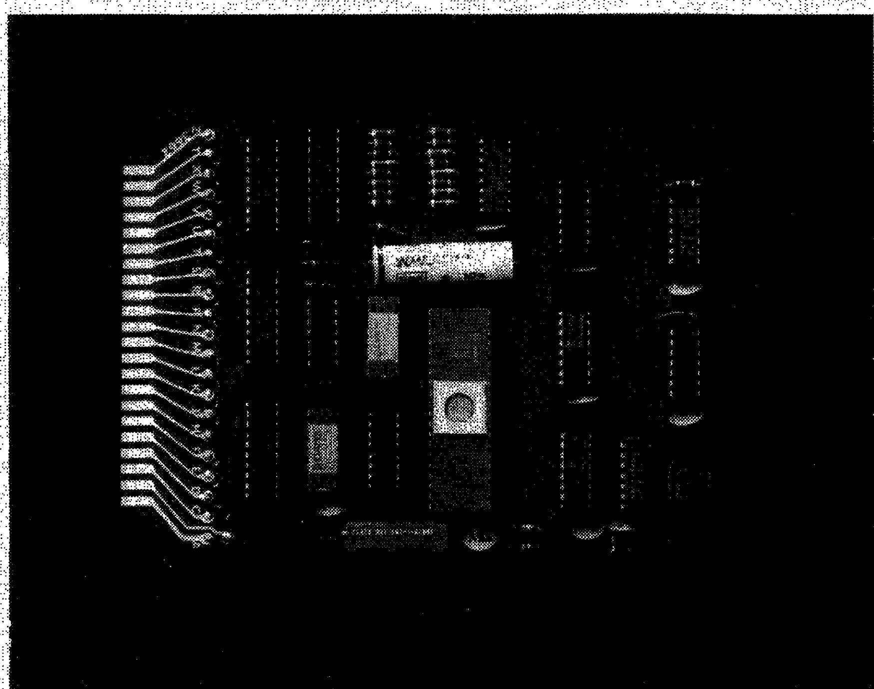

Figure 3.6

3.6 DISCUSSION

3.6.1 Introduction

In the discussion which followed the presentation on Customer Response Systems and consumer response to the Homeostatic Control concept, three major issues were addressed:

- o At what audience (consumer class) is the Homeostatic Control concept being aimed?
- o What kind of response can you expect from the consumer utilizing a Homeostatic Control system?
- o What will convince the consumer (public) of the value of the Homeostatic Control concept?

3.6.2 The Audience

The consumer class generally first expected to implement the Homeostatic Control concept is the industrial sector and some large commercial customers. This group is presently the only major sector conserving energy in the energy economy. The question asked was how can one expect industrial customers to increase their conservation costs by implementing the Homeostatic Control system when they are already conserving the greatest amount of energy? It is anticipated that the information gained from the usage of MIC[1] and similar interfaces will justify the costs incurred by the industry. Indeed, the information on variable rates sent to the industry will generate the required energy cost as their demand increases when the price is low and decreases when the price is high.

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[1]The Marketing Interface to Customer (MIC) is the communications link which transfers information between the utility and the customer.

A concern brought up was that Homeostatic Control might be perceived as an "engineer's toy." Indeed, it was pointed out it was an "economist toy" if anything and represented only a small change in the behavior patterns currently being shown by industry, the major change/advantage being that the industry and the utility were working toward the same objective. While the industrial and large commercial users are anticipated to be the first to implement this system, in the future smaller commercial and residential customers could implement the Homeostatic Control concept were it to be cost effective.

Since the industrial and large commercial sectors are the most likely first adopters of Homeostatic Control systems, the discussion centered around the issues and constraints relevant to their needs. Participants agreed that specific industries would be willing to reschedule processes, and reschedule people, in response to the spot rates. To respond would require that the given industry be able to gain (that it be cost effective). Other industries, especially those with lower energy to labor and/or capital ratios might not find the concept economically attractive and therefore might not adopt. Additional experiments and analyses are required to define the break points for individual industries.

Constraints that an industry need take into consideration are:

- o Since energy costs may only be in the range of 4-6% of the total costs born by an industry, what is the industry's incentive to use a system that would reduce energy consumption thereby reducing energy costs when they are such a small part of the overall cost structure?
- o Production rescheduling would be difficult given that (1) schedules are prepared in advance, (2) schedules may be set at

a central corporate location, not at the plant site, (3) certain processes cannot be economically rescheduled, and (4) to reschedule people who may not be willing to work other than those hours already scheduled.

Such a calculation was done for the New England Electric System (NEES) wherein customer response to pricing dislocations were tabulated. The following takes one through the calculation and typical response of the customer who was a small industry in the western part of the State of Massachusetts.

3.6.3 Customer Response: Industrial

- Consider j^{th}; process of an Industrial Customer

  x_j: average power of process j (KW)

  N_j: number of operators needed for process j

  $R(t)$: operator salary at time t ($/person hour)

- Define

  $p(t)$: spot price buy at time t ($/KWH)

- Assume j^{th} process can be rescheduled from t_1 to t_2

- Benefit Cost Ratio = $\dfrac{\text{Savings from Rescheduling (\$/hour)}}{\text{Cost of Rescheduling (\$/hour)}}$

$$= \frac{x_j[P(t_1) - P(t_2)]}{N_j[R(t_2) - R(t_1)]}$$

Assuming

$$P(t_1) > P(t_2)$$
$$R(t_1) < R(t_2)$$

. Define

$$A_j = \frac{x_j}{N_j} \qquad (\text{KW/person})$$

$$\frac{P_o}{R_o} = \frac{\text{nominal price}}{\text{nominal salary}} \qquad (\text{person/KW})$$

$$\delta = \left(\frac{R_o}{P_o}\right) \frac{\rho(t_1 - \ (t_2)}{R(t_2) - R(t_1)} \qquad \left(\frac{\%\ \text{price change}}{\%\ \text{salary change}}\right)$$

Then

. Benefit Cost Ratio $= A_j \left(\frac{P_o}{R_o}\right) \delta$

$$\delta = \frac{\%\ \text{price change}}{\%\ \text{salary change}}$$

. Assume

$$P_o = .05\ (\$/\text{KWH})$$

$$R_o = 5\ (\$/\text{person hour})$$

$$\frac{P_o}{R_o} = 10^{-2} \quad (\text{person/KW})$$

Then some representive values are:

	Benefit Cost Ratio
Electric Furnace	17δ
Soap Tower	2δ
Plastic Extraction Molding	$.1\delta$ to 1.5δ
Machine Shop	$.02\delta$ to $.2\delta$
Secretary	$.002\delta$

In summary, it was felt that the economic incentive for the utilities and some large commercial and industrial customers is likely already here. On the other hand, there needs to be more analysis and economic incentives for the small commercial and residential customer to incorporate Homeostatic Control into its energy supply/demand network. The question remains, however, as to the measurement of the benefits and costs associated with the rescheduling implied in the spot pricing scheme. While no specific calculations were possible in the preparatory work for the conference, the structure for the analysis and a set of generalized numbers were presented in the foregoing figures. It would be especially important to overcome the obstacle of mechanical errors emanating from the automatic devices provided on each customer's site. Such errors could ultimately doom the Homeostatic Control concept much the same as the problematic solar heating and hot water systems demonstrations did for the solar industry. The values are derived from earlier work in the northeast by Schweppe and Manichaikul (ref) and are broadly indicative of both the style of analysis required and the order of magnitude results one could expect.

3.6.4 What Response Can Be Expected From the Customer?

The customer's response is expected to be based on the individual firm's (individual's) economic interest and the magnitude of that interest. As was discussed at the end of the last section this economic interest will vary with energy usage, with energy intensity and with energy price. The discussion divide responses into those that could be expected from an industrial customer from the residential. Siting evidence from the San Diego Gas & Electric work with time variable rates for large industrial customers, it appeared that there was considerable ability on the part of specific consumers to alter their load and to reschedule given the appropriate signals from the utility. Discussion concerning smaller and residential consumers was less enthusiastic concerning their ability or desire to respond to such signals. An example given for residential water consumption had shown that at most four or five specific values for water could be used before the customer would be faced with information over load. A second point brought out in the residential discussion was the apparent value of repetition or habit in the response to specific rate structures, thereby arguing in favor of some type of regular time of day rates--the example given that of the telephone company.

Four specific steps were suggested for analyzing the potential response on the part of large consumers:

1) In depth research on customer processes and potential response areas.
2) Experimentation to determine the likely impact of these rates.
3) Development of support of regulatory community.
4) Educational programs for a broad range of consumers.

The final point from the discussion was one of caution concerning the reduction in cost associated with the control devices themselves. While it was agreed that the price of chips was likely to continue to fall, in all likelihood the chip will account for only a small portion of the overall cost of the control device.

3.6.5 SUMMARY

The aforementioned issues support the hypothesis that industrial and large commercial users will be the most likely first adopters of the Homeostatic Control system. As the system is more widely used, some residential customers are likely to install the system, but not to the same proportions as the industrial and commercial community.

CHAPTER 4: HOMEOSTATIC CONTROL AND UTILITY REGULATION

4.1 Introduction

The principal issues associated with the acceptance or implementation of Homeostatic Control by Public Utility regulatory bodies may be addressed in the following two areas.

Issues associated with the concept of spot pricing. Is spot pricing a concept that can be adapted into the legal requirements of public regulation?

- Given the state and Federal regulatory environment, can/will it adapt to a formula-based regulatory environment as opposed to a schedule system for utility rates?
- Given the Federal role in utility regulation and in particular PURPA, will Homeostatic Control systems add to the complexity or simplify the regulatory system?

Issues associated with the methods by which spot prices will be determined. Will spot prices utilize current embedded/average costing methodologies or will marginal costing be adopted by individual Public Utility Commissions?

- Marginal costing implies the existence of excess profits for the utilities. In what manner will such profits be redistributed to consumers?
- What impact will congenerators and small generators have upon both the price of electric power to other customers and what will be the price for electric power either brought by the congenerator or small generator or bought back from the congenerator and small generator by the utility?

The sections which follow will discuss Regulatory Practices and Homeostatic Control in section 4.2; Meeting Utility Revenue Requirements in section 4.3 and a discussion of Homeostatic Control and the Public Utilities Regulatory Policies Act in section 4.4.

Homeostatic Control, like any other innovative utility pricing or control system, presents regulatory agencies with a number of issues to resolve. Some of these issues are conceptual; e.g., Is the concept of spot pricing in accordance with the legal requirements of public regulation? Others are logistical; e.g., By what method are spot prices to be determined? The situation is complicated somewhat by the recent passage of the Public Utility Regulatory Policies Act of 1978 (PURPA), which in itself is creating ripples throughout the country because of the uncertainty surrounding the interpretation of a number of its key provisions.

This paper will investigate a number, but by no means all, of the ramifications of Homeostatic Control on the regulatory agencies and the effect of the regulatory environment on its implementation. Topics to be covered include a discussion of Homeostatic Control and traditional regulatory practice, looking at both conceptual and logistical issues; a more in-depth look at the problem of meeting utility revenue requirements under Homeostatic Control; and the relationship of PURPA and Homeostatic Control.

4.2 Regulatory Practice and Homeostatic Control

From the regulator's point of view, there are a number of unique features of Homeostatic Control that need to be examined to determine if they are in consonance with traditional regulatory practice and law. A few possible problem areas are discussed below as examples to be considered.

4.2.1 Spot Pricing

Perhaps the major innovation of Homeostatic Control is spot pricing, the determination of rates at the time of purchase, rather than the use of a prespecified, scheduled rate structure. Although there have been some experiments with this concept (e.g., San Diego), the closest most states have come to it is the monthly or quarterly fluctuation of the fuel adjustment charge in response to changing fuel prices, generation mix, and customer consumption. The concept of dynamic rates, therefore, first must be reconciled with the legal requirement of most states to have approved tariffs on file with the regulatory agencies. Traditionally, tariffs have included prespecified rate schedules as well as terms and conditions of service; however, unless a state's law requires prespecified schedules, the method of determining and applying rates can also constitute a tariff. For example, many states use electricity or gas adjustment clause tariffs that specify the method of calculating a variable adjustment charge. Conditions, such as upper limits of such charges, can also be included in the published tariffs to provide an automatic control against excessive rates in any given time period. Such tariffs, it seems, could also be used to implement spot pricing unless, as mentioned, statutory language requires a stricter definition.

The other innovative feature of spot pricing, besides its dynamism, is its two-way nature. That is, spot prices are determined both for customer purchases of electricity and for utility buy back of electricity. State regulatory agencies may or may not have jurisdiction over the buy back rates paid, for example, to cogenerators selling electricity to utilities. (See further discussion below in the section on PURPA.) If there is state jurisdiction these buy back rates might be subject to the usual tariff requirements or they might be covered by regulated contracts between the utility and the congenerator. Whichever method is used, the parties will have to be able to specify the methodology used in calculating the rate in order to receive approval from the regulatory agency. As above, unless there is a strict statutory requirement for prespecified rates, this should pose no undue conceptual problem to the regulatory agency. (As an example, many regulatory agencies currently approve contracts for interruptible purchases of natural gas, where the price varies according to the current market price of fuel oil.)

Spot pricing may, however, pose a logistical problem. Rates or charges based on a methodology require periodic regulatory review of the calculations made using that methodology. The reviews will have to be done in a timely fashion in order to be meaningful, and this will require a more or less continuous staff commitment. Regulatory agencies may be reluctant, because of budget constraints or other factors, to allocate staff and other resources to these periodic reviews. Unless the agency is willing to make this commitment, this logistical problem becomes a conceptual one as well; for the regulatory agency will almost certainly eschew a dynamic rate system over which it is unable to exercise its statutory obligation of review for fairness, accuracy, etc.

Another logistical problem with spot pricing is the format of the electric bills. It will be necessary to design a bill format that clearly presents consumption and price information for the entire billing period. Not only is this a legal requirement in most jurisdictions, but it is also a useful tool for customers who may be considering load management or energy conservation investments. If spot prices vary every five minutes, as is now envisioned, a graphical display of consumption and price might be a possible format. Whatever method is used, it will have to be easy to read so that, as mentioned below, the customer has an opportunity to fully understand and, if necessary, dispute the bill.

Another logistical concern is the need for an education program for those customer classes that will be affected by Homeostatic Control. Programs similar to those being offered by many utilities to explain time-of-use rates will be required. Customer understanding is clearly necessary if Homeostatic Control is to work and if it is not to receive immediate adverse reactions from the utility's customers.

In summary, a regulatory agency, in reviewing the concept of spot pricing, will probably find that such a concept can be legal and proper. However, unless the agency is willing and able to monitor and calculation and collection of revenues under spot pricing, to ensure a clearly understandable bill format, and to require a customer education program, it may not adopt the concept. Further development of Homeostatic Control, therefore, should include mechanisms for reducing the time and effort required of regulatory agencies in monitoring the application of spot pricing, in designing appropriate bill formats, and in designing customer education programs.

4.2.2 Marketing Interface to Customer

Another feature of Homeostatic Control, the market interface to customer (MIC) raises other issues of concepts and logistics. One of the uses of MIC can be automatic meter reading. Some jurisdiction may require on-site meter reading by utility personnel. If this is a statutory requirement, legislation would be required if the MIC were to be used for this purpose. If this is a regulatory requirement, new rules or regulations would have to be promulgated.

It is almost a certainty that the use of the MIC for automatic meter reading will raise the issue of invasion of privacy. With the MIC, the utility can monitor energy use by a customer on a more or less continuous basis. The seriousness of this as a privacy issue remains to be seen. The telephone company, for example, already exercises a similar capability, and the issue is usually not raised with that utility. However, since this will be a new application, the subject is likely to arise in any legislative debate or regulatory hearing on the subject.

If automatic meter reading as a concept is approved, at least one logistical problem remains. Even assuming the accurate reading of meters, there will be a need for a complaint mechanism so that customers can question meter readings that are perceived as incorrect. Most regulatory agencies currently have methods of resolving billing disputes, but these may have to be adapted to the particular characteristics of the Homeostatic Control system. As mentioned above, the bill format is an important part of this process. However, another minimum requirement will almost certainly be an on-site display of consumption that the customer can read to monitor his own electricity use and thereby compare his expectations with the bill received from the utility. Further development of the MIC should therefore include a device for on-site display or storage of electricity use.

4.3 Meeting Utility Revenue Requirements Under Homeostatic Utility Control

Summary

This section discusses some implications of Homeostatic Control on the electric utility rate-setting process. In particular, it focuses on the affect of Homeostatic Control on the ability of a utility to earn its allowed level of revenues and compares this situation with that resulting from the application of traditional time-of-use pricing. Mechanisms for insuring the comparability of allowed and achieved revenues are discussed. Special attention is paid the problems of the interplay of marginal cost pricing and Homeostatic Ceontrol as this affects utility revenues.

4.3.1 Allowed Revenues

An electric utility is permitted by a regulatory agency to collect revenues that allow the company to recover its costs and earn a reasonable return on investment. Revenues are generally set according to the following formula: $R = O.E. + V \times r$ where,

R = annual allowed revenues

O.E. = annual operating expenses for a test year

V = rate base (i.e., net plant in service) in a test year

r = allowed rate of return

Regulatory agencies vary in their definition of test year for rate-setting purposes. In establishing test year operating expenses, some agencies use a historic test year (e.g., the most recent 12-month period); some use a projected, or future, test year; and others use a combination (e.g., 6-months historic and 6-months future). Similarly, in establishing the test year rate base, some agencies use a year-end figure, and some use an average of the beginning and end of the test year.

The important feature of all methods, though, is that allowed revenues are based on a *pro forma* expectation of the utility company's costs. The rates that are devised to acquire the allowed revenues are similarly based on a *pro forma* expectation of consumption by customer class and within customer class.

4.3.2 Achieved Revenues

It can be seen from the above that, even without time-of-use rates, spot-pricing, or other innovative pricing schemes, the utility's ability to earn exactly its allowed revenues in a given year is unlikely. Achieved revenues in the years following a rate case can exceed the allowed revenues (if sales are higher and/or operating expenses are higher than expected). Thus, it is very unusual for a utility's achieved revenues to equal it's *pro forma* allowed revenues.

Given this uncertainty in normal circumstances, any rate system that is instituted because of its expected ability to influence price-sensitive demand lends additional uncertainty to the picture. Time-of-use rates, for example, are designed to reduce consumption during peak periods and redistribute that consumption to off-peak periods. To the extent that rates are properly designed and if all on-peak energy use is turned into off-peak energy use, achieved revenues need not vary from allowed revenues. However, if the reductions in peak energy usage are not transformed in corresponding increases in off-peak usage, revenue losses will occur. Similarly, if high on-peak rates are mistakenly assigned to inelastic demand, and on-peak consumption therefore, does not fall, excess revenues will be collected.

Thus, we find a generic problem with time-of-usage sensitive rates. If elasticities of demand are incorrectly calculated and incorporated into the rate structure at the time the rate structure is designed, the utility's achieved revenues will vary from its allowed revenues. As mentioned, this variation can either be positive or negative. Therefore, periodic adjustments in rate schedules, especially during transitional periods of rate innovation, will be necessary to insure that achieved revenues more closely approximate allowed revenues. As data on elasticity are gathered for the various customer classes, the process will evolve, and it can be expected that an equilibrium will be approached.

Spot-pricing under Homeostatic Control will, like traditional time-of-use pricing, face this problem. If the spot prices are set with no regard to likely demand elasticities, revenue overages or shortfalls will result. The situation is complicated somewhat in that spot-prices, especially during the transitional phases of its implementation, will be likely to change, not only in magnitude, but in pattern. These changes will make it difficult to predict elasticities and incorporate them into the spot prices.

Looking at it another way, one can envision three phases in the implementation of any time-of-use pricing, but especially in the implementation of spot-pricing and the rest of Homeostatic Control:

Phase I - Customers react to spot-pricing by changing energy consumption habits and their use of their existing stock of capital items (e.g., appliances and machinery). ("Instantaneous and Short-Term Elasticities")

Phase II - Customers react to spot-pricing by making changes in their capital stocks (e.g., more efficient appliances, load-controllable machinery). ("Long-Term Elasticity")

Phase III - Customers make minor changes in consumption patterns depending on period to period changes in spot prices. ("Long-Term Equilibrium")

The length of these phases cannot be known with certainty. Neither can the magnitude of the relative changes in consumption of each phases be predicted in advance.

Thus, utilities and regulatory bodies will be facing three dynamic and interrelated processes:

(1) Operating expenses and rate base will be changing over the years;

(2) The magnitude and pattern of spot prices will be changing over the years; and

(3) Customers' consumption habits and their elasticities of demand will be changing over the years.

Item #1 occurs now, even without time-of-use pricing or spot-pricing, and it is taken into account with the filing of new rate requests by the utility. In the 1950's, rate decreases were awarded as costs fell and consumption per customer increased. In the 1970's, rate increases are awarded in the face of rising costs and decreased or increased customer usage. A key feature of this process, however, has been the relative stability of rate levels and rate structures.

Time-of-use pricing and spot-pricing would still allow periodic rate cases to adjust company expenses and revenue requirements. However, one might be concerned about the inter-rate case period in which, because of the dynamics of pricing and consumption, achieved revenues might vary substantially one way or the other from allowed revenues. Mechanisms that can address this problem on a more or less continuous basis might be required and could be designed.

For example, a running balance of overages or underages could be maintained and applied as a periodic credit or debit to the current rate structure. Thus, if a utility's revenues for the month of April were much lower than projected, May's prices would be adjusted upwards to make up the difference. A degree of tolerance could be built into the system by, for example, having six-month rather than a one-month running balance. In addition, the threshhold level that would detemine what constituted an overage or underage could be set to avoid large fluctuations from month to month. This kind of process is common to the fuel adjustment clauses used throughout the country. In a number of states, fuel costs are estimated in advance and the fuel adjustment per kilowatt-hour is set in advance. Adjustments to the next month's or quarter's fuel adjustment are then made depending on the actual fuel used and its cost and the energy consumed by customers in the estimated period.

Objections to this running balance method might be expected, depending on its design. For example, regulatory agencies probably would not want the rate structure to track costs so closely that the company achieved revenues that guaranteed it a certain return.[1] (The fuel adjustment clause if often designed to guarantee a one-for-one pass-through of fuel costs.) If the whole rate structure were to guarantee this same one-for-one return, there would be no incentive for cost-control by the utility. (Indeed, this has been a complaint of the fuel adjustment mechanism.) This concern may be alleviated by setting a fairly high threshhold level of revenue underage because the running balance was to be applied to rates, and then the balance was to be applied to rates, and then the balance might not be applied in full. In contrast, a fairly low threshhold level of revenue overage probably would be set to ensure that the utility's earner return was not excessive. This method would require more bookkeeping and auditing than is currently done in most jurisdictions, but it appears to be a workable alternative.

Other schemes could be designed. For example, an escrow account could be established that would be applied every six months or year in the form of a rebate or surcharge on each customer's bill. This scheme has the obvious public relations advantages if there is a rebate and the obvious disadvantages if there is a surcharge. It also does not address the problem of a severe cash flow problem for a utility in the period between surcharges.

In summary, the type of scheme developed, and its sensitivity, could be adapted to the magnitude of the revenue problem. Alternatively, no new mechanism could be instituted, leaving the regulatory agency and the

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[1] Revenues are set to allow the utility an opportunity to cover expenses and earn a reasonable return. They are not meant to guarantee the company that return. The analogy is often given of a fishing license which, while allowing you to catch up to the maximum number of fish day, does not guarantee that you will do so.

utility to adjust allowed revenues in the current fashion, a rate case every few years. This latter course might be quite adequate if time-of-use rates or spot-pricing were instituted gradually, so that the revenue effect in any one year would be minimal.

4.3.3. Marginal Cost Pricing

The above discussion is complicated further if rates are set on a marginal cost basis rather than on an embedded cost basis. The "excess revenue" problem relating to marginal cost pricing has been discussed many times in the literature. Simply put, a problem arises if customers are charged the marginal price of generating capacity when the utility is only entitled to receive the embedded cost of capacity in its revenues. Recall that the rate-setting formula, above, allows a return on new plant in service. Thus, unless a regulatory agency allows construction work in progress in the rate base, the company is not permitted to earn a return on future plant. If rates are based on marginal (i.e., future) costs of capacity, and if new capacity is more expensive than existing capacity, achieved revenues will exceed allowed revenues (unless demand is so price elastic that consumption drops enough to compensate for the higher rates per kilowatt-hour.)

This excess revenue problem is usually handled by a method known as the "inverse elasticity method". If, under the traditional time-of-use rate scheme, expected revenues will always exceed allowed revenues because of increasing marginal costs, the inelastic blocks of consumption (usually, the initial blocks) are discounted, providing the utility with less revenue than otherwise. The rationale for this scheme is that, by discounting these early inelastic consumption blocks, no increase in consumption will occur because of the discount. (If the discounts were applied to elastic blocks, increased consumption in these blocks would result and would defeat the purpose of the marginal cost pricing.) While this method has been debated pro and con, it does offer a possibility of matching allowed and achieved revenues under tradition marginal-cost based time-of-use rates.

However, if spot-pricing is implemented with marginal cost pricing, the inverse elasticity method cannot be used to solve the excess revenue problem, at least not in the same way. The basis of spot-pricing is to let the customer respond to the spot price in his or her own way. One cannot say that the first unit of consumption occuring at, say, 5:00 PM, is inelastic, for it might be occuring at that time because the user is sensitive to price at that time. In short, there is no way to determine a priori which uses of electricity are least elastic for a given customer. In theory, one could say that the first few kilowatt-hours of all those purchases at 5:00 PM might be inelastic and therefore should be discounted; but this would have to be done at every other 5-minute interval of the Homeostatic Control day as well.

Of course, approximations could be made. If it were determined that, on average, demand in late evenings was inelastic, all spot-prices from, say 10:00 PM to midnight might be discounted. Some, especially price sensitive customers, could garner an extra benefit from this added discount, but consumption for all customers might not change appreciably. The danger of this technique with spot pricing would occur if a miscalculation of the inelastic demand period were made, and a large shift of consumption occurred to the discounted time period. This could actually result in a revenue shortfall as opposed to the revenue overage, in effect "over-solving" the excess revenue problem. (Similar problems exist with traditional time-of-use pricing. If the elastic, rather than inelastic blocks, are mistakenly discounted, it will stimulate an inappropriate shift in consumption.)

In summary, the use of marginal cost pricing in setting spot prices, if these costs exceed test year embedded costs and unless consumption were drastically reduced as a result, could result in excess revenues to the utility, unless a mechanism similar to the inverse elasticity method is applied.

4.4 Homeostatic Utility Control and the Public Utility Regulatory Policies Act of 1978

A review of the provisions of the Public Utility Regulatory Policies Act of 1978 (PURPA) and the characteristics of Homeostatic Control indicate that the two are compatible. The tests that are to be applied by state regulatory agencies as part of their consideration of the ratemaking standards set forth in PURPA generally are applicable to Homeostatic Control and should present no fundamental difficulties for those agencies. The exception may concern interruptible rates, which are envisioned by PURPA and may or may not be a part of Homeostatic Control and quality of service pricing, which is a new concept not envisioned by PURPA. The problems that will be encountered by the regulatory agencies in evaluating Homeostatic Control for purposes of PURPA are equivalent to the problems they will face in evaluating traditional time of use pricing. The data collection requirements of PURPA may assist in implementing Homeostatic Control, and Homeostatic Control, in turn, may assist utilities in meeting these data collection requirements. Finally, PURPA's ratemaking requirements on cogenerators and small power producers can be easily incorporated into Homeostatic Control.

4.4.1 PURPA Sectins 113 and 115

Congress, in passing PURPA, found that there was a need for a program "providing for increased conservation of electric energy, increased efficiency in the use of facilities and resources by electric utilities, and equitable retail rates for electric customers." The program established in the Act requires that the state regulatory agencies with jurisdiction over electric utilities formally consider a number of ratemaking standards and make a determination as to whether their adoption of those standards would further the purposes of the Act. Six ratemaking standards are set forth in the Act:

(A) Cost of service. Rates charged by a utility shall be designed, to the maximum extent practicable, to reflect the costs of providing electric service to each class of customers. The cost of service shall be determined by methods that permit identification of differences in cost incurrence: (a) for each class of customers, attributable to daily and seasonal time of use of service; and (b) attributable to differences in customer, demand, and energy components of cost. In prescribing such methods, the agency shall take into account the extent to which total costs to an electric utility are likely to change if additional capacity is added to meet peak demand relative to base demand and if additional kilowatt-hours of electrical energy are delivered to customers.

(B) Declining block rates. The energy component of a rate shall not be sold according to a declining block rate structure unless that structure is cost-justified.

(c) Time-of-day rates. The rates charged to each class of customers shall be on a time-of-day basis, reflecting the costs of providing service to that class at different times of day, unless such rates are not cost-effective. Cost-effective rates are defined as rates whose long-run benefits to the utility and the customers in the class concerned are likely to exceed metering and other costs.

(D) Seasonal rates. The rates charged to each class of customers shall be on a seasonal basis, reflecting the cost of providing service to that class in different seasons of the year. No cost-effectiveness criteria is required for these rates.

(E) Interruptible rates. Each utility shall offer industrial and commercial customers interruptible rates wich reflect the cost of providing interruptible service to that class of customer.

(F) Load management techniques. Each utility shall offer to its customers such load management techniques as the regulatory agency has determined will be practicable, cost-effective, reliable, and provide useful energy or capacity management advantages to the utility. Cost-effective techniques are those that are likely to reduce maximum kilowatt demand on the utility where the long-run cost-savings to the utility of such reduction are likely to exceed the long-run costs to the utility associated with the implementation of those techniques.

The conference report accompanying PURPA expands on a number of these standards and gives more indication of the intent of Congress in enacting the Act. Perhaps the most significant statement in the conference report is one that asserts that the conferences:

> Do not intend that time-of-day or seasonal variation in rates exactly reflect the time-of-day or seasonal variation in costs of providing service. A less than proportional increase in rates at

> the peak may be appropriate to send the signal to the consumer to reduce elastic demand for peak energy without causing unnecessarily high rates which have no effect on inelastic demand at the peak.

This statement appears to be a retreat from the pure cost-of-service based pricing set forth in the Act. It apparently stems from a concern about inelastic household or other users facing high rates on peak. This presents a bit of a dilemna to regulatory agencies because it introduces equity concerns into a process otherwise directed towards economic efficiency.

The Conference Report also asserts that the requirement that rates "take into account" differences in customer, energy, and demand charges does not imply a specific methodology for determining cost of service. Congress was reluctant to legislate the use of embedded, short-run marginal, or long-run marginal costing methodologies, and thus this decision is left up to the regulatory agencies.

Two of the components of Homeostatic Control, spot pricing and the FAPER, bear on the provisions of Sections 113 and 115 of PURPA. (The MIC, while involved, is essentially a communications tool, and need only be considered in terms of its cost and its effect on the cost-effectiveness of the Homeostatic Control system. As we shall see below, the MIC can have a role to play in meeting other PURPA provisions.)

The first, concept of spot pricing is in consonance with the purposes of these sections of PURPA in that spot prices charged by a utility can meet the cost of service standard, the time-of-day standard, and the seasonal rate standard of the Act. In fact, one can reasonably assert that spot pricing exceeds the expectations of Congress in its desire to have rates vary with time-of-use. It is to be noted, too, that Congress did not require that rates be set in the traditional (i.e., prespecified, scheduled) manner. There is no hint of a prohibition of dynamic, constantly adjusting charges.

However, as explained in another paper of the Conference, it may be necessary to modify the strictly cost-based spot prices to include a "quality of supply" component. In short, it might be necessary to ensure system stability by sending higher-than-cost prices to customers before capacity limits are reached. In theory, maintaining the quality of supply could be considered a cost of service, but it is not a cost in the traditional use of the term. In fact, if quality of service pricing is used, it actually represents a short-term price adjustment used to avoid either (a) short-term costs of system instability or (b) long-term costs of new capacity. The level of quality of service prices would be based on the desired customer response, not on a physical cost of providing service. (The upper limit of such prices might be the cost of additional generating capacity, since this would be the long-term solution to the anticipated peak load; but even higher prices could be charged if there were a policy decision to avoid building new capacity.)

Quality of supply pricing was not envisioned by the authors of PURPA, and so its compatibility with the purposes of the law is debatable. Taking a broad view of the law and its desire to make efficient use of existing generating facilities, quality of service pricing presents no problem. Taking another view of the law, and especially the Conference Committe's concern about high on-peak rates, quality of supply pricing might face problems. More investigation of this topic is necessary, particularly the extent to which quality of supply pricing will actually be needed, and if needed, the magnitude and duration of the prices charged.

Second, spot pricing bears little relation to declining block rates. In theory, the two could exist simultaneously, although this appears unlikely. While spot pricing presumes no particular rate structure, it would seem that declining block rates are incompatible with a pricing scheme that has constantly varying rates according to demand on the utility system. (One would have to imagine, for example, a declining block rate that falls with each additional use of energy that occurs between 5:00 and 5:05 PM, while another declining block rate would exist for energy use between 5:05 and 5:10 PM, and so on.) It thus seems that the two concepts are inconsistent in practice.

Third, Homeostatic Control may or may not include interruptible rates. Under spot pricing, a customer would set his or her own threshhold for load shedding, and this threshhold would be based on the spot price reaching a certain level. The customer's "reward" for interrupting his load would be the avoidance of high electricity costs. The utility's reward would be a reduction in load during peak periods, although as noted below, the exact amount of the reduction would not be known with certainty until it actually happened. Other customers would benefit, too, in that their spot-buy-price for electricity would drop (or rise more slowly) due to the withdrawal of the interruptible customer.

It could thus be argued that the existence of spot-pricing makes it difficult to calculate a special "cost of providing interruptible service" to a given customer class, for the cost of providing interruptible service under this scheme would be the same as the cost of providing firm service. The capacity and energy cost savings traditionally gained through the use of interruptible price rates would, it could be argued, no longer have meaning under Homeostatic Control.

The use of spot-pricing will allow these cost savings to be recovered by all customers, whether or not they fall into the traditional interruptible categories. A convincing argument could thus be made by a regulatory agency that interruptible rates are inappropriate under spot-pricing, or that they are equivalent to the same prices faced by all customers. It is uncertain whether this line of reasoning would satisfy the purposes of PURPA.

On the other hand, it can also be argued that there is a place for interruptible rates, even given the existence of spot-pricing. The advantage of interruptible rates to utility companies is the knowledge that a definite amount of load can be disconnected in a time of a capacity shortfall. Spot-pricing does not carry with it the same degree of certainty about customer responsiveness. (For example, this may be true particularly during periods of extended hot, humid weather, during which time demand on peak becomes less and less price elastic.) Thus, it may be appropriate, especially during the transition period in which spot-pricing is being introduced and in which its effectiveness in reducing peak demand has not been measured, to continue the use of interruptible rates to help insure system stability. Thus, special interruptible rates might still be offered in recognition of those customers' contribution to the quality of service being rendered by the utility to its entire service area. As mentioned in other papers of this Conference, interruptible rates could be designed in such a way as to offer industrial and commercial customers the option of being interruptible customers in some time periods but not in others. In summary, if one adopts this general point of view, the use of interruptible rates is consistent with the concept of Homeostatic Control and should present no problem with regard to satisfy the purposes of PURPA.

Finally, the innovative load management technique envisioned in Homeostatic Control is the use of the FAPER. (Other load management techniques would certainly be appropriate under Homeostatic Control and, in fact might be stimulated by spot-pricing.) As presently conceived, the FAPER would be owned by the electricity customer and adapted to his or her own power and energy requirements. However, there is nothing inherent in the concept of the FAPER that would prohibit its being provided by a utility company if the regulatory agency found it to be "practible, cost-effective, etc."

In summary, the components and characteristics of Homeostatic Control appear to be in consonance with the purposes and ratemaking standards of PURPA, with the possible exception of the interruptible rate concept included in PURPA, and the quality of supply pricing, which will possibly be part of Homeostatic Control.

The other problems to be faced by regulators and utilities with regard to these sections of PURPA under Homeostatic Control are not unique to the Homeostatic Control system of electricity pricing and management. The debates over marginal and embedding costing methodologies will apply to both Homeostatic Control and traditional pricing systems. The legal and other procedural requirements of PURPA similarly are not affected by the method of utility pricing ultimately arrived at. The question of the appropriate pricing of electricity on peak - whether to allow the full cost of service to be included in peak period charges or whethr to reduce peak rates in anticipation of some inelastic demand -- similarly must be faced under both Homeostatic Control and traditional time-of-use pricing methods.

4.4.2. PURPA Section 133

Section 133 of PURPA directs the Federal Energy Regulatory Commission to periodically collect cost of service data from the country's utilities and provides that these data must be separated, to the maximum extent practicable, in customer, energy, and demand cost components. Among the data to be collected are the following:

(1) The cost of serving each customer class, including the costs of serving different consumption patterns with each class, based on voltage level, time-of-use, and other appropriate factors; and

(2) Daily load curves for all customer classes, combined and for each class for which there is a separate rate, representative of daily and seasonal differences in demand.

It appears that these data requirements may be of assistance to regulators and utilities trying to institute Homeostatic Control because they will provide base line information, as well as periodic updates, on costs of service and load patterns. The data can thus be helpful in initiating Homeostatic Control by assisting in determining the potential cost-effectiveness of the system before it is fully implemented. The data will also provide information helpful in monitoring the on-going effectiveness of the Homeostatic Control system and in making adjustments during transitional phases.

It also appears that utilities faced with these data requirements may reap an additional advantage from Homeostatic Control and, in particular, the MIC. The MIC offers the potential for simplified data gathering by the utility, providing a flexibility in sample selection, data collection time periods, and actual processing of data that could be of great benefit in recording accurate samples of consumption of different customer classes at a lower cost than is now possible.

4.4.3. PURPA Section 210

Section 210 of PURPA concerns cogeneration and small power production and directs the Federal Energy Regulatory Commission to prescribe rules to encourage cogeneration and small power production and to require purchases and sales of electricity between such sources and the electric utilities. The rules must insure that the rates for electricity purchases by the utility from the cogenerator (buy-back rates) shall be just and reasonable to the customers of the electric utility and in the public interest and not discriminatory against the cogenerator. An upper limit is placed on these rates, equal to the cost of electric energy to the utility which the utility would othrwise pay for its own generation or purchase from another source. This "incremental cost" of electricity can be defined as either instantaneous-incremental cost or as a longer-term cost of electricity. The law also provided that sales by the utility to the cogenerator shall be priced in such a way as to be just and reasonable and in the public interest and not discriminatory against the cogenerator.

This section of PURPA is also in consonance with the features and principles of Homeostatic Control. Spot-pricing offers the opportunity for both purchase rates and buy-back rates to be applied, however, these are defined by the appropriate regulatory authority. (There is still a debate as to who will be the "appropriate regulatory authority", for the question of state vs. Federal jurisdiction over the actual rates charged remains to be resolved.) Homeostatic Control offers a flexibility in the setting of purchase and buy-back rates that may not have been envisioned by Congress (i.e., dynamic rates depending on the utility's incremental cost of energy), but there appears to be no prohibition against the kind of system envisioned under Homeostatic Control.

4.5 Discussion

4.5.1. Introduction

To what extent will the regulatory environment permit Homeostatic Control to be developed and implemented? How does the Homeostatic Control concept relate to the current and future regulatory process? How will the logistics of the two operate? These questions posed at the outset of this session were addressed during the ensuing discussions concerning the current regulatory system, pricing systems within the regulatory framework, regulatory practices and processes, and proposed implementation procedures of Homeostatic Control. The following provides a summary of the comments and discussion that followed the regulatory presentation.

4.5.2. Current Regulatory System

One participant commented that the stated functions of today's regulatory system are to protect the consumer, protect the utility (by allowing a fair rate of return), and by setting rates. In other words, the focus of today's regulatory environment involves a set of overlapping objectives. These include:

- o maximizing the welfare of the people, reflecting as much as possible market mechanisms in the process,
- o providing "just and reasonable" rates to utility customers and co- and small generators, and
- o providing an economic/financial and regulatory framework within which the utility can operate.

Recently passed Federal legislation, PURPA (P.L. 95 - 617), incorporates the aforementioned while giving more guidance to state utility regulators than before.

Another commentator compared today's regulated utility system to that of the railroad business wherein:

- o the cost of doing business is reflected only accidently in rates charged to customers,
- o resistance to change is a way of life, and
- o the burden of proof in a regulatory proceeding remains with the company, not with the regulatory commission.

He then suggested that while regulatory commissions should be educated to get beyond the "nothing should ever be done for the first time" philosophy, researchers should refrain from studying a technology to death. In so doing, some of the pitfalls that the railroads have faced may be circumvented by the utility industry.

4.5.3. Issues Concerning Homeostatic Control and Its Interaction with the Regulatory Environment

Certain aspects of the interaction of Homeostatic Control and the regulatory environment should be studied in greater detail. The discussion identified some of these issues:

- Tracking costs utilizing the Homeostatic Control concept (i.e., accounting for the costs incurred during a small time period such as five minutes may represent a concept highly similar to a cost of service tariff. This is not totally in accord with present regulatory practice. There is some concern that rate cases could become a way of life as companies will continually be expected to prove costs before a rate change is allowed to occur. Presently, for example, New Mexico is having trouble implementing a cost of service tariff, thus raising questions about the practicality of the Homeostatic Control concept. With cost of service tariffs, such as fuel adjustment charges, there is no real incentive to economize since all costs are simply passed through to the customer. Another point raised was that under cost of service concepts the utility doing the poorest job (e.g., in failing to supply the most economical power) would automatically be able to charge the highest rates. Would this not occur under the Homeostatic Control concept as well? A counter agrument was raised to indicate that such situations occur with the fuel adjustment clause and in New York at least specific in efficient expenditures for fuel have been disallowed. Finally, the cost of service concept may redistribute the risk of doing business (reference the Alaskan Pipeline case) to ratepayers and away from the utility's stockholders.
- Utility incentive(s) - Presently, regulatory lag provides incentive to the utility to maintain efficient operations between rate cases. However, with a spot pricing mechanism,

much of this incentive is eliminated since changes in rates would occur on a continuous basis.

- Cost-Benefit - Questions benefit of Homeostatic Control in utility planning operations. Cannot time-of-day rates do what Homeostatic Control is supposed to do? How will Homeostatic Control impact upon utility operations and planning?
- How does one plan to implement the pricing scheme proposed under the Homeostatic Control concept at the State and Local level? Some could not see from the discussion how Homeostatic Control could accomodate the large array of formulae and rules presently enforced by the state and local government regulatory agencies. It was stated that Homeostatic Control could accommodate the different formulae and approaches by each state because of its flexibility.
- How quickly will costs underlying the formulae be updated? Every new transmission line? If not, how are these changes reflected in the price to the consumer? j Do you gain any more by going to a short term pricing basis over prespecified time-of-day? Some agreed that the multiple rate levels were not as complex concept as was first hinted. For example, one could use just four rates, changing twelve times a day. (Discussion referred to a study on water rates that found that any more than four or five rates confused the residential consumer.) It was then pointed out that Homeostatic Control was likely most immediately applicable to industrial and commercial customers where multiple rates are currently a way of life.

- How will quality of service component of spot pricing be accepted by regulatory agencies? On the whole, saw no problems unless its complexity baffles the legislators. (Also see Quality of Supply Pricing discussion which follows.)
- Hostility of regulatory bodies to change may be alleviated with the accrual of better data and information that has been required by PURPA.
- What are regulators going to do with the Homeostatic Control concept when the concept cannot definitively predict revenue requirements? Through gradual implementation, thus more understanding, this question and others like it would be answered. In addition given current regulatory structures revenue requirements are met only on average.
- What is the objective function of Homeostatic Control? Who should respond and what are the responses supposed to be? What exactly do you want the pricing mechanism to do? (See Thursday/or Friday morning discussion.)
- What specific problem will the close interaction of the utility and the customer help to solve? Homeostatic is not an overnight phenomenon - not meant to be an immediate answer to all problems. Its goal is to solve technical, not regulatory issues over the longer term. For instance, quality of service and reliability could be improved through customer participation in contrast to today's operational environment.

4.5.4. Definitively Positive Aspects of the Interaction

Two areas were identified that would be positively affected by the introduction of Homeostatic Control within the present utility environment. First, spot pricing will provide an impetus for the deregulation of power production. This was considered to be a healthy sign. Secondly, the Homeostatic Control concept through its pricing mechanism is capable of basing its prices on natural cycles (minutes, days, etc.) rather than accounting constructs (years and months). This is expected to be a constructive change from the present pricing system.

4.5.5. Summary and Conclusions

In summary, there appears no serious conceptual problem to the implementation of Homeostatic Control given our present and/or evolving regulatory system. The above questions are not considered to be intractable. (Most agreed that FERC should provide more leadership in regulatory innovation/streamlining.)

However, it was pointed out that through the gradual implementation of Homeostatic Control, the knowledge gained will mitigate uncertainties concerning the system. Indeed, it was suggested at several points in the discussion that the best way to identify the costs and benefits of Homeostatic Control is to get a utility and an industry together and approach their public utility commission with a proposal to implement Homeostatic Control on an experimental basis. In so doing, a learning situation is set up in which these parties would benefit while guaranteeing no net cost to the remainder of the utility's customers.

Chapter 5: POWER SYSTEM OPERATION

5.1 Introduction

The key issues to be discussed at the conference in the area of power system operation are:

- o Is there a need for a quality of supply component of spot price?
- o Is there a need for the customer to participate in frequency and voltage control?
- o What are the present trends and future issues in power system operation?

Some of the important factors related to these questions are:

- o How does Homeostatic Control address these?
- o What are the trade-offs between alternative approaches to power system operation?
- o What interactions are there between the proposed control schemes?
- o Will Homeostatic Control provide stable operation?

Material included is as follows:

5.2. Power System Dynamics and Homeostatic Control

5.3. Quality-of-Supply Component of Spot Price.

5.4. Generation Frequency Control

5.5. FAPER Operation

5.6. IEEE Spectrum Paper: Power Systems 2000

5.7. Discussion

"Power System Dynamics..." (5.2) provides a general overall view of system dynamics with emphasis on how homeostatic concepts interact with them. "Quality-of-Supply Spot Price" (5.3) discusses how system operational needs lead to a spot price which contains a "noneconomic" component. "Generation Frequency Control" (5.4) is a tutorial writeup on power system frequency-power dynamics and control that is provided for conference attendees without extensive power system backgrounds. "FAPER Operation" (5.5) uses the background of (5.4) to discuss the "Frequency-Adaptive Power-Energy Rescheduler" (FAPER). A copy of an IEEE Spectrum paper (July 1978), "Power Systems 2000", is included in (5.6). It provides an even more general background on the possible future of power system control and operation.

5.2 Power System Dynamics and Homeostatic Control

Homeostatic control consists of the mutually beneficial interaction of many semi-autonomous subsystems comprising utility generation, transmission network, distribution network, and customers. All customers would have the right to buy (consume) or sell (generate) electricity, and the responsibility to contribute to the stable and orderly operation of the overall system. Homeostatic Control introduces new modes of dynamic behavior because it emphasizes customer responsiveness to changing supply conditions. This is potentially as important to the short time scale of power system dynamics as it is to the longer time scale of changing economic factors such as cost of generation.

This document reviews the important modes of power system dynamic behavior and the time scales in which they occur. The major control mechanisms introduced by Homeostatic Control are summarized, and their effects are discussed in a general way.

5.2.1 Time scales for power system dynamics

Power system dynamic behavior is conventionally divided into a number of time scales. These divisions could still be applied under Homeostatic Control.

Protection Time Scale (less than 200 msec)

Rapid switching is needed following equipment failure, lightning strikes, etc., to preserve system integrity and to prevent equipment damage. No new procedures have been postulated under Homeostatic Control, but all private generation would have to provide suitable disconnection facilities. The overall problem of distribution system protection is clearly made more complex by the presence of even small amounts of distributed generation, but not Homeostatic Control per se.

Fast Dynamics (less than 1 minute)

Most dynamic responses of turbine-generators occur in this time scale. Changes in demand can also take place, particularly at low levels of aggregation. Alternator field voltage and turbine governor control systems have an important effect, as do voltage control and automatic load shedding at load substations. Major disturbances and even system collapse can occur in this time interval due to loss of generation or of main transmission components. The likely future trend to increasing numbers of small, customer-owned generating plants may aggravate distribution system voltage control problems, and frequency control to a lesser extent.

Slow Dynamics (less than a half hour)

This is the realm of boiler response, automatic generation control, and economic load dispatch in conventional power system operation. The major decisions about generation scheduling and network configuration are made in this timescale.

Daily, Weekly, and Long-term Trends

There are cyclic variations in the electricity demand of most power systems with daily, weekly, and longer time-scales, due to life-style and weather-dependent factors. The changing costs of electricity production during these cycles are not adequately reflected in price in conventional power system operation.

5.2.2 Control mechanisms introduced by Homeostatic Control

Homeostatic Control emphasizes customer responsiveness to changing power system conditions, via both normally available information such as voltage and frequency, and the new concept of time-varying spot prices for customer consumption and generation. Three types of control schemes have been postulated so far:

a) Frequency-based schemes in which the natural frequency responsiveness of demand is enhanced. The FAPER has been designed to do this without deleterious effects to the customer. Similar concepts may be applicable to customer generation. The FAPER is discussed in detail in a separate report.

b) Voltage-based schemes which enhance load-voltage responsiveness. Voltage control at the distribution level may be aggravated by the introduction of customer generation. Customer devices to control voltage may have a beneficial effect on system operation. Controlled reactive power sources may be available from customer generation even when real power generation is not taking place.

c) Dynamic variation of spot price. The main justification for time-varying pricing is to reflect the changing expenditure costs of supply. However, time-varying price could also be used to notify the customer of changing operating conditions that affect the short-term viability of the power system and thus the quality of supply. This would introduce a powerful new control mechanism that could lead to more efficient (hence cheaper) power system operation, and also ensure the stability of the spot pricing mechanism itself. This concept is discussed in more detail in a separate report, and is referred to as a quality-of-supply component of spot price.

5.2.3 Time scales of operation for Homeostatic Control schemes

The frequency- and voltage-based control schemes can respond in principle as quickly as the information content of the respective signals will allow. The speed and accuracy of the measurement devices may often be a limiting factor. These controls would normally be effective throughout the fast dynamics and slow dynamics time scales defined earlier. Information transmitted via spot price can only be updated at the price notification rate, which may be too slow for the fast dynamics period. A concept of "spot price interruptible" has been introduced for this reason, in which a customer may choose at each price interval to place part of his load under utility switching control during the next price period (only for emergency use). This provides a flexible load interruption capability that can be used as an alternative to backup equipment capability.

5.3 Quality-of-Supply Component of Spot Price

Homeostatic Control introduces the concept of spot price to reflect the time-varying cost of delivering electric power to a customer. While normally dominated by expenditures associated with capital equipment, fuel and maintenance, the nature of electric power systems ensures that more emphasis must be placed on costs associated with maintaining the quality of the product than in most other industries. Customers already pay for the features deemed necessary by the electric utility in this regard, but the spot price concept would allow these issues to be handled in a more efficient manner and would permit the customer some say in selecting the supply quality he or she needs, and the opportunity to contribute to maintaining supply quality if so desired, in terms of his or her own cost-benefit analysis.

Supply quality issues arise from the desire to maintain high standards of supply voltage, frequency, and waveform purity at all customer terminals, except in very rare circumstances. Many conditions must be fulfilled to meet this criterion, but the major issues may be grouped as follows:

(i) the need to maintain voltage and frequency stable during normal operation, including the effects of interactions between the many control mechanisms present in a large power system.

(ii) The need to avoid noncontractual load shedding or system collapse in the event of unexpected disturbances or failure of any major item of equipment, or group of critical items.

(iii) The need to avoid system operating trajectories that may take the system or individual components outside the normal operating boundaries set by stability and overload criteria.

(iv) The need to maintain voltage waveform standards at the distribution level in the presence of switching transients, load-induced harmonics, normal load variation and in the future, variations in customer generation.

These conditions are met in normal power system planning by providing spare equipment capacity and installing control centers and control mechanisms to monitor and control utility operation. Customers remain essentially unaware of the importance of these features although they pay for them through their electricity bills. Escalating costs and environmental restrictions on system expansion are tending to increase both the cost and importance of these measures.

A component of spot price related to quality would tend to act in a feedback manner to improve the quality of supply. Examples related to the four previously mentioned groupings are as follows:

(Example i) Control mechanisms are present on many items of power system equipment to assist in maintaining supply standards. Equipment installed by customers (such as FAPER or voltage control) to achieve the same ends would be very beneficial to overall system operation, and could be rewarded by a component of spot price that increased as voltage or frequency fell. It should be possible to obtain the most economic trade-off between customer and utility equipment costs by correct adjustment of this price component.

(Example ii) Power utilities provide backup equipment to cover the unexpected loss of generation, transmission, or distribution components. An alternative in most cases would be to immediately disconnect an appropriate component of load downstream of the device in the rare case of actual device failure. Customers could be given the choice of allowing part or all of their load to be interrupted at will by the utility during the next pricing interval. In return they would get a price discount. For example, if operating policy dictated the need for extra spinning reserve in the next half hour, its cost could be computed, and a price component introduced, ranging from zero towards the equivalent cost level. Customers could pay the additional charge, disconnect their load, or convert all or part of their load to interruptible, for which they would not have to pay this particular price component. Reserve would thus be obtained in the cheapest possible manner and customers would have some say in the supply reliability they require, and the ability to adjust the amount of interruptible load at each price interval. The same principle could be followed at a more local level to provide backup for items of distribution equipment.

(Example iii) In the course of system operation it may become clear that the power system trajectory is heading towards an unstable state. For example, load may be increasing towards the limit of available generation. Rather than an almost inevitable system collapse or involuntary load shedding, a component of spot price could be introduced to notify customers of the impending problem and to discourage any further increase in load.

(Example iv) Voltage transients and harmonic distortion may cause harm to some customer equipment and are often produced by equipment installed by other customers. Spot pricing would allow for a charge to be levied depending on the particular usage pattern of a device and the extent of disturbance caused by it to other customers. A neighboring customer may install equipment which reduces the disturbance of the offending device to the system. In this situation charges paid by the offending customer to the utility could be partly reimbursed to the neighboring customer.

One further reason for a quality component of spot price is to ensure the stability of the spot price/demand/generation system itself. For example, if spot price starts to rise, customers may actually temporarily connect more load on the assumption that the price may rise even further in the future. A component of spot price may be needed to stabilize these dynamics, based on a predictive model of customer response to price change.

The effectiveness of quality of supply components of spot price will depend on the length of the pricing interval relative to the time scales of power system dynamics. Interruptible load, FAPERs and the like will be more important for a longer price interval than for a shorter one. The interruptible load component of price may not be needed at all if spot price could be varied instantaneously; however the importance of the other quality of supply components would not be affected.

The previous discussion has centered around the customer buying price and its influence on demand behavior, but the same principles apply to the buy-back price and customer generation. During emergency conditions when there is a local or system-wide shortage of generation, the value of customer generation will depend on the price users are prepared to pay, which may be higher than the economic expenditure cost. Here the quality of supply component could be used (as in example (iii)) in a feedback fashion to achieve a balance between supply and demand, affecting both buy and buy-back price. During normal operating conditions, frequency and voltage control, transients and harmonic distortion (examples (i) and (iv)) may be important for customer generation and may tend to reduce its desirability if there is an excess of generation. In this situation the quality of supply component may reduce both buy and buy-back prices until a satisfactory balance is achieved.

In all cases the quality of supply component of spot price would be used in a feedback mode to achieve a goal related to the overall viability of the electric power system. The amount of price variation will depend largely on customer ability and willingness to reschedule generation and load. In many cases the revenue obtained through this price term would be reimbursed to those customers contributing to supply quality (by customer generation, FAPERS, voltage control and the like). Overall, the quality of supply component of spot price is important to the philosophy of Homeostatic Control in that it permits the interaction between utility and customers to ensure the short-term viability of the power system (one day or less) that the standard economic indicators cannot provide.

The detailed structure of buy and buy-back prices and the dynamic interaction of utility and customer decisions are described in the appendix.

APPENDIX TO 5.3

1. Structure of spot price

a) Customer buying price (in principle this price could be different for every customer on the system).

Buying price for customer k, $r_{cb,k}(t) = r_{cb,k,ex}(t) + r_{cb,k,q}(t)$ where

$r_{cb,k,ex}(t)$ = expenditure price = component dependent on expenditures, determined by embedded costs, marginal costing, etc. as desired.

$r_{cb,k,q}(t)$ = quality-of-supply price = component dependent on quality-of-supply issues and used in a feedback mode to maintain system viablility.

Note that $r_{cb,k,q}(t)$ can be separated into a part that must be paid by all customers and a part that need only be paid for firm supply (i.e., non-interruptible) during the next price interval. Neither part has a clear economic basis although both may be related to future expenditures that may or may not occur. Many factors may be present in $r_{cb,k,q}(t)$ with their relative importance depending on the properties of the particular power system.

b) Customer buy-back price

This has the same structure as $r_{bb,k}(t)$ and should be constrained to be less than customer buy price.

$$r_{bb,k}(t) = r_{bb,k,ex}(t) + r_{bb,k,q}(t)$$

where

$r_{bb,k,ex}(t)$ = expenditure component based on the incremental cost at the point of supply (fuel, losses, maintenance)

$r_{bb,k,q}(t)$ = price component (positive or negative) reflecting the change in quality of supply caused by substitution of customer generation for utility generation.

2. Major decision processes associated with spot price in Homeostatic Control

The decisions are interacting as previously discussed, and as illustrated in Figure 5.1. The processes may be summarized as follows:

1. Each customer optimizes his demand and local generation trajectories given present price, past history and future predictions, as well as present and future needs. Minimizes [own cost, inconvenience] on an hourly to daily basis essentially without reference to other customers. Many decisions occur in parallel.
2. Utility optimizes utility generation trajectory and network configuration given customer demand/generation trajectories, weather, interruptible loads, FAPERs, etc. to minimize [cost of supply LOLP, etc.]. This occurs in normal power system operation.
3. HV network price trajectories are determined given all available information to minimize [error from specified profit, risk of system collapse and/or overload, instability in price/demand response and power system dynamics].

4. Distribution network prices are set given HV network prices, local losses and local operating conditions to minimize [local cost of supply, risk of overload or loss of supply, voltage error from nominal].

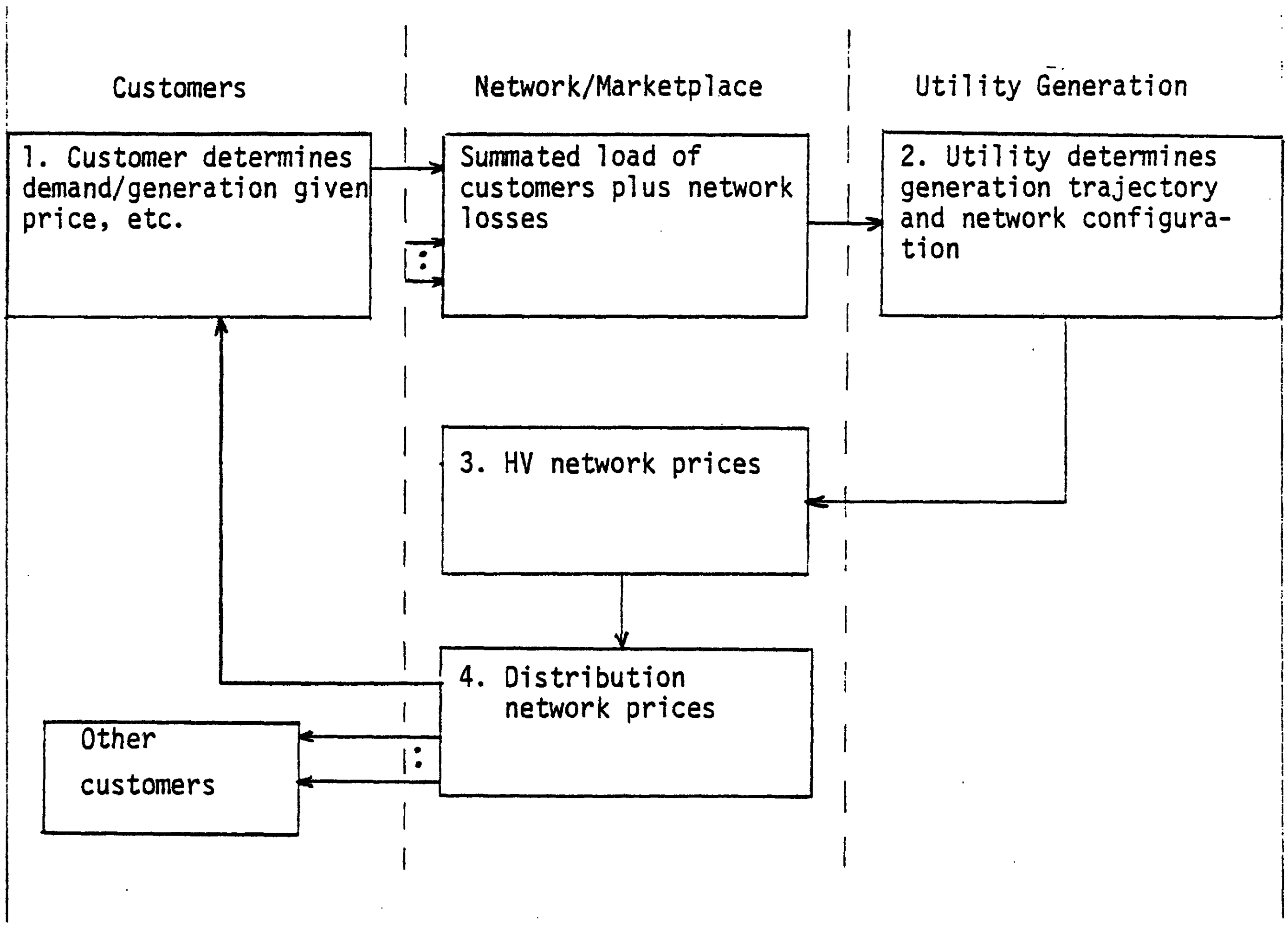

Figure 5.1 Major decision processes associated with spot price in Homeostatic Control

5.4 Generation Frequency Control

5.4.1 Introduction

Power system operation, at a macroscopic level, involves a complex energy balance between the non-electrical energy supplied by the primary sources--mechanical energy (from steam, water, wind, tides,...), solar energy, conceivably chemical energy, etc.--and the energy consumed in the system (predominantly as electrical energy supplied to loads, but also as energy losses associated with conversion, transmission, distribution, etc.).

As a first step towards understanding this energy balance, consider the situation where a single machine (turbine-generator) serves an isolated load. The situation is schematically represented in Fig. 5.2.

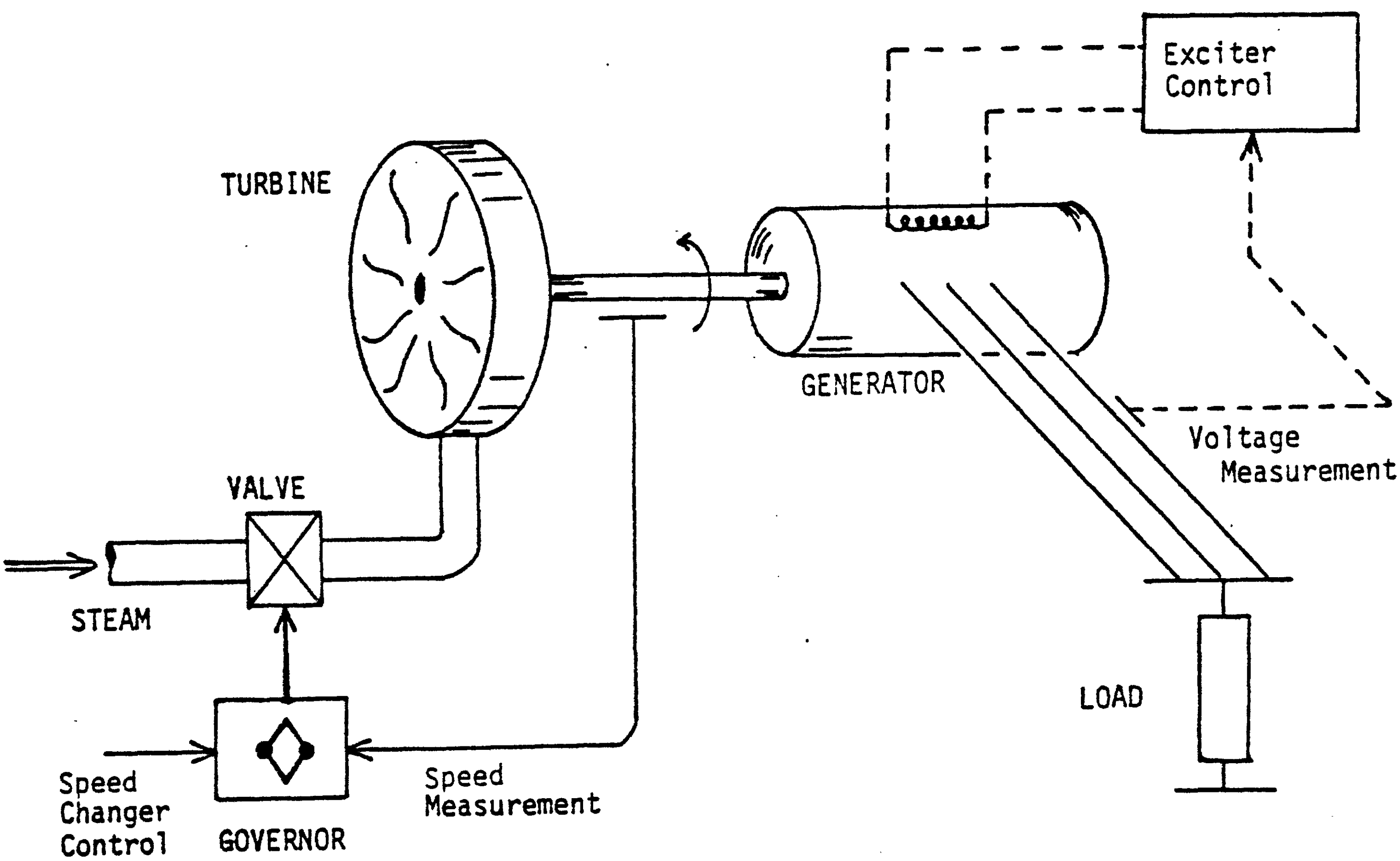

Figure 5.2 Basic single-machine power system

5.4.2 Single Machine Serving Isolated Load

In undisturbed or steady-state operation, a constant mechanical power is delivered to the turbine-generator combination. This power is converted by the generator into an equal amount of electric power that is supplied to the load. (For the purposes of this discussion, all losses are neglected.) The voltage waveform at the load terminals consists of a cyclic (sinusoidal) variation at a frequency that is directly determined by the speed of rotation of the generator. (The amplitude of this waveform is controlled by the exciter control loop shown in dotted lines in Fig. 5.2. The exciter control system is not considered further here, except to note that its function is to adjust the generator field current so as to maintain the amplitude of the cyclic voltage waveform.)

Consider now the effect of a disturbance to the above steady-state operation, specifically one caused by a sudden but sustained increase in load power. Since the mechanical power input to the system has not changed at this stage, the energy to supply the load comes from the kinetic energy of the turbine-generator shaft, and results in steady deceleration of the shaft. Correspondingly, the frequency of the load voltage waveform begins to steadily decrease. Two levels of control action now go into effect, one aimed at arresting the drop in frequency, and the other aimed at restoring the frequency to its original value.

The former action, that of arresting the fall in frequency, is the result of the "natural action" of the governor. The governor senses the drop in shaft speed and opens the steam valve to a position proportional to the fall in speed, thus steadily increasing the mechanical power input to the turbine-generator and steadily decreasing the rate at which the shaft speed falls. If no other control action were to take place, the end result would be that the frequency would level off at a value below the original level, and the new mechanical power input would equal the new electrical load power.

It is necessary, however, to do more than simply arrest the fall in frequency that follows a sudden load increase. In order that electric clocks, motors, etc., function properly, and, as importantly, because the generating plant is "tuned" to operate most efficiently at 60 Hz and may suffer damage (due to mechanical resonances in the turbine, etc.) at frequencies as little as 0.3 Hz away from 60 Hz, it is important to <u>restore</u> the frequency to its original value. This second level of control action is obtained by means of the governor <u>speed changer control</u> (shown in Fig. 5.2) in the following way.

The speed changer position is continuously adjusted, essentially independently of (but concurrent with) natural governor action, so as to open the steam valve (and hence increase the mechanical power input) at a <u>rate</u> proportional to the instantaneous frequency "deficit." Thus, while the natural governor action alone would only result in frequency levelling off at some reduced value, the effect of the speed changer control scheme above is to continually increase the mechanical power input to the shaft for as long as there is a frequency deficit, thus eventually restoring frequency to its original value. At this point, the new mechanical power input is equal to the new electrical load power (but this increased power input is now completely due to the altered speed changer position, since the frequency has returned to its original value and eliminated the contribution of the natural governor action). This control scheme is, for technical reasons, known as integral control, and constitutes the most basic form of automatic generation control (AGC).

The picture that has been developed so far of the system response to a sudden increase in load is summarized in Fig. 5.3 (with the numerical values being typical). The response to a decrease in load is identical, except for changes in the signs of perturbed quantities.

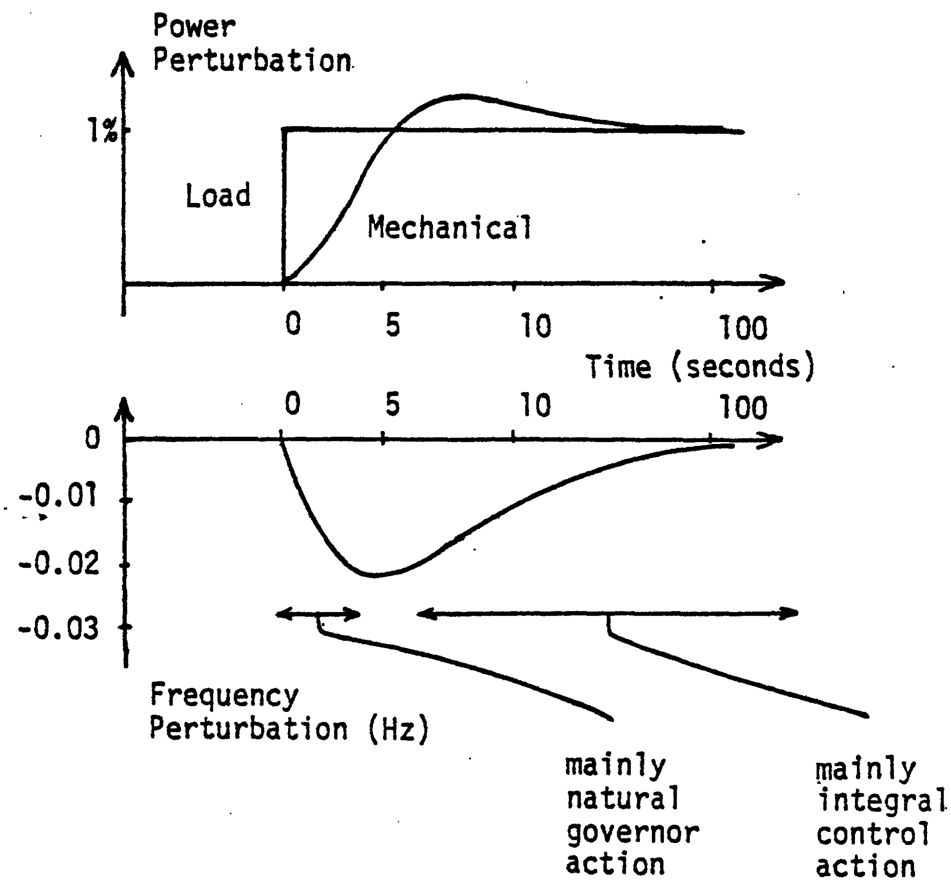

Figure 5.3 Power and frequency responses to step increase in load

A more careful analysis requires better modeling of governor action, of integral control implementations, of turbine-generator behavior, of the fact that load is somewhat dependent on frequency, etc. The simplified description is however sufficient to illustrate the general features that are to be expected. The main points to be noted in summary are the following:

-- load perturbations are instantaneously accommodated by corresponding perturbations of the kinetic energy of the turbine-generator shaft, with concomitant shaft acceleration and deceleration;
-- natural governor action on a short (0-5 seconds) timescale tends to limit frequency excursions from 60 Hz;
-- integral control via the governor speed changer acts on longer time scale (5-100 seconds) to restore frequency to 60 Hz.

[The above control scheme serves to restore frequency in the steady state to 60 Hz, and hence in the steady state one finds that electric clocks are once more running at the correct rate. However, the clock rate perturbations due to the <u>transient</u> frequency perturbations will have resulted in clocks exhibiting an error in the actual <u>time</u> they indicate. For example, if frequency fell to an average value of 59.99 Hz over a one-hour period before being restored to 60 Hz, clocks would slow down correspondingly, and be $.01/60 \times 3600 = 0.6$ seconds behind time at the end of the hour, though running at proper speed at the end of the hour. The way this is handled in practice is to set limits, say $\pm$ 3 seconds, on the allowable accumulated time error. When one of these limits is reached, the speed changer position is offset a certain amount in the appropriate direction so that <u>average</u> frequency is restored to zero, and the time error is concurrently brought to zero.]

The preceding analysis has dealt with the rather simple and practically unlikely case of a single machine serving an isolated load. In practice, a power system is immensely more complicated with several machines (of different types) serving load in one area, and separate areas connected via "tie lines" to form an interconected <u>power pool</u>. Each of these levels of aggregation is considered below.

5.4.3 Operation of a Multi-Machine Area

An <u>area</u> is roughly taken to mean a portion of the power system that has primary responsibility for meeting the demands of the loads within it. Typically, areas coincide with the domains of control of the separate power companies that comprise a power pool. The generators in an area act in unison, under centralized area control, to manage the variations of frequency with load. The basic principle here is the same as in the case of a single machine, except that the AGC signals to the individual speed changer controls are determined at the <u>area control center</u>, from observations of system frequency, and are then transmitted to the different machines as appropriate. (The natural governor action, on the other hand, takes place locally of course, since each machine is equipped with its own governor.) The above description is expanded in the following paragraph.

The major difference from operation of a single machine lies in the fact that it now becomes important to allocate the changes in steady-state generation (necessitated by changes in load) among the various generators in such a way as to "optimize" overall operation. Several factors enter this process. First of all, generating plants are not equally amenable to the variations in generation called for by AGC action. Typically, large fossil-fuel units and nuclear units are run at constant generation levels, while AGC action is mainly provided by small or medium size (under 600 MW) fossil units, by hydro units, and by combustion turbines. Furthermore, those units which do participate in the AGC scheme have different limitations on the range over which their generation may reasonably be varied, and on the rate at which this variation occurs. Other considerations that enter the optimization process are such things as the relative costs of fuels, pollution levels associated with different sorts of plants, the need for reserve generation (see below), etc. Based on such factors, the AGC signals to the individual speed changer controls are adjusted by the area control center in such a way as to appropriately allocate steady-state generation. The optimization aspects of AGC, as described above, overlap so-called economic dispatch issues.

Before moving on to consider the operation of interconnected power pools, some final remarks on area control will be made. Though the focus of the discussion has been on the control actions needed in an area to cope with load perturbations, it is common for major system disturbances to be caused by loss of generation (due to problems at the generating station itself or with transmission lines carrying generated power into the area). It is for this reason that generation areas are required to have various levels of reserve generation. These reserves are classified on the basis of their relative availability when called upon. "Spinning reserve" refers to the amount of generation that is "instantaneously" available (i.e. on a timescale of seconds to minutes) and consists of units that are fully operating but only partially loaded. Areas are typically required to maintain a spinning reserve that is comparable with the output of the most heavily loaded unit. Other reserves include hydro and combustion-turbine units, which can be brought up in minutes, "low bank" reserves comprising steam plants idling at pressure and heat levels below operational levels, and "cold reserves" that are operative but not in operation.

Another remark that needs to be made is that although the word "automatic" was used to describe the above generation control schemes, there is still a considerable amount of human monitoring, decision, control, and communication involved, especially under conditions of large and potentially traumatic changes in load or generation.

5.4.4 Operation of an Interconnected Power Pool

A power pool comprises many areas connected together via tie lines. Areas can now interchange power with neighboring ones to improve overall system behavior under both normal operation (short-term and long-term) and emergency operation. Control strategy, i.e., for pool operation, will not be considered in any detail here. It suffices to note that the main extension from area control concepts is that now each area control center uses observations of not only the local frequency perturbations but also of perturbations in its tie line flows, in order to determine the AGC signals to the speed changers of machines in the area. Thereby, in the hypothetical steady state, the frequency in each area is restored to 60 Hz and tie line power flows are back at prearranged values. (These prearranged or scheduled interchanges are designed to take advantage of differences between the daily, weekly, or annual energy usage patterns of the various areas, and reduce the ratio of peak to average generation for each area.) In practice, of course, persistent load or generation fluctuations give rise to continuous fluctuations in area frequencies and tie line interchanges.

The term 'local frequency' was used in the previous paragraph to draw attention to the fact that in any multi-machine system there is no unique global frequency: the frequency measured at one point will differ from that at another. This is mainly because the perturbations of system kinetic energy needed to accommodate load fluctuations involve dynamic swings of the different turbine-generator shafts, each with its own characteristics, and each affected in a different way by the distributed load fluctuations. It turns out that the frequency perturbations <u>within</u> an area occur essentially in unison, because of the close and multiple (i.e., 'strong') couplings between generating units in an area. For this reason, the description of area operation tacitly assumed a well-defined area frequency. However, distinct member areas of a pool that are only weakly coupled to each other can have noticeably different frequency perturbations.

5.4.5 Concluding Remarks

One class of system operations not yet mentioned is concerned with protective relaying and switching in a power system. They serve to avoid equipment damage and preserve system integrity. They occur automatically on a time scale of fractions of a second (say less than 200 milliseconds), and are occasioned by such events as line faults, lightning strokes, loss of field excitation in generators, etc.

There are, needless to say, countless other factors that have been ignored or glossed over in the above sketch. Power systems are perhaps the largest engineered systems known. They are, to a major extent, the result of "evolution by parts," so much so that very many interesting and important questions remain regarding how the parts affect the whole. This has been an attempt only to provide a simple account of the major factors and considerations entering the control of generation.

The Appendix that follows presents data taken from the literature to demonstrate the sorts of frequency fluctuations that follow from the preceding discussion, and as observed in actual and simulated power system operation.

APPENDIX TO 5.4

Dynamic Behavior of Power System Frequency

I. Normal Operation

The first figure, Fig. 5.4, illustrates the fact that system frequency is continually varying due to load and generation changes.

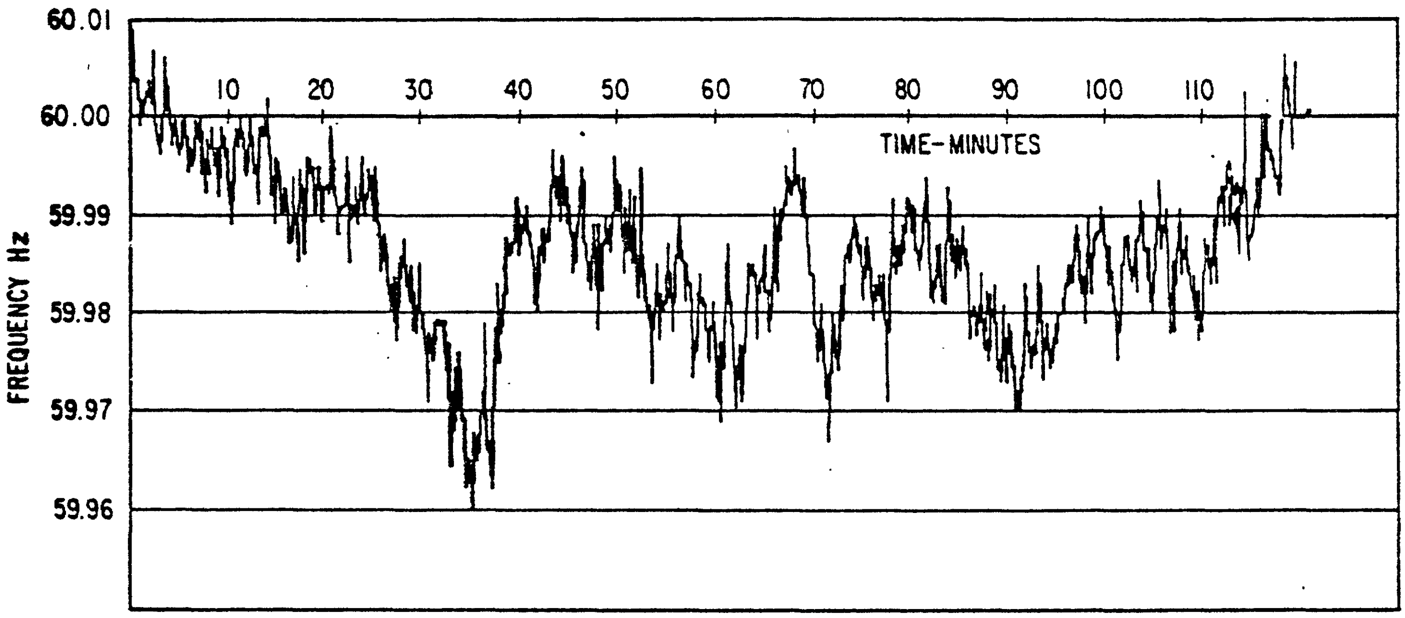

Figure 5.4 Trace of system frequency in U.S. Eastern Interconnection over a period of 2 hours. Trace is characterized by fairly rapid fluctuation of about .01 Hertz and larger excursions which last for several minutes or hours.

The following figure, Fig. 5.5, confirms that the extent of typical frequency fluctuations is of the order of 0.01 Hz (cf. also Fig. 5.3 of the text).

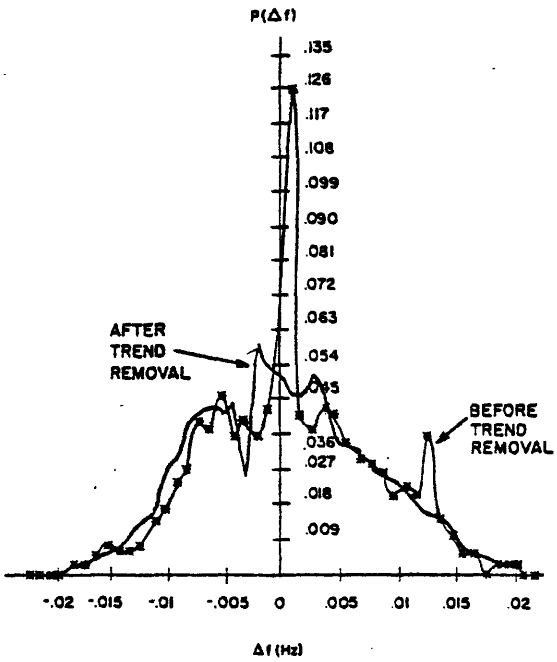

Figure 5.5 Probability density function of system frequency deviation for August 6, 1977 data. Sharp peak at 0.001 Hz is due to instrumentation defect. (* is before trend removal, and heavy line is after trend removal.)

It is also of interest to know the characteristic time scales on which the frequency fluctuations occur. In the discussion of single-machine dynamics (cf. Fig. 5.3) it was said these were on the order of 5-100 sec. This is in agreement with Figs. 5.6, 5.7 below, which show that most of the fluctuation lies in the 0.5-6 cycles/minute range.

Fig. 5.6

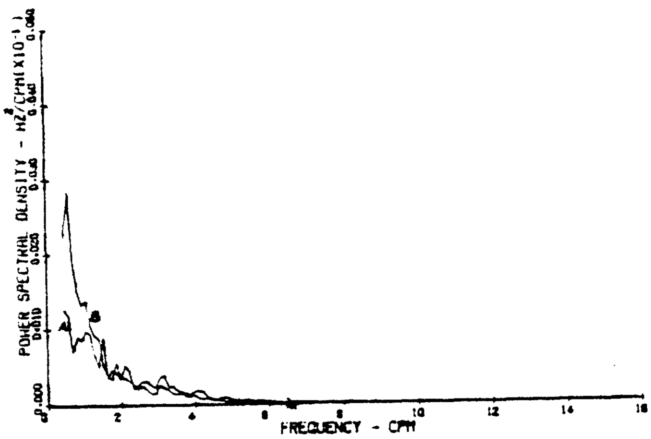

Fig. 5.7

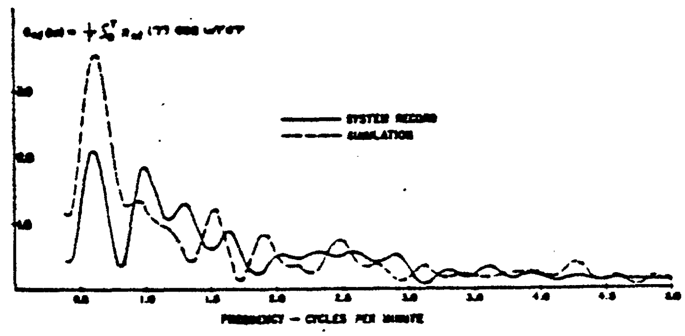

Figure 5.6 Power spectral density functions of system frequency deviations for heavy load data (Curve A) and for light load data (Curve B)

Figure 5.7 Relative power spectral density function of system frequency

The lower frequency spectra are associated with load changes and colored by AGC response while the higher frequency spectra are colored by governor response. The natural frequencies of the governor loops are in the 2-6 cycle per minute range.

Fig. 5.8 illustrates, by means of simulation results on a multimachine system, that the frequency perturbations at different points of a system are different. All the curves (except the dotted line) denote measurements of frequency deviation at different generator locations.

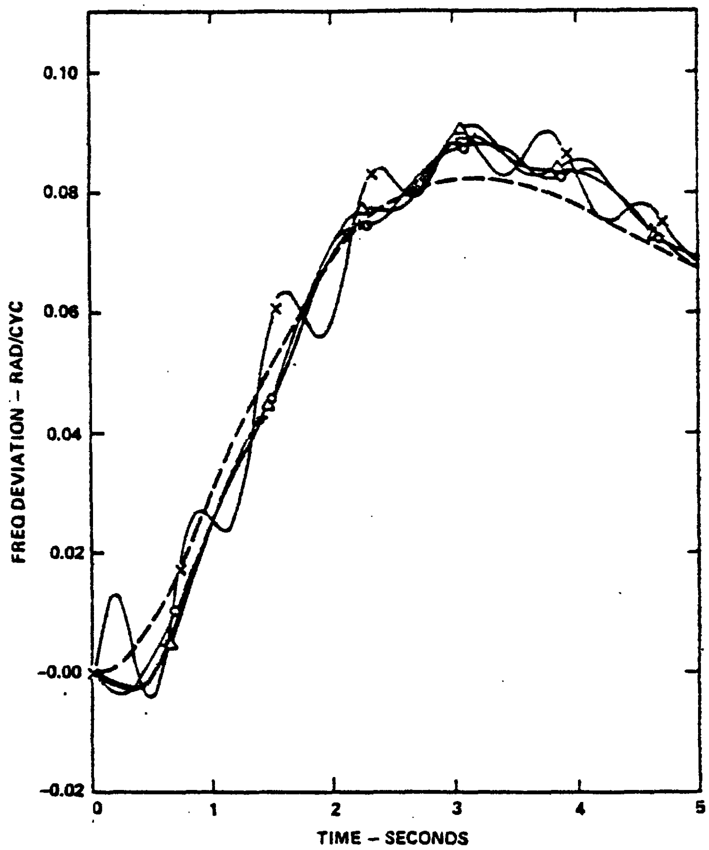

Figure 5.8 Frequency Deviation Comparison for different machines (simulation study)

II. Response to Large Disturbances

The following record, Fig. 5.9, presents an interesting picture of system frequency deviations after large disturbances. Two line faults, occurring 25 seconds apart, caused system frequency to drop all the way to 59.9 Hz. In Fig. 5.10 are shown the responses to this pair of faults of the two plants available for control at the time. It is evident that both pick up generation within 2-4 minutes. (The total generation power lost as a result of the faults was 620 MW, and it is seen that the two controlled plants together increase generation by essentially that amount.)

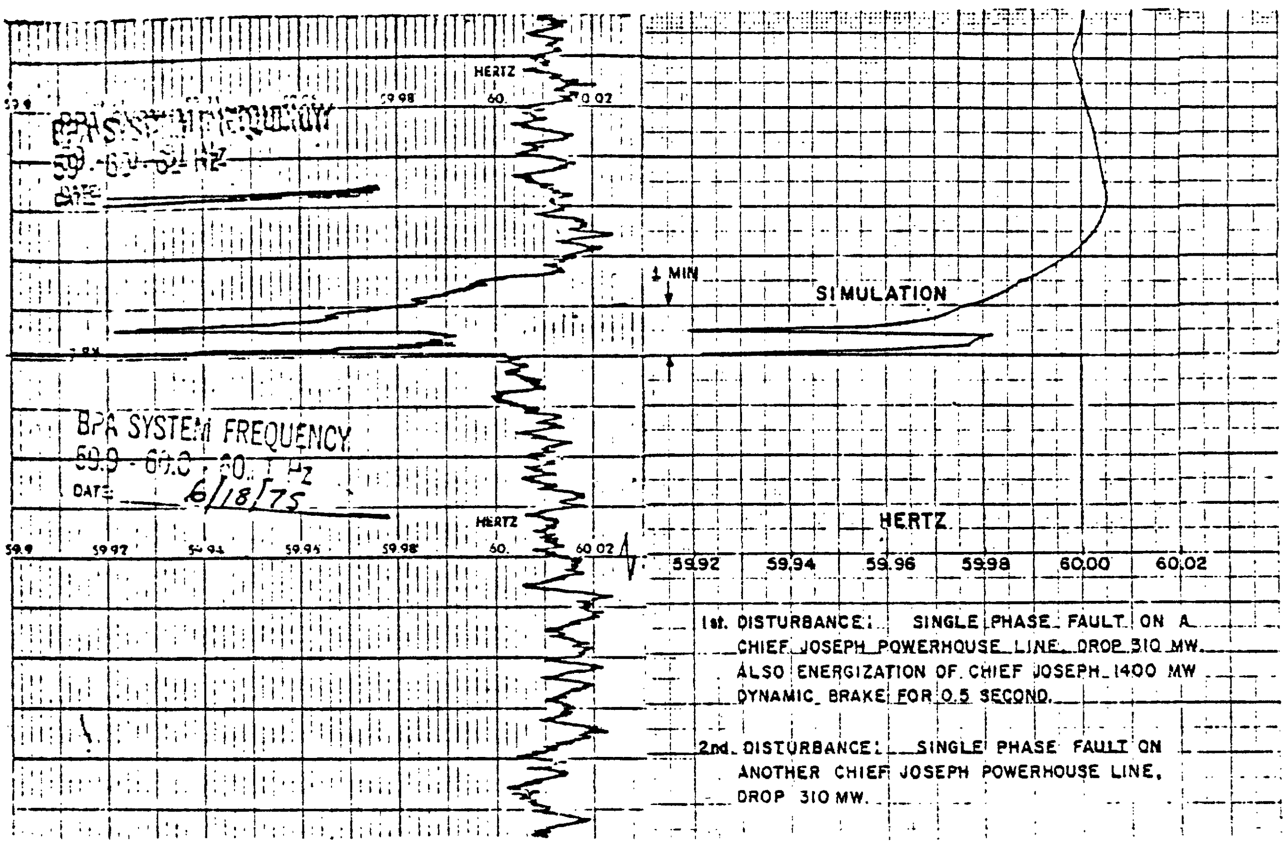

Figure 5.9 Comparison of actual and simulated system frequency for June 18, 1975 disturbance

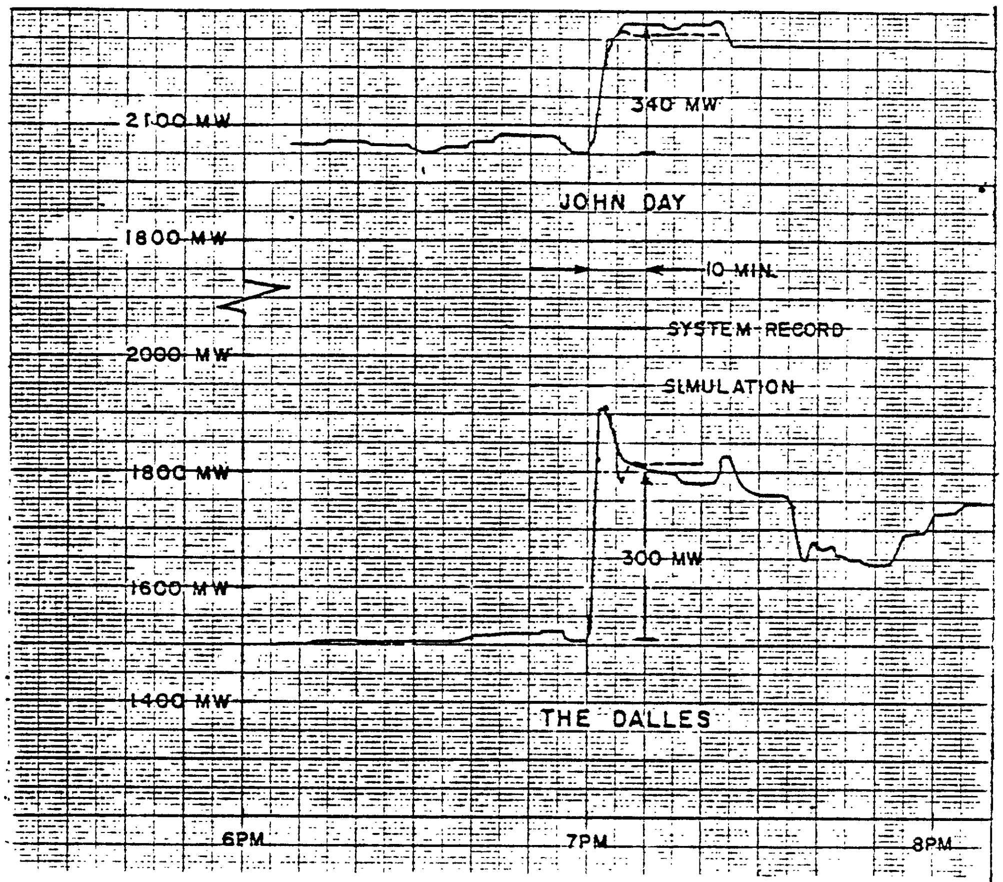

Figure 5.10 Comparison of actual and simulated response of The Dalles and John Day powerplant for June 18, 1975 disturbance

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5.5 Frequency-Adaptive Power-Energy Reschedulers (FAPER's)

5.5.1. The Context

Fluctuating imbalances between generated and consumed power in a power system directly lead to fluctuations of system frequency. (The reasons for this relationship have been described in an elementary way in the section on Generation Frequency Control.) In normal operation of typical systems, these frequency fluctuations remain within 0.01-0.02 Hz of 60 Hz, while immediately following a large disturbance it is possible for system frequency to deviate by as much as 0.1 Hz from 60 Hz. (It must be noted that deviations of no more than 0.3 Hz can lead to damaged turbine blades, etc.)

Power plants operate most efficiently if allowed to generate a steady output. One would especially like to release large utility power plants from the tasks of tracking load variations and of adjusting their generation to accommodate variations in the outputs of other sources of generation. Several techniques have been proposed for so-called "supply management" and "load management," with the objective of, among other things, allowing generation to be maintained at more nearly steady levels. (See [1] for a good survey of this subject, and [2] for a less detailed sketch of the load management area.)

<u>Supply</u> management is, at present, largely restricted to energy storage via pumped-storage hydroelectric plants. Such a plant consists of a reversible flow pump/turbine unit that can use any excess system generation to pump water up to a storage reservoir and subsequently, when system load increases, use this stored water to generate power that is repaid to the system at a cost in overall efficiency.

Load management schemes have primarily concentrated on so-called energy demand loads, such as water or space heating. These loads demand a fixed total energy over an interval of time, but place few constraints on how the delivery of energy is distributed over the interval. They are thus amenable to management without particular hardship to the customer. (Such loads may be contrasted with power demand loads, for example lighting, traction motors, etc., where the demand is for a specified instantaneous power, not an average power as with energy demand loads.) The control mechanisms for such loads have been classified, see [1], as being either direct or indirect controls.

Direct control refers to schemes where the utility directly manipulates the load. This may be carried out via pre-set clocks at the load end, or by "ripple control" signals impressed on the power lines and thereby transmitted to loads, or by radio signals, telephone links, etc. These schemes are typically used in conjunction with specially designed energy demand loads such as electric storage heaters. (It is worth noting that this sort of direct control is practiced far more routinely and extensively in Europe and Australia than in the United States.) Outside of the clock-controlled scheme above, direct control methods such as ripple control can potentially form the basis for turning the power system into "a closed-loop system, by using a computer...to monitor the network status via hardline connections to the appropriate monitoring points in the network, and to initiate automatically the transmission of the appropriate commands." [2] The present conception of direct control is still, however, that of a means of smoothing out slow demand variations. (For example, storage heaters are typically heated during the night-time off-peak period, and the heat is then released as needed during the day.) The exception to this occurs when the system is in an abnormal condition, in which case interruptible loads may be signalled to turn off. In more extreme straits, under-frequency relays, which sense the fall in frequency that accompanies loss of generation, may trip and shed blocks of load.

Indirect control refers to load management via methods such as time-of-day pricing or other economic incentives, or by regulation. It exists in various forms in the United States. The aim, however, is still the smoothing of slow and predictable variations in demand.

One of the key contributions of the Homeostatic Power System framework is the fact that it makes the conceptual transition to rapidly-varying, closed-loop, distributed decision-making and control. The indirect control methods described above thereby evolve into the concept of an energy marketplace, with spot prices varying adaptively in time and exerting indirect control on both distributed supply and demand, and with customers becoming more involved and more sophisticated in their relationship with the rest of the system. Along with this, the communication and hardware aspects of direct control schemes evolve into those needed for implementing the energy marketplace. And finally, the concept of direct control is itself modified; rather than requiring the utility to sense system conditions and command appropriate responses, one attempts to make loads themselves sensitive to system conditions and able to contribute autonomously to the required control action. This latter type of load response is exemplified by the Frequency-Adaptive Power-Energy Rescheduler, or FAPER.

5.5.2. FAPER Operation

The operation of one suggested FAPER design, as described in the accompanying paper on Homeostatic Utility Control, is reviewed here. Other designs are possible and will be mentioned. The FAPER presented below is intended for operation on deadband type control systems, for example room heaters. In normal operation, a heater is on until the room temperature reaches some upper threshold, denoted by T_{max}; at this point the heater turns off. The room cools gradually as a result of natural heat loss, and eventually the temperature falls to some lower threshold, T_{min}, at which time the heater is switched back on.

The idea now is to make such units frequency responsive, in the following sense. A drop in system frequency is indicative of excess load on the system and one would like to therefore encourage heaters that are currently on to turn off. This may be done by lowering the upper threshold below T_{max} by an amount that is a direct function of the instantaneous frequency deficit. On the other hand, a rise in system frequency corresponds to excess generation, so, to encourage units that are off to turn on, one could raise the lower threshold from T_{min} by an amount that is a direct function of the instantaneous frequency excess. This scheme is represented by the relationship graphed in Figure 5.11, which shows how the upper and lower thresholds, T_u and T_l respectively, will vary with the frequency perturbation Δf ; a positive of Δf denotes a frequency excess, a negative value denotes a deficit.

Many other schemes can be concocted. For example, rather than altering the switching levels one could, if there was a frequency deficit, cause a heater that had arrived at T_{min} to wait a time

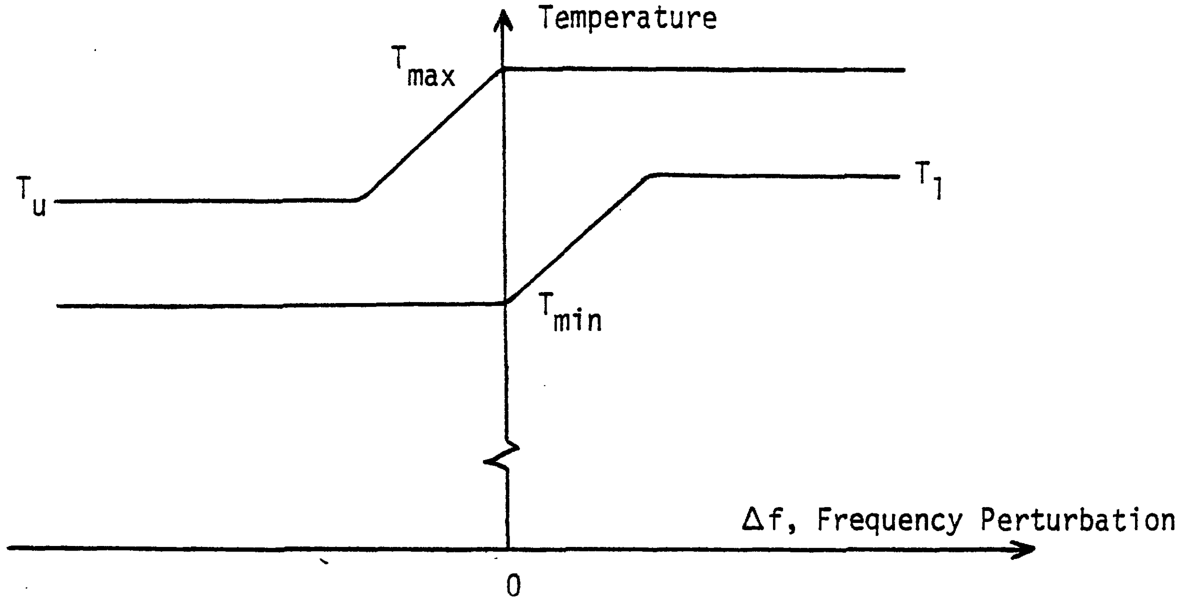

Figure 5.11

proportional to the deficit before switching on (with a similar action at T_{max} for a frequency excess). A more significant change would be to make the switching levels shift in response to past as well as present values of frequency perturbation. The scheme to be focused on here is sufficiently interesting, however, to illustrate the basic ideas, and also to bring out the difficulties associated with the analysis of a) individual FAPER's, b) large numbers of FAPER's, and c) the effect of FAPER's on power system behavior. (It has the added feature that it never allows temperature to go outside the range T_{min} to T_{max} that the customer has accepted as tolerable prior to the insertion of the FAPER logic.)

Before going on to discuss a) to c) above in slightly greater detail, it is important to recall that there are two basic functions that one would like an ensemble of FAPER-controlled units to carry out. The first is a governor/AGC function, intended to provide responsive behavior to the small and rapid frequency fluctuations that occur in normal operation, and the second is a reserve function that is intended to help in cases of generation loss. It will be necessary to examine any proposed FAPER scheme on both counts. Even the scheme of Figure 5.11 simple as it seems, is not really completely specified from this point of view until Δf , the "frequency perturbation," is more completely specified: do we measure the perturbation from the short-term average frequency, or from the long-term average, or from 60 Hz, or from some other frequency determined by time-error corrections in progress, or...?

a) Individual FAPER's. In principle, if one was given the temperature and state (i.e. on/off) of a given unit at some instant, and if the ensuing frequency-perturbation trajectory was known, one could (on using FAPER control logic specified, for example, as in Figure 5.11) determine completely the ensuing behavior of the unit. This is illustrated in Figure 5.12, for the case of a unit that is assumed to have

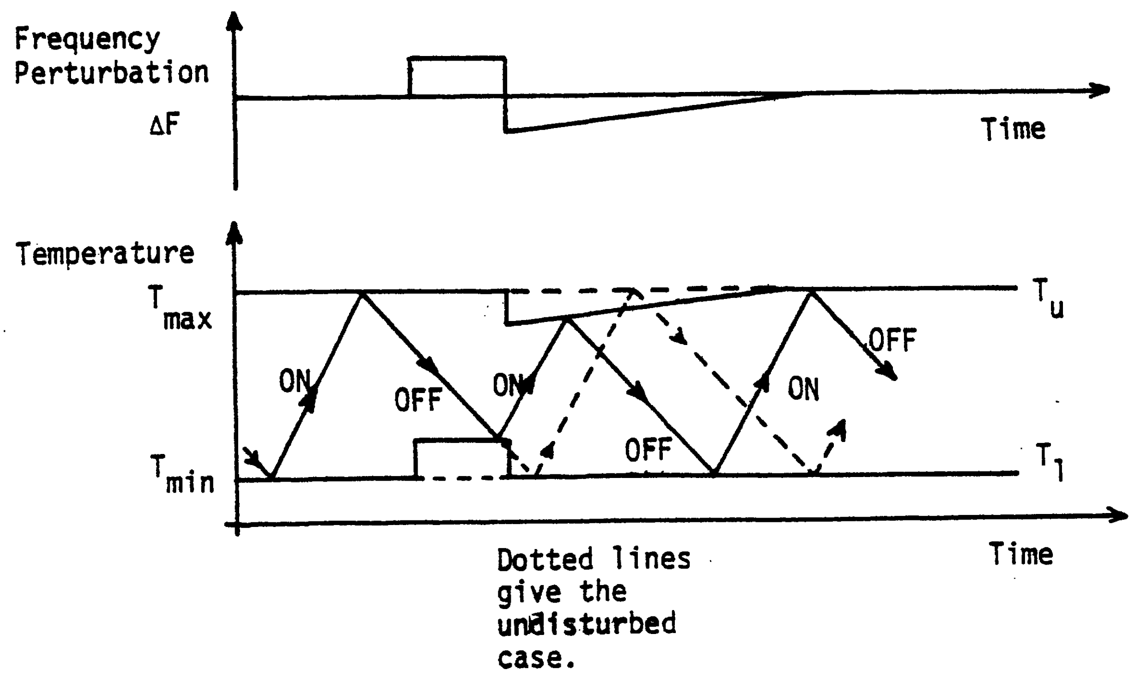

Figure 5.12

linear heating and cooling characteristics. The difficulty with this, however, is that the thermostat itself is a highly nonlinear device, so that the response of the unit to one frequency-perturbation trajectory gives little or no information regarding the response to other trajectories! Techniques have been developed in the literature on nonlinear systems for approximate analysis of such so-called "hysteric two-state" systems, for special classes of input trajectories, and it remains to be seen whether these methods are useful in the present context. Two classes of frequency-perturbation trajectories that are of interest are: i) small and rapid random signals, corresponding to signals requiring governor/AGC action, and ii) larger, sustained changes corresponding to loss of generation.

b) Collections of FAPER's. The logic of Figure 5.11 implicitly relies on there being a large number of FAPER-controlled units, in order that the desired form of response occurs. To see this, note that a particular unit may be unaffected by a short-duration frequency perturbation that occurs when the unit is in the middle of its heating range. Given a large number of independent units, however, and assuming they are randomly distributed over their ranges, it is likely that there will be a considerable number that are near their switching thresholds, and hence immediately responsive to a frequency perturbation.

As mentioned in the previous section, the general analysis of a single unit is already rather hard. The analysis of collections of such units is more involved in some respects, but there are simplifications that can arise from the fact that the macroscopic characteristics may not be too dependent on the details of operation of the individual units. Furthermore, it now may become possible to make justifiable assumptions regarding, for example, the random distribution of units over their working ranges, and to perhaps analyze the collection statistically rather than deterministically.

An idea of the typical factors one has to contend with may be brought out as follows. If at some time it is assumed that the units are uniformly distributed over their ranges, and a sudden drop in frequency occurs, it may be seen from Figures 5.11 and 5.12 that all units in a certain neighborhood of the upper limit will turn off at the same time. This creates a "bunching" of the units, so that they are no longer uniformly distributed. It is reasonable to expect that the units will eventually "forget" the original disturbance, as a result of random jitters in their heating and cooling curves, and will end up (in the absence of further frequency distrubances) being uniformly distributed once more. It is evident that one needs to specify more accurately the nature (timescales, magnitude, etc.) of expected frequency perturbations, to characterize their macroscopic effects, to understand and model more precisely the re-randomization process, etc.

c) Effects of FAPER's on the System. The discussion up to now has actually centered on the "open-loop" behavior of individual FAPER's and of collections of them, with frequency perturbations taken as some externally specified function of time. In fact, however, the frequency perturbations are of course themselves affected by the load perturbations that result from FAPER operation, so the problem that need ultimately to be considered is the "closed-loop" configuration of Figure 5.13.

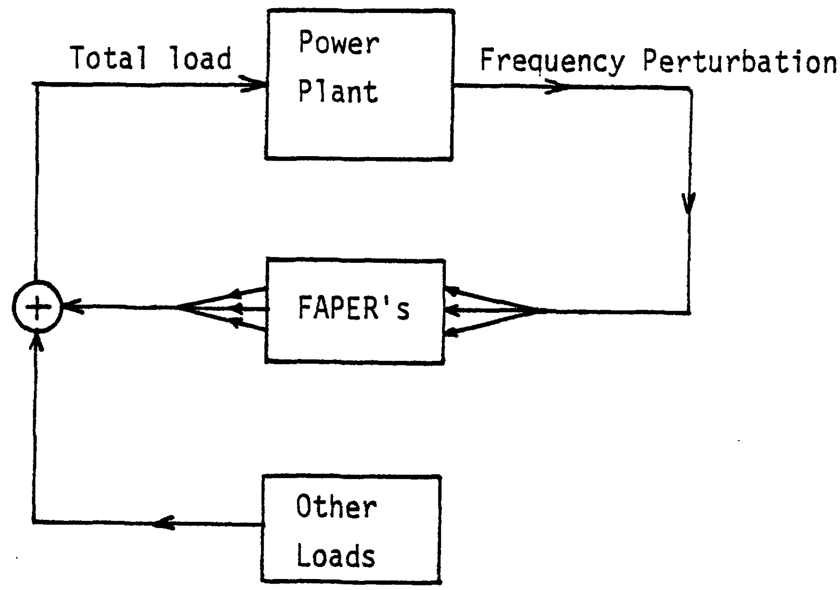

Figure 5.13

5.5.3 FAPER Economics

The justifications for FAPER installations must lie in a reduction of overall power system costs. As indicated previously FAPERs can serve useful functions in the reduction of spinning reserve requirements and in the reduction of AGC/governor action of central station power plants.

The economic value of reducing spinning reserve requirements can be estimated in a relatively straight forward fashion for any given system. The numerical values themselves will vary widely depending on the system itself and, often, with time of day.

The economic value of reducing the AGC/governor costs required for the central station power plant is much more difficult to quantify.

Reference 3 lists such reductions as one of the motivations for installing new power system control centers which Ref. 4 discusses. The importance of these costs however neither reference is able to provide numerically.

5.5.4 Concluding Remarks

Efforts at the time of this writing are directed towards simulation of the configurations a) to c) above, with a view to obtaining a better feel for the dynamics of FAPER operation, and thereby being led to plausible assumptions that will enable some useful analysis to be carried out. Much hard research remains to be done.

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Power

Power systems '2000': hierarchical control strategies

Multilevel controls and home minis will enable utilities to buy and sell power at 'real time' rates determined by supply and demand

Because more devices for customer generation and storage of energy will be in operation by the year 2000, the customer—residential, commercial, or industrial—will be considered a vital part of the electric power systems of the future. New types of central-station generation, storage, transmission, and distribution will be available, and there will be basic changes in the total energy picture as well.

Control systems adapt to changing technology and public needs. Capital and fuel costs will continue to rise rapidly, which will justify the expenditure of more and more money to improve the economics of power system operation. Other factors that will influence future changes will include the following:

- New types of central-station generation, storage, and transmission/distribution systems will be installed. Environmental right-of-way/siting concerns will make it necessary to demand ever-higher degrees of performance for installed facilities. Thus, future control systems will be called on to handle ever-more-complex problems under increasingly stringent and demanding conditions.
- The future will see the introduction of more customer generation and/or energy storage, including solar heating, cogeneration, and eventually solar photovoltaic. These local devices will place new demands on control systems.
- Public attitudes toward power will change in the future. The energy marketplace that will come into operation will change the basic nature of future control strategies.
- Demand depends on weather. Introduction of solar, wind generation, wet/dry cooling, etc., will greatly increase weather dependence. Environmental considerations of air and thermal pollution will increase and add even more weather dependence. Very sophisticated systems for monitoring the weather and environment will be integrated into future control systems along with models for forecasting weather and environmental impacts.
- Research on behavior of power plants, loads, etc., will make it possible to have mathematical models that approximate actual behavior at least some of the time. Future control systems will use these mathematical models in real-time operation.
- Computing and communication are among the few things left in our society that are decreasing in cost. Furthermore, data-network communications and mini- and microcomputer technology are evolving at a rate that parallels the needs of electric power systems. Future control systems will exploit this technology extensively.

This writer's prediction of the control systems of 2000 is based on the foregoing predictions of influencing factors. The implications are that the future will see more sophisticated control systems involving many sensors and computers, all interconnected via extensive data networks. The need exists, the technology is available, and the dividends from its use will justify the expense.

Already an electric power system is the largest physically interconnected system man has invented. The only way to control such a complex network is to break it down into levels defined by the issues of concern (Fig. 1). The elements at Level 0 are the direct-acting devices for automatic local control—the relays, governors, regulators, firing controls, thermostats, etc. For higher elements (I, II, and III), controls may be viewed as a combination of information-processing and decision-making systems (Fig. 2).

In brief, the controllers at Level 0 receive the actual sensor signals from the various physical devices and use a control law to determine the signals to be sent to control actuators. Level III makes no decisions; Level II decides on goals and targets; Level I decides on such matters as set points and gains for the control laws; and Level 0 uses these control laws to generate control signals.

In terms of information flows, Level I receives measurements from Level 0 and sends models of the Level I elements to Level II. Level I can also receive models from Level II about other nearby Level I elements. Level II trades models with Level III in a similar fashion.

Control hardware/software

Almost all of the Level 0 control logic will be implemented on digital microcomputers. In many cases the sensors themselves will furnish the digital outputs and the actuating devices will accept digital inputs. This digital structure will make communication between Level 0 controllers and higher-level controllers easy to implement. In a given power plant, the same basic microcomputer control packages will often be used for both voltage regulators and boiler-firing controls, even though the control laws themselves are radically different.

Control functions at Level I will be implemented by human operators teamed with digital computers. Prepackaged control rooms with minicomputers and cathode-ray tubes for display will be used for similar elements, including fossil plants, nuclear plants, and substations. Residential customers and small businesses will be able to choose from a wide spectrum of standardized microcomputer display systems, depending on their own needs and preferences. (By the year 2000, relative af-

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fluence may be determined as much by the size of a family's home computer as by the size of their house. In both size and sophistication, the control rooms of some large industrial customers will rival those of the utilities themselves.)

Control systems for Levels II and III will also be based on computer/human teams. Large wall displays driven by digital computers will be used in addition to multiple CRTs. In some Level II installations, parallel computation will be used. Control rooms for Levels II and III will be composed of standardized hardware and software modules tailored to specific needs.

The vast amount of digital communication will be carried out through a variety of channels, depending on the application, function, and geographic region. In some power plants and substations, optical fibers will be used. The power lines themselves will provide communication with most two-way utility customers; other roles will be played by radio, microwaves, leased telephone lines, and possibly even satellites. Because of the extensive intercomputer communication required and the massive amounts of data involved, the message flow itself will require sophisticated control logic.

Vendors will be competing for both utility and consumer markets by offering a variety of hardware/software packages. To minimize compatibility problems, basic hardware and software will be standardized along with data formats and definitions of terms.

Models

There are two kinds of models used in controlling electric power systems. Mathematical models include algebraic and differential equations, cost curves, stochastic processes, look-up tables, and optimization logic, all of which describe the relationship between system variables and the operating controls. They are used today in the off-line design of controllers. Human operators also use "models"—though not mathematical formulas—of how they think the system will behave at different states of operation.

Today, real-time operation and control are based largely on such "models," but in the future these will be supplemented, to a large extent, by equations, so that each model's strengths and weaknesses will be complemented by the other. In fact, the primary purpose of the information-processing systems is the maintenance of these models.

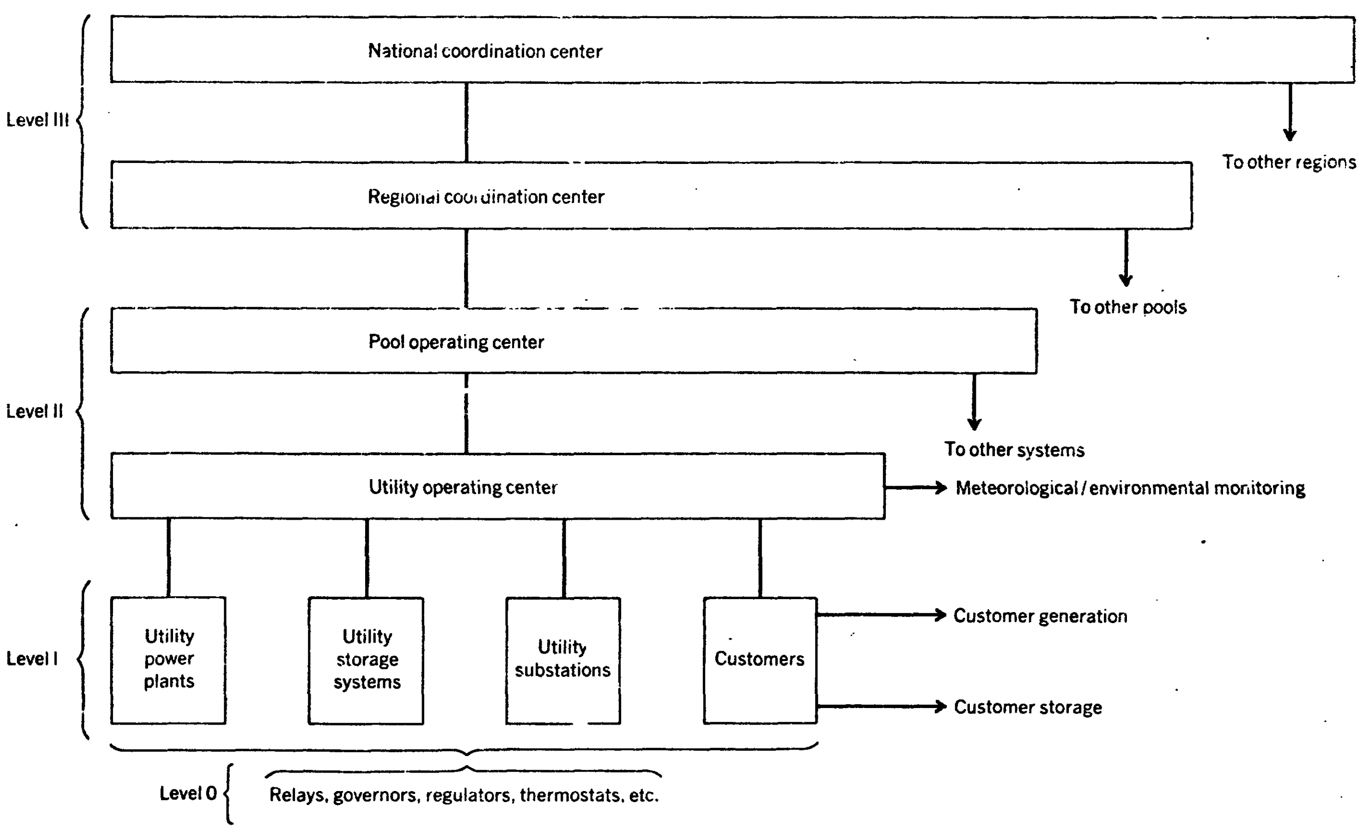
Extensive use will be made of mathematical models for external equivalents—approximations of the rest of the power system ("the outside world") as seen from a particular element or group of elements of concern. This will make possible a high degree of decentralized decision making.

Control functions

The kind of control employed for the main elements will depend on two things: the system's operating state—normal, alert, emergency, in extremis, restorative (see "Operating under stress and strain," Mar. p. 48); and the status of the system models—valid, invalid, accuracy measures. Decision-making systems that use on-line mathematical models obviously will modify their decisions whenever validity or accuracy is in doubt. Algorithms to detect and identify changes in the system and the status of its models will be in continuous operation.

Electric utilities will operate many types of power plants, but fossil and nuclear will predominate, though

[1] Hierarchical decomposition into a multilevel strategy is essential for power-system control. Level III facilitates the exchange of information and/or models to provide interarea coordination. Level II determines goals and targets that Level I uses to specify control-law parameters (gains, time constants, set points). These control laws are used at Level 0 to provide actuating signals.



The energy marketplace

The utility's role in furnishing power, the customer's attitude toward the use of power, and the nature of electric power control systems are closely coupled and interrelated. A major shift in the relationships that exist among these three will occur by 2000 with the establishment of the "energy marketplace."

Today the relationship between customer and utility is one of master to slave. The customer is the master who demands power from the utility, his slave. The slave is expected to provide as much power as the master wants, any time the master wants it. The control systems reflect this relationship because they are designed to help the slave do everything possible to meet the master's demands. When control systems push the slave beyond its limits, the slave collapses and the master is left on his own. Unfortunately, in our present society, the customer has become so dependent on the utility that the master is not able to function without the slave.

But by 2000, the relationships between the customer, the utility, and the control systems will have changed significantly. By then, the utilities and customers will be equals who deal with each other through the energy marketplace.

The utility's generation and storage systems will offer power for sale to the customers, and customers will buy most of their power from the utilities. However, some customers will generate their own power and offer any extra for sale. All of these transactions will take place via an energy marketplace, which will consist of the transmission/distribution grid that does the "physical" distribution, and the control systems that enable the "market transactions" to take place. Thus, in addition to providing central-station generation and storage facilities, utilities will also maintain the energy-marketplace mechanism.

The energy-marketplace economics will operate both long-term contracts (where the rate is prespecified for one to two years in advance and depends on time of day, season of year, energy use, and peak demand) and spot-price rates (which are not specified in advance, and depend on actual market conditions as determined by demand, plant outages, and weather, on an hour-by-hour basis). There will be long-term contracts and spot contracts for both buying from and selling to the grid (marketplace). There will also be the interruptible versions of both kinds of rates. Interruptible rates for buying power will be lower because the utility has bought—by applying lower rates—the right to disconnect part of the customer's load when it chooses.

The ability to build sophisticated control-communication systems is necessary for the energy-marketplace concept to work, and the evolution of that concept will have a major impact on the control systems. Relative to blackouts, the key change is in the ability of the utility to exercise load control ("soft" load control via the economics of spot pricing or "hard" load control via the disconnecting of interruptibles).

there will be wide variations in fossil type, methods of cooling, air-pollution controls, and so on. Of course, there will be wind, solar, and hydro plants as well. The types of control actions available will depend on the specific nature of the plant and the system to which it is connected. (See "Hardware and software for system protection," May, p. 40.)

Information processing will require up-to-date models for plant economics, plant dynamics, and equipment capabilities. External-equivalent models for dynamic response will be developed by combining real measurements from Levels 0 and I for information sent from Level II.

The decision-making system will have many tasks. During normal operations, computers will take over plant startup, shutdown, and control, and optimize fuel consumption. The control laws for Level 0 will be continually readjusted by human/computer teams as a function of changing conditions so they can react in the most appropriate fashion if emergency conditions arise—thus providing coordinated control for the entire plant. Generally, the decision-making system will attempt to achieve goals and targets sent to it from Level II, but it will proceed on its own when no such instructions are provided.

The electric utilities will use a variety of energy-storage devices such as pumped hydro, compressed gas, thermal, magnetic field, and batteries, all controlled by procedures very similar to the ones used for power plants—adapted, naturally, for the specific device involved. In most cases, the controllers for storage systems will be simpler than for power plants.

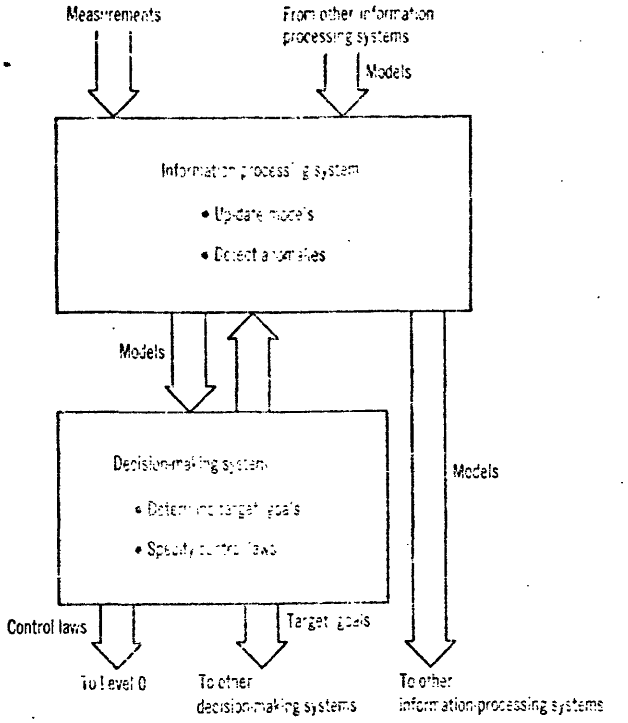
The term "substation control" refers to relaying, voltage control, and load-shedding functions but the nature of that control varies with the voltage levels. (Only transmission and distribution voltage levels are discussed here.) Information processing will handle data before sending them to Level II, and will also detect anomalies that occur either in substation or Level 0 control loops. The models used for the load's demand and response characteristics will be updated continuously and supplied both to Level II and to the substation's own decision-making system, where they will be used to implement instructions that are furnished by Level II. Distribution substations will monitor line and customer outages for Level II, so that repair crews can be dispatched with greater efficiency.

Substation decision making will be concerned primarily with coordinating Level 0 relay logic with the conditions and needs that exist in the overall network. Level 0 relays will control circuit breakers, and in some cases reactances and resistances, for both equipment protection and dynamic control. Most of the instructions will come from Level II, though transmission substations with ac/dc converters will also have logic for scheduling power flows.

By locating the Level I system remotely, one control room will be able to cover multiple substations and even storage. These controls may even be located on the same site as some controls for Level II.

Customers

In the next 20 years the relationship between the utility and its customers will change dramatically. The interaction and cooperation between utilities and their customers



[2] Higher-level controllers perform two separate functions. Information processing converts all available information (measurement and models from other sources) into a form that decision making uses to specify goals and control laws.

will be extensive, with both sides buying and selling energy (see the box on facing page).

The extreme diversity among types of customers makes it impractical to try to cover the whole spectrum of customer control functions. Instead, a single-family residential customer is used as an example. This family is arbitrarily assumed to have photovoltaic solar cells, a heat pump with thermal storage for space conditioning, and the usual collection of cooking, cleaning, and recreational electric devices. The family is also assumed to have chosen to buy a microcomputer control system and to have signed a spot-price contract with interruptible rights with the utility.

Control will be handled by members of the family and the microcomputer. The information-processing system in the microcomputer will maintain mathematical models of the family's energy-usage patterns, energy storage, etc. The decision-making system in the microcomputer will determine a strategy for the best energy use by considering issues such as whether to buy or sell power from the grid, whether to store energy, and whether to run certain basic appliances.

These decisions will be based on the family's own energy-use model, the spot price of electricity, and the predicted weather. Under normal conditions, the family members themselves are the decision-makers for such devices as lights and television. Some families may choose to have a continuous display showing how much their use of electricity is costing them.

The utility's Level II system will control the family's energy use in different ways when there are problems of an imbalance between supply and demand. Variations in spot price will provide "soft" load control. However, when necessary for blackout prevention, the utility's Level II will command the family microcomputer to readjust load-dropping logic (underfrequency, etc.) and/or

Anatomy of a blackout: 2001

It is a Friday in July 2001. A medium-sized Midwestern city has two utility-owned fossil-fuel plants and energy-storage units within its boundaries and is further fed by five transmission lines.

8:00 a.m. The weather forecast is good. Using dispatch strategy of minimum cost, the utility delivers most of the city's power via the transmission lines. One fossil plant is partially loaded and the second turned off. The plan is to use up all stored energy by the end of the day and replace it on the weekend. For the weather that is forecast, neither fossil plant can operate over 50 percent of its capacity because of environmental constraints.

10:00 a.m. Weather forecast changes to possible storms in afternoon and evening. The utility decides to stop using energy from storage.

3:00 p.m. Thunderstorms and tornado warnings are given. The utility starts to increase the amount of energy it has stored in the city and turns on the second fossil plant to its environmental limit. The control law of the relays in the switchyards and the governors, exciters, etc., at the power plants are changed to adapt to the new pattern of generation and storage. Some of the customers hear the storm warnings and decide to fill up their own storage, creating a further increase in demand.

4:00 p.m. A major thunderstorm comes through with multiple lightning strikes on transmission lines. Most strokes result in routine, automatic clearing and reclosure. Faulty relay action near one steam plant causes a delay in fault clearing but fast valving prevents loss of synchronization. A stuck breaker at the other fossil plant causes it to lose synchronism, but it trips to house load and is resynchronized within five minutes. The necessary energy to cover the lost output is obtained from the transmission grid.

4:15 p.m. The changing weather patterns have removed environmental constraints on the fossil units' output. Both are increased to maximum output.

4:30 p.m. Tornados take out two of the five transmission lines. One of the remaining lines is overloaded. Generation patterns outside the city are rescheduled to remove the overload within five minutes.

5:00 p.m. A second line of tornados comes through and takes out two more transmission lines. The last line is heavily overloaded. The spot-price rates at which the utility buys and sells power from its customers are set very high to increase customer generation and decrease load. Some customers do decide to sell. Others continue to fill their own storage systems. The line overload is removed in 20 minutes.

7:00 p.m. The last transmission line is hit by a small plane. The city is now an electrical island. Frequency decay is stopped by dropping more interruptible loads and by the use of energy from storage.

8:00 p.m. Faulty computer logic allows a transformer to overload and burn out. This isolates one of the fossil plants. All interruptible load is disconnected. Rotating blackout is established throughout the city. Essential services are still served 100 percent of the time.

9:00 p.m. Operator error trips out the one remaining fossil plant. The city is blacked out in the technical sense: The transmission/distribution system within the city is no longer energized. However, there is no blackout in a social sense because essential services—such as street lighting and elevators—are still covered from auxiliary units and/or local storage. Many customers still have power for essentials, either from their own storage or from auxiliary generation systems.

to shed load directly. The exact logic will depend on the details of the interruptible-load part of the contract between the family and the utility.

Pool utility operating centers

The pool operating centers and utility operating centers of Fig. 1 will play different relative roles in different parts of the country. Here they will be discussed as a single entity, the "pool utility operating center." Many utilities will also maintain separate operating centers for transmission and/or distribution. These may also be viewed as part of the pool utility operating center. Thus, the pool functions discussed here usually will not all be in one physical location.

The information-processing system will maintain up-to-date mathematical models of almost all the types summarized in Table I. The Level II versions of plant dynamics, equipment protection, and customer load models will be simplified equivalents (or aggregations) of the more detailed models that are maintained at Level I. Other models, including system economics, system dynamics, and transmission/distribution, will exist only at Level II. These models will provide information to help Level I elements develop external-equivalent models. The information-processing system of Level II will also maintain external-equivalent models of the outside world as seen from Level II.

Most pool utility operating centers will have some outside organization maintain and run the weather/meteorological model. Outputs from the weather model will serve as inputs to many other models, such as solar generation, demand, environmental impact, and security. Different meteorological variables will be used for the various applications. Weather forecasts will also be made available to those customers who want to use such information in determining their own energy-use strategy.

Figure 1 implies that the environmental monitoring will feed directly into the Level II information-processing system. Actually, in some parts of the country, such monitoring and the associated environmental impact modeling will be done at Level I.

The decision making at Level II will be responsible for smooth operation of the energy marketplace. It will determine the targets/goals for utility power plants and storage devices to minimize operating costs subject to constraints. Many of the economic decision-making functions will be conceptually similar to those of today (see "System security: the computer's role," June, p. 43). However, the constraints, cost models, etc., will be much more sophisticated and complex, involving weather-dependent demand, generation, environmental impact, and security constraints. Security constraints will include system dynamics explicitly, via appropriate mathematical models.

In addition, a new phenomenon, one that has no analogue in existing systems, will also occur—the feedback effect on demand that spot prices will have. The optimization will be done in the context of probabilistic (stochastic) mathematics to represent more accurately the many uncertainties involved.

The "antiblackout" aspect of Level II decision making will depend on the state of the system. Level II's role for fast transients (faults, transient stability) will be to help the Level I decision-making system set the control laws of the Level 0 automatic controllers before the transient

Some controversial issues

Agreement on all aspects of the future of power system control does not exist. The relative roles of human operators and computers is a controversial topic. Arguments in favor of increased use of computers to replace human operators can be based on:

- The inability of human operators to comprehend the complexity of power systems fast enough to be effective
- The fallibility of humans (operators make mistakes)
- The availability and low cost of computer hardware

Arguments in favor of an increased importance of the human operator can be based on

- A computer's ability to reduce information to a form that human operators can comprehend
- The fallibility of humans (computer programmers and designers make mistakes)
- The fallibility of computers
- The value of human insight/intuition
- The value of extensive simulator training

This writer thinks the second set of arguments will prevail and that the role of human operators will increase in importance. Extensive training/simulation facilities will be routinely used.

Everyone agrees with the need for some hierarchical control structure. It is impractical to be completely centralized (all control at Level III) or completely decentralized (no control above Level 0 or I). However, the relative amount and type of centralization are controversial. Arguments in favor of centralization can be based on such issues as

- Reduced fuel costs because of more coordinated operation
- Improved dynamic control and security because more of the overall system is being controlled from one point
- The availability of communication-computer hardware for centralized control (except for some fast actions such as fault clearing)

Arguments in favor of as much decentralization as possible can be based on such issues as

- Insignificance of economic-dynamic improvements obtainable from centralization
- Fear of major catastrophe due to failure of centralized control
- Belief that centralized controllers lose contact with local needs and problems
- Existing institutional constraints (different utilities in different states, etc.)

The writer thinks the decentralized philosophy will prevail.

A third controversial issue centers on the types of computers to be used. Two major competitions are

- Digital vs. hybrid
- Many small digital vs. a few large digital

Hybrid computers can solve particular problems of power system dynamics very efficiently and rapidly.

Digital computers are more versatile. Using many small digital computers enables distributed computation, parallel processing, and greater reliability. Big digital computers are more versatile, easier to program, and don't waste time talking to each other. The writer thinks that the "many small digital computers" approach will prevail.

begins. For long-term dynamics and dynamic-stability transients, the decision-making system will operate during the transient. The ability of the Level II decision-making system to drop interruptible load will change the philosophy underlying the choice of control laws.

Level II's ability to deal with system restoration following outages will be greatly increased (relative to today), especially at the distribution-system level. The dispatch of repair crews will be based on detailed models, including weather conditions and outage patterns of the distribution lines of the customers.

The digital computers of a Level II pool utility operating center will talk directly with the various Level I digital computers. The amount of communication and Level II computing that will be done will be massive compared with the amount done by today's systems. As discussed previously, the human operators will be responsible for the development and maintenance of many diverse mathematical models. During normal conditions, digital computers will use these mathematical models to make decisions that will usually be implemented automatically, with the operators providing supervision and making risk-tradeoff decisions. When the system is in real trouble, the operators will make many crucial decisions from lists of alternate possible actions and their implications, as provided by computers.

Coordination centers

Regional coordination centers will do no decision making. Their primary information-processing role will be that of facilitating information exchange between Level II control systems.

A regional coordination center will act as an information clearinghouse. It will gather models on both present and future costs from Level II and share this information so the Level II systems can decide whether to buy or sell power, how to coordinate reserve allocation, etc. The regional coordination centers will have the responsibility of determining "wheeling costs" (the costs associated with transmitting power from one region to another when portions of the power go through a third region).

For dynamic control and security issues, regional coordination centers will gather mathematical models for the portion of the entire interconnected system outside of the particular Level II system. A regional coordination center will also have the responsibility for regional security monitoring to provide an independent check on system security to supplement checks made at Level II.

Computers at the center will talk directly with the computers of the various Level II control systems. Supervisory operation of the system will be the prime responsibility of the human operators.

A national coordination center will coordinate the various regional coordination centers. Conceptually, the relationship between the national center and the regional centers will be similar to the one between the regional centers and the various Level II control systems—information exchange only. This will be accomplished primarily by committee meetings and telephone calls.

I. Mathematical models

- Power plants/storage devices
  - Cost, efficiency, loss models
  - Electrical, magnetic dynamic models
  - Thermal, chemical, mechanical dynamic models
- Equipment protection
  - Mechanical stress models
  - Thermal rating models (weather dependent)
  - Electrical overvoltage models
- Customer
  - Energy-use-pattern models (weather dependent)
  - Energy-storage models
- System economics
  - Cost models
  - Constraint models
  - Shadow prices, incremental-change models
  - Weather-dependent-generation models
- Transmission/distribution models
- System dynamics
  - Transient-stability models
  - Dynamic-stability models
  - Long-term dynamic models
- Weather/meteorological models
- Environmental-impact models (weather dependent)
- Load characteristics
  - Demand models (weather dependent)
  - Voltage, frequency-change-response models
- System-security-index models (weather dependent)

Blackouts in 2000?

Even though sophisticated control systems are already in operation on electric power systems, blackouts occur (see "Anatomy of a blackout," Feb., p. 38, and "Whys and wherefores of power system blackouts," Apr., p. 36). Assuming that the control systems used in 2000 will be even more sophisticated, a key question is, "Will there still be blackouts?" The answer depends on which definition of the term blackout is used. The technical definition is that a blackout has occurred when power is not available from portions of the transmission/distribution grid. The societal definition is that a blackout exists when a lack of power incapacitates critical functions and results in major social disruptions.

Blackouts will continue to exist, if the technical definition is used. There is simply no way to build a system that is 100 percent reliable. Eventually something will always happen to make it necessary to deenergize some portion of the grid temporarily.

If the societal definition is used, blackouts will not exist in the year 2000. By then the public will have accepted the fact that total blackouts (technical definition) can occur and, therefore, will have provided supplemental energy sources for critical functions. When there is a total blackout (technical definition), enough of these backup sources will work so that major societal interruptions and disturbances will not occur. There is a good chance that by the year 2000 the term blackout (societal definition) will be considered to be a term out of the Dark Ages. ◆

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5.7 Discussion

The major question focusing the discussion of quality of supply pricing and system control was what control mechanisms are available as and/or when system capacity is approached. While spot pricing may assist in reducing demand at such times, it is clear that such pricing systems cannot deal fully with the problem, particularly should it occur in an extremely short time frame. Quality of supply pricing (QOSP) and system control as presented during the discussion are designed to meet the needs of the utility for control of its load at times when system capacity is being approached. Given this central question the key issues around which the discussion focused were:

- the need for quality of supply pricing
- the need for customer participation in frequency and voltage control, and
- the operational feasibility of the system.

Quality of supply pricing was a concept developed to complement spot pricing as discussed earlier. Conceptually it allows the price of electricity to rise more rapidly that economic spot pricing given anticipated higher costs associated with the feasibility of system failure. As such the discussion focused around the complexity of, and the requirement for a QOSP component within Homeostatic Control. It was agreed that a number of mechanisms should be available to the utility system operators under Homeostatic Control, one of which might be the availability of an additional price signal but that at the same time there was reason to have an additional set of options more physical than price which could be applied as well.

The second major set of issues raised during the discussion focused upon the desirability of having the customer participate in decisions concerning frequency and voltage control. Here the discussion centered around the use and advantages of both the Frequency Adaptive Power Energy Rescheduler (FAPER) and upon its theoretical counterpart, the VAPER (Voltage). The discussants concluded that there was considerable advantage in having the customer participate in voltage and frequency control particularly in those applications where this could be done both automatically and in a manner so as not to be seen by the customer himself, as is suggested in the operation of the FAPER.

While there is a desirability in having the customer participate in frequency control, a set of questions were raised concerning the need for a FAPER given that similar devices and interfaces currently exist on the system. The utility systems now have available to them load shedding system which is activated by declines in frequency. One portion of the discussion in answer to this question was that the FAPER allows both an automatic drop in load and a drop in load at the preference of the customer where the cost of load loss would, by definition, be minimized. The consensus was that the FAPER would in fact add to overall system control and could, given relatively large levels of penetration within the system decrease the requirements for spinning reserves.

An additional set of questions and discussion centered around the source of final control for the utility system given the availability of both FAPER type devices and any type of micro-shedding or other scheduling systems that might become available. The consensus of those present was that the utility control room, or a highly centralized point would in the final instance retain control though it was generally felt that the availability of both microshedding devices and devices such as the FAPER would decrease the need for such action.

The third set of issues discussed centered on the question of operational feasibility of the control devices proposed under Homeostatic Control. These included:

- o errors emanating from the system or introduced by the customer
- o system costs
- o microshedding or end-of-line decisions

There will be probably problems concerning monitoring the system as well as following up on any complaints about errors on this system.

There will be also problems with built-in error conditions and erroneous data recovery. These problems are evident in most every new technology. However, one can be sure that new types of complaints that have never been dealt with before will have to be overcome as the system evolves.

System costs were not clearly identified in the presentation. Thus, many participants anticipate the costs of implementing the Homeostatic Control system could be large. On the other hand, since Distribution Automation and Control (DAC) system, two-way communication links, and load control devices such as FAPERs are in place at specific points in today's utility environment, implanting extensions of these systems in a Homeostatic Control environment would have a minimal additional cost associated with it. However, the maintenance costs of dispersed MICs which relay the price to the customer and other communication links could be high.

A component of the Homeostatic control system which was not fully developed with the presentation was that of micro-shedding and other mechanisms which could be available to the utility operator who has reached the end of the line in terms of additional available capacity. Micro-shedding has been suggested by a number of others and therefore cannot be claimed by the developers of Homeostatic Control as being original yet in concept it fits well with the proposed system in that within any industrial facility equipped with a device such as a MIC it wuld be possible to set shedding levels within the processes themselves such that at the control of the utility specific lower priority operations could be shut down in emergency situations to prevent full system failure. Micro-shedding thus becomes a mechanism by which the utility, through in house control devices such as the MIC is able to shed load that has been preselected by the industry thus being highly selective in its impact and on total system efficiency both physical and economic.

SUMMARY

The discussion of Quality of Supply Pricing and Systems control brought out a general consensus concerning the Homeostatic Control concept and that was that the concept itself is a collection of ideas that have been in the minds of others and on the drawing boards and bread boards of other developers. The uniqueness of the system is the fact that they have been brought together in a rationalized system in which the utility and the customer cooperate as they operate against a common objective function, overall system efficiency and cost minimization.

Chapter 6: PROCEEDINGS OF CRITICAL ISSUES PANEL

6.1 Pricing/Economics*

Everyone here appears to be fairly comfortable with the concept of spot pricing. It appears that it would optimize the formula system. Clearly it is not a system that would work for everyone; it probably wouldn't work for most homeowners, at least not in the short term. It would not even work for most industry, but it would work for some. Therefore, we are saying that this would be an elective optional system for those that can take advantage of it. The economist would be particularly comfortable with this approach; it is conceptually the same idea as transfer pricing - an interfirm or intrafirm environment where we are trying to set up a price that maximizes the mutual advantage. It has been well established that in order to implement transfer pricing you have to know the economics of the two entities between which the goods or services are flowing This is what, in essence, is being discussed with Homeostatic Control and spot pricing there has to be communication. If firm B knows firm A's economics, and if he knows his own economics, there should be a way of optimizing the mutual benefits.

The discussion looked at price in terms of what we're going to price, if it's going to be cost related, and if so, what cost should be used.

The discussion shifted to the question of whether to use short term or long term marginal cost. At least for the energy component, the long range replacement cost need to be the relevant number. For the capital, I would think, conventional theory suggests that whether you use short

*Summarized by Theodore Eck.

term or long term, replacement costs depends upon the duration of the transfer relationship.

I am interested in the potential for broadening the theorical consideration of Homeostatic Control and spot pricing which appears to be a micro theoretical development to date. If this market or cost rationalization approach makes sense at a micro level, it should also make sense at a macro level. One of the more serious questions that we have in the general economy is the fact that many fuels are not presently priced at replacement cost, and probably electricity is the greatest offender. With some of the progress that we are making in natural gas (if you really believe that natural gas will be decontrolled in 1985) hopefully natural gas will rise to replacement cost. Oil, as we all know, is going up daily. Certainly we are not as far from replacement cost in oil as we were a year ago it may not take very long, at the rate we're going, to get the price of oil up to replacement cost. With those two basic fuels at replacement cost, the failure of electricity to do likewise presumably would introduce even more serious implications.

Focusing on the market for electricity, if Homeostatic Control and Spot pricing can optimize the relationship between the distributor and the consumer, we can use the same concept to rationalize the relationships of sales between distributors. There is a real misallocation at the present time; why should we not have the same rationale in wheeling price as we have going from distributor to distributor? Why shouldn't we have a wholesale market in which distributors and large industrial buyers all participate. You can envision that discussion we had on the purchase price of self-generated power and one of the things that should relate to also is the selling price of incremental buying with power. You can envision the possibility of a nonregulated market for power, where we have a market-determined price for wholesale power, where the prices are determined and set by its economic use or value. The theoretical discussion carried on during these sessions represents the basic raw material for structuring a non-regulated market. I suggest that we try to progress always in the evolution of a theory, to go from specific to general. I think we have potential for construction of a general equilibrium theory, an optimization theory of energy markets.

I would like to mention several points from the user's view point. Many users are going to want, and maybe even need, fixed prices and readily predictable prices for their equipment and location decisions. Many firms are going to be very uncomfortable and unable to cope with this level of uncertainties. There is a need to accommodate those consumers.

Another group that's going to be nervous includes us, the continuous process industry, refineries, and chemical plants, and so on, that operate pretty much at a fixed rate, 24 hours a day, 365 days a year. We really don't have any significant potential for optimizing under the conditions that have been discussed here, but I guess we would worry that there would be an inclination to set rate schedules that would overcompensate those sectors that need to economize, while we would end up paying 125% or 150% of relevant cost. You might argue that it would be possible to self-generate. But, I caution us not to take self-generation all that seriously, as it is not a viable option for most companies. There are very, very serious questions about reliability, cost and other considerations. We would much prefer to buy steam from power companies rather than go to large industrial cogeneration.

6.2 Customer Response System *

By way of introduction to talking about the customer response issues that were discussed, I think that a mistake was made yesterday when somebody referred to this concept as an "engineer's dream." It is obviously a "microeconomist's dream." Many of us share the notion that having instantaneous spot-prices, always reflecting costs and willingness to pay simultaneously, is something that is conceptually ideal. What we also have seen is a lack of hard data, and a lack of a firm indication of just what are the costs and benefits of Homeostatic Control. The most significant point of discussion on consumer response centered around the determinants of that response. It's not enough to say that electricity costs are rising rapidly and therefore, anything that enables firms and even other consumers to save, is going to be immediately adopted. It is true, that rewards in going to systems of 10-15 years from now, which would be homeostatics (presumably, at least) will be proportional to the cost of electricity. Because electricity is becoming more expensive does not mean that the costs of gaining benefits from a Homeostatic scheme are irrelevant.

The first point that came up in the opening presentation on the customer response panel was, not that electricity costs were rising, but that the costs of computers and chips were decreasing. One important point that came out in response was that dials and switches of ordinary

*Summarized by Lawrence Linden.

plastic and metal is still important and that the chips may become a negligible part of the total system costs.

While there was some discussion of problems and opportunities in the residential sector with reference to water consumption experience. Residences would not be expected to be the first sector, and probably not ultimately the most important sector, to use the Homeostatic system. Residential consumers are much less able to absorb potentially massive amount of information that would be utilized, and be made available on a system such as Homeostatic Control. Another comment that is central is that we just don't have much experience, or real data on what kind of responses, firms, or residences, would have to such a pricing system. There is very little experience that is directly relevant in this case. While you might think of other analogs like water, or maybe even more distantly, other markets where prices are fluctuating we have too little experience to predict the outcome. We can all sit here and discuss how effective such a system would be, but the level of effectiveness depends on how much the customer's behavior is actually changed.

The most important data set discussed on customer response was that presented by Schweppe for NEES. You need to see how many processes could actually be switched. One significant point from this discussion was the fact that you had to look hard to find a firm that had a lot of reschedulable processes, and power consumption. It appeared from the description that all of the parameters needed to be correct for there to be real incentives for process shifting. Are we really talking about something that in the aggregate can be important? There is considerable homework to be done in extrapolating from this data set. On the other hand, there is another way to look at the question, and that is not to keep the consultants and energy laboratory staff employed, but rather to begin to experiment in an industrial/utility environment. Studies are important but what we really need are experiments with the concept. It is hard to imagine Homeostatic Control being adapted all at once. Nevertheless, it has the opportunity that most new technologies face, which is that someone will find it attractive. We may not know who right now, but there are always a few individuals that are imaginative, either utility chairmen, or imaginative regulators. We already know for instance, that there are a number of industrial firms that are doing impressive things in conservation. We know industrial conservation has been extremely effective in the last six years. Some firms will see such rate systems to their advantage and be prepared to try them. One of the things that needs serious consideration is the possibility of finding some innovative firms, a progressive public utility commission and moving forward.

Another point that was raised out of the San Diego experience was that first, such efforts provide additional data, and second, they become points for comparsion. As with any new system like this, it would be a mistake just to compare it with what we're doing now; it should also be compared with other alternatives now also in the conceptual or experimental stages.

A final point that requires comment is the remarkable degree of aggreement on the merits of Homeostatic Control and the lack of discussion on reactions that this concept might arouse if examined by a larger segment of society than represented by this conference. A response one might anticipate is a reaction against the "bad guys" who run these utilities--they could make out like a bandit in a power shortage with the rationing scheme proposed during the discussion. In fact, we have regulatory commissions in part to prevent this type of long-run undercapacity. The participants here do not seem to distrust the utility executives the way you know a lot of the rest of the world out there does. One concern, therefore, is that there are very different ways of looking at Homeostatic Control and that alternative consumer perceptions need to be addressed as a portion of any further thinking if the system is to survive its potential critics. Particularly if such a concept becomes acceptable in the residential sector.

6.3 Regulatory Environment*

The reactions to the discussions of the regulatory environment may be summarized by responding to four questions which reflect the discussion of the last two days. The first is, can homeostatic control be introduced with the existing regulatory framework? The second is, will PURPA help? The third is, are regulators and utility executives able and willing to make the changes? The fourth is, how can the change best be introduced?

Addressing the first question, can homeostatic control be introduced with the existing regulatory framework for a class of customers, or ultimately for more customers? The answer that has been the general consensus of this group would be yes. The legal and conceptual barriers can all be overcome. The first type of barrier, both legal and conceptual, might deal with rates being functional rather than fixed. There is sufficient precedent for functional rates, thus no problem in

*Summarized by Richard Bower.

meeting fair and reasonable standards as conceived by either commissions or courts. A functional rate system, where rates are a function of kilowatt (KW) usage at a moment of time, could be ascceptable as well as a fixed rate system. This is not as significant barrier. The barrier is not with the rate structure per se, but with the revenue requirements associated with it. The problem exists at two extremes. At one extreme there is the problem of a guarantee of income to the utility that might be associated with the rates. One interpretation of this proposal was that the sum of prices times quantity over a year would equal the total cost of the utility company a guaranteed revenue proposal. Were this the case, it would not be acceptable. But as long as Homeostatic Control is a system in which the sum of price times quantity is not equal to the utility's annual cost of the year which would be the case if you used system lambda's, for example, and worked with lambda's or if you had any kind of a functional formula, that would not be an issue. If there are coefficients in a function and the coefficients are themselves subject to regulatory review, you will not have any problem with the utility commission with regard to a revenue guarantee. One of the problems that will exist in satisfying both the legal and conceptual questions, is that once you go beyond lambda's in building a formula you are going to have to derive a set of operating coefficients. The system lambda's do lend themselves to this pricing concept.

There is a need at this point to discuss the impact of a spot pricing system on regulatory lags. A system like this would eliminate the bad regulatory lags. Regulatory lag as a spur to efficiency is highly desirable, and it is virtually the only spur that the system has to inspire efficiency on the part of the company. You do not want regulatory lag with regard to providing pricing signals that reflect changing conditions. There a lag is unproductive because it does not serve you well. This proposal is virtuous in preserving the correct lags and getting rid of the bad ones.

There is also the opposite extreme of the revenue requirement issue and that is the uncertainty or instability issue. In one sense, the proposed system is the same as any change in the pricing structure. It creates uncertainty as to what the revenues will be. That occurs when the change is in the level of prices as well as structure. It is possible that systematic risk of the utility will increase. Here, the record is clear and as was suggested, you do not know whether in point of fact the income effect will be one of smoothing or of increasing the oscillations of a system like this. It depends on a great many things.

My first question, can this be instituted within the existing regulatory framework, I think it can, no problem with fair and reasonable rates and problems with revenue requirements, can be resolved.

My second question: Will PURPA help? I think the answer to that, too, is yes. It will provide a forum for the next few years, it will be a forum for discussing a concept such as Homeostatic Control because the commissions across the country are going to be forced to consider the rate standards listed. It will also help in the sense that PURPA will require data and the data that will be filed, there are data that are explicitly being filed to help intervenors, these will help anybody who is external to the system to try to work with it. And finally PURPA will help in that it provides a problem--cogeneration--to which this suggested methodology seems to be well suited. As a result PURPA should help move this idea forward in at least three ways, but it is very important to recognize, as we in New York feel, that PURPA is primarily procedural and not substantive. The PUC's are not required to institute rates under PURPA; they need only examine their appropriateness. While you have a forum and you have the data and you have the problem, you do not have the force behind you to assure that rates of this type or those similar will be introduced.

The third question: are regulators and executives able and willing to be involved in a change of this sort? My answer would be yes to that, too, but I would not suggest that they would be enthusiastic. The views on the responsiveness of the commissions and the executives differ substantially at this conference: some more positive than others. One is frequently somewhat amazed that the state regulatory system and the utilities have been as responsive to changes in pricing structure, or changes in methodology of pricing as they have been in the past 7 or 8 years. These responses can be seen benefiting many areas, and many jursidictions besides those discussed like New York, California, and Wisconsin. The system has also been responsive in many of the PUC's which have so far been silent. Make no mistake, there are problems in the system's responding. Two problems were mentioned in the discussion: one is the distribution problem across classes of customers and individual customers and the other is the problem of revenue requirements for the utility. Changing the distribution of the burdens across customers is very difficult. There will be a contest for any change in methodology, however appropriate, that involves changing the customer class distribution. It will be necessary to be very conscientious to try to work out a scheme whereby one institutes spot prices and at the same time does not disturb the distribution between customer classes. The companies are very jealous of their revenue requirements and their predictability. Any time you offer any kind of a change that puts that in jeopardy, you have a problem and it will be necessary to answer these issues satisfactorily in order to win their support.

The last question posed was: How do you do it? How do you get a Homeostatic Control system started? I would echo the comments of the last speaker, find a special contract. Get a simple, specific rate; get a way to put the technology in place; get a customer and a utility, both of whom can agree that there's something in this concept. If you can do that, exactly as was said before, the problem of distribution does not exist, the problem of revenue requirement does not exist, the utility has accepted it; and the Public Utility Commission simply has to check on one thing: Is anybody else damaged? If no one else appears to be damaged, and that's relatively easy thing to do, at least in the inception of the contract, then you can make a concept like this work. Do not study this concept to death; they are clear. You have a philosophic base; there is a technology that is understood in putting this into practice. Get started. Put it into operation. And I think there are many specific places to do exactly that.

One other point needs to be added in getting this concept moving forward; it is not necessary to push Homeostatic Control as a substitute for time-of-day pricing schemes; it is a complement to it. It will salvage some of the benefits that time-of-day can not. To the extent that it can be presented as a compliment to PUC commissions, it will be a benefit. If you're an academic, you want to present your ideas as being distinct, different, and totally ahead of anybody else's. You want to differentiate yourself to a maximum degree possible. If you're dealing with a commission the one thing you want to say repeatedly is, nothing is new, this is just what they've been doing forever, just a little change.

6.4 System Control and Quality of Supply*

There are two principal issues associated with quality of supply, continuity and constancy. Continuity deals with the idea that when the customer flips the light switch, the light goes on. Constancy relates to the fact that the frequency of the system hovers around 60 hertz, drifting by less than 1%. If it drifts too far from this level specific users such as the television networks become disturbed and others who count on the timing nature of the system also are affected. Few customers realize the full extent of the damage caused by a deviation from the standard system frequency given that their primary concern is continuity rather than constancy. For those for whom constancy is a requirement they are willing to pay a high price for that characteristic while we know that for others even continuity is not a requirement as individuals and firms opt for contracts that allow the utility to interrupt their power flow. The analysis of the overall value and cost of a device such as a FAPER must be weighed against the cost to the system of having specific deviations in frequency. It is necessary to evaluate whether there would be more or less variation and whether this has a value (or a cost) to those customers who are buying constancy over continuity.

An example that might prove useful for consideration in analyzing an additional potential for Homeostatic Control would be a system in which

*Summarized by Paul Dandeno.

there is at present a 5000 megawatt load, and 20% reserve margin given 6000 megawatts of installed capacity. Give a 2 to 4% annual growth rate without a plan for capacity expansion, the questions of continuity and constancy become extremely significant to the customer. The Homeostatic Control could eliminate some of the problems that would be encountered by this example.

The concept of the FAPER and VAPER should be considered seriously given our historical experience with both distribution and transmission systems and the manner in which these affect the customer. The FAPER and VAPER may be of additional use both in increasing the reliability of the system with regard to area control, the power flowing across tie-lines, and with regard to overall system operations working in conjunction with automatic generation control devices.

Returning to the question of response of consumers, the quality of supply concept allows customers to respond to what they believe that it is worth for them to have power for any specific need such as air conditioning or the operation of a specific process within a plant. This essentially allows the customer to make a choice between air conditioning which, it might be argued, they would choose to turn down and lights which they would, in all likelihood not choose to be without. In the past our only means of dealing with times at which the system was near its true capacity was to go on radio and television and request conservation on the part of industry and the public. The general feeling today is that this would not be as effective as it was 8 or 9 years ago. The homeostatic control concepts would replace this type of appeal to the public while allowing for actions on the part of specific consumers to reduce their consumption in response to overall system quality.

Appendix A

GLOSSARY OF TERMS: ELECTRIC POWER SYSTEMS

Many terms have different meanings depending on who uses them and in what context. This can cause communication problems especially when individuals of different backgrounds are discussing topics which cover a wide range of interests. The following list provides a set of definitions related to electric power systems. Many are vague, arbitrary, or compromise definitions. However, they are self-consistent and provide a framework for discussion.

The following definitions apply to electric power systems:

- Electric Power System: Utility generation, transmission, and distribution. Customer load and possibly generation.

Basic physical quantities are:

- Power: Instantaneous power. Measured in kilowatts (KW) or megawatts (MW).
- Energy: Integral of power over time. Measured in kilowatt hours (KWH) or megawatt hours (MWH).
- Frequency: Frequency of AC voltage and current in region of concern, nominally close to 60 Hertz (Hz).
- Voltage: Magnitude of AC voltage (volts).

The definitions are grouped into the following general categories

1. Costs
2. Pricing
3. Rates
4. Regulation
5. Generation

6. Transmission Distribution
7. Load
8. Elasticity
9. Load Management
10. Vulnerability/Reliability/Security
11. Reserves
12. Control
13. Scheduling
14. Planning
15. Homeostatic Control.

1. Costs

Cost refers to the dollars needed to provide electric power to the customer usage devices. Other types of costs such as land use or pollution are not discussed here except as they are reflected into dollars expended for control (e.g., scrubbers).

- Fuel Cost: Cost of fuel used to generate electricity
- Capacity Cost: Cost of generation, transmission, distribution, etc.
- Operating and Maintenance Cost: Cost of operating and maintaining power plants, transmission systems, etc.
- Cost of Capital: Cost of raising money through bonds or stocks to build, operate, and maintain power system.
- Time Averaged Cost: Total expenditures over a time interval divided by time interval's length.
- Plant Averaged Cost: Costs averaged over units such as power plants.

- Incremental Cost: Cost of the next increment of power; not associated with any particular pricing philosophy.
- System Lambda ( ): Incremental fuel costs for the utility per unit of power delivered to the load centers. Recomputed every 5 minutes by Economic Dispatch.
- Embedded Capital Cost: A philosophy of costing capital based on the principle that the utility should recover the actual money invested in capital equipment plus a reasonable rate of return.
- Marginal Capital Cost: A philosophy of capital costing which says that the capital costs are based on the replacement cost rather than the embedded cost.
- Marginal Fuel Cost: A philosophy of costing fuel based on "replacement cost" of fuel rather than purchase price.

2. <u>Pricing</u>

A pricing philosophy determines the basic principles on which rates are established.

- Embedded Cost Pricing: A pricing philosophy based on embedded costing principles for determining cost of capital and annual average costs of fuel and operation and maintenance.
- Marginal Cost Pricing: A pricing philosophy based on marginal capital and marginal fuel costing principles.

3. <u>Rates</u>

Rate making methods established by regulatory commissions using various pricing philosophies determine the pricing structure under which customers pay the utility for electric power (or vice versa).

- Declining Block Rates: Charges per KWH decrease with total energy consumption.
- Demand Charge: Charge related to the electricity demand of a customer during a particular period. Usually related to the customer's peak electricity demand; often modified by effect of a ratchet clause.
- Energy Charge: Charge related to the energy a customer uses during a particular period.
- Connect Charge: Fixed charge for being connected to distribution system.
- Power Factor Charge" Charge related to the amount of power the utility is willing to furnish as backup; often independent of whether or not it is used.
- Time of Use (TOU) Rates: Rates whereby the demand and energy charges vary depending on the time of day, day of week, and season of year in a prespecified, published rate schedule.
- Interruptible Rates: Special rates for customers who give the utility direct control of their load under prespecified situations and conditions.
- Buy-Back Rates: Rate at which utility buys power from customer generation.

4. <u>Regulation</u>

- Rate Base Regulation: Most commonly used method of determining the maximum number of dollars a utility is allowed to collect from its customers. Under rate base regulation, annual allowed revenues are equal to a rate of return on the company;s test year rate base, plus a one-for-one compensation for the company's test year operating expenses.

- Rate Base: Net utility plant in service, plus or minus other adjustments, i.e., capitalized expenses.
- Net Utility Plant: Original cost of a utility's generating transmission and distribution equipment minus accumulated depreciation.
- Capitalize: To finance an expense and amortize it over its useful life, generally using a combination of long-term debt and equity financing.
- Test Year: Time period chosen by a utility and/or a regulatory agency on which operating expenses, rate base, and revenue requirement are based.
- Revenue Requirement: Utility's allowed revenues, as determined by the regulatory agency.
- Operating Expenses: Uncapitalized day-to-day business expenses of a utility (e.g., O&M, depreciation, taxes).
- Allowed Rate of Return: Maximum return on rate base to a utility permitted by a regulatory agency. Generally a composite of the company's cost of capital (debt and equity), as claculated by the regulatory agency.
- Earned Rate of Return: Actual return earned by a utility in a given period.
- Historic Test Year: Test year based on a past period's financial figures.
- Future Test Year: Test year based on a projected period's financial figures.

- Regulatory Lag: Time delay between test year and when rates are altered to reflect cost changes.

5. <u>Generation</u>

A generating plant converts oil, gas, nuclear power, water, wind, sun, tides, etc. into electricity.

- Utility Generation: All generating plants owned and operated by the utility.
- Customer Generation: Any generating plant owned and operated by a customer.
- Name Plate Rating: Normal maximum power output of plant (emergency rating may be higher).
- Firm Capacity: The power output level that a generator can be reasonably expected to produce under normal operating conditions over a specified period of time.
- Capacity Credit: Amount of firm capacity a plant such as hydro, solar, and wind can be assigned.
- Installed Capacity: Sum of all installed utility generation. Can vary widely depending on whether name plate or firm capacity values are used.

6. <u>Transmission Distribution</u> (T-D)

The transmission and distribution network provides the electrical links that enable power transfers between generation and loads.

- Transmission Network: High-voltage network (138 kV and above) used to interconnect utility generators and load centers.
- Distribution Network: Low-voltage network which distributes power taken from transmission network to customers.

- Voltage Profile: Magnitude of voltage at different points (busses) in the network.
- Waveform Quality: Measure of the amount of distortion introduced into the network by generators or loads.

7. Load

Load is a general term covering many aspects of the demand for electric power and energy.

- Demand for Electricity: Customer's desire for services (lights, heat, etc.) which can be fulfilled by use of electric power.
- Electricity Demand: Integral of power used by customers over a time interval divided by the length of the time interval: i.e., average power. Typical time interval 15 minutes to 1 hour (MW).
- Interruptible Load: Electricity demand which the utility can directly turn off or on depending on the utility's needs, time of day, etc. Prior arrangements made between customers and utilities.
- Skyline Curve: Plot of electrical demand versus time.
- Load Duration Curve: "Time collapsed" skyline curve giving the percentage of the the electricity demand is at a particular level.
- Load Factor: Measure of peak to total energy for a specified time interval.
- Load Model: A mathematical structure and associated parameter values which can be used to determine how the demand will

behave in the future depending on hypothesized inputs on weather, prices, etc.

- Load Forecast: A particular forecast of future demand for specified weather and price scenarios.

8. <u>Elasticity</u>

Elasticity is a concept devised to indicate the degree of responsiveness of quality (Q) demanded to changes in the market price (P). It depends primarily upon <u>percentage</u> changes and is independent of the units used to measure Q and P." (<u>Samuelson Economics</u>)

- Instantaneous Elasticity: Elasticity of a consumer to price changes in short time periods such as implied in homeostatic spot pricing intervals (periods of minutes or hours).
- Short-term Elasticity: Response of consumers to changes in price for electricity in time periods in which the capital stock of the consumer is fixed (periods of less than 1 year).
- Long-term Elasticity: Responses of consumers to changes in price for electricity in time periods in which the capital stocks may be modified (periods greater than 1 year).
- Long-term Equilibrium: State of balance between supply and demand which occurs when the capital stocks have adjusted on both the supply and the demand side.
- Energy Elastic Demand: Demand which is sensitive to price, but which will tend not to be rescheduled to a later time.
- Power Elastic Demand: Demand which is sensitive to price, but which is energy inelastic so that the power not used at a given time due to a price will tend to be rescheduled at a later time.

9. Load Management

Load Management is a term referring to the wide variety of techniques being proposed today to change the timing and magnitude of the demand for power so as to match better the costs of providing power. No single consensus on the scope of the term load management has evolved. The term is used in many ways in many different contexts. It is often applied to time-of-use pricing and direct utility control of customer electricity use. In some contexts it is applied to cogeneration, providing economic incentives to install storage, solar, etc.

10. Vulnerability/Reliability/Security

Various terms are used to refer to different aspects of an electric power system's ability to supply enough electric power energy to meet the demand for electricity.

- o Vulnerability: Power system's ability to control/reduce social economic impacts resulting from major disrupting effects such as oil embargos, coal strikes, or nuclear plant curtailment.
- o Reliability: Ability of a planned power system to supply customer demand taking into account probabilities of demand variation and forced outages. "Loss of load probability" is commonly used as a measure of reliability in generation expansion planning. Reliability increases as operating reserve increases.
- o Security: Ability of an existing power system to supply customer demand taking into account existing generation, transmission and distribution contingencies.

11. Reserves

The reliability/security of a power system is dependent on the generation reserves available.

- Spinning Reserve: Amount of extra capacity on power plants already in operation that is available within 5 to 10 minutes to meet unexpected plant outages or loss of tie-line support.
- Fast Start Reserve: Reserve such as gas turbines which can be operational in the 5- to 20-minute time span.
- Operating Reserve: Difference between the installed capacity available for a time period and the peak demand expected during that time period.
- Planned Operating Reserve: Operating reserve associated with system expansion plans.

12. Control

Power system control refers to the control of power system dynamics--swings in the time range of 0 to 10 minutes.

- System Inertia: Total physical inertia associated with the generators in the region of concern.
- System Damping: Natural damping of the system transient response due to changes in frequency.
- Boiler Turbine Dynamics: Response characteristic of the various steam boilers and steam, gas, hydro turbines in the region of concern.
- Governor Action: Effect of individual governors on power plants to vary boiler turbine outputs to maintain frequency within a desired range.

- Tie-Line Support: Effect of power transfers to and from the interconnected system outside the region of concern over the tie lines.
- AGC: Automatic Generation Control (AGC) is a centralized control system which sends correction signals to various power plants every few seconds to maintain system frequency and tie-line schedules close to their desired levels.
- Voltage Control: Control of voltage magnitudes of different nodes (busses).
- Load Shedding Under Frequency Relays: An automatic method of dropping load when frequency well below 60 Hz indicates an unacceptable input-output power balance on the system.

13. <u>Scheduling</u>

Power system scheduling refers to the scheduling of generators, storage, TD, and usage in the time range of 5 minutes to one year. The functional facilities are assumed to be fixed.

- Economic Dispatch: Computation of the optimum generation schedule of committed plants to minimize fuel costs taking into consideration transmission losses. Computation typically repeated every 5 minutes.
- Unit Commitment: Determination of the optimum commitment (scheduling) of plants hour by hour for the next week. Based on forecasted demands, plant capabilities, fuel cost, storage capabilities, etc. Repeated once a day or more often when unexpected events occur.

- o Maintenance Scheduling: Determination of optimum plant maintenance and nuclear refueling schedules week by week for the next year. Done seasonally or more often when unexpected outages occur.
- o Security Assessment: Determination of whether the power system can be expected to survive events; generally associated with a list of phyothesized contingents. Provides constraints to economic dispatch, unit commitment, and maintenance scheduling.
- o Load Shedding via Voltage Reduction: Attempt to reduce electric demand to be met by utility generation by reducing magnitude of voltage at which power is provided to customers.

14. Planning

Power system planning refers to the determination of facility additions and modifications in the time range of 1 to 40 years.

- o Generation Expansion Planning: Planning new generation facilities
- o Transmission Distribution Planning: Planning new TD facilities.

15. Homeostatic Control

Homeostatic control is an especially coined phrase which refers to a new philosophy for control, scheduling, operation, and pricing for electric power systems.

- o Energy Marketplace: A concept of time-varying prices for electricity where prices depend on "instantneous" supply-demand relationships/costs.
- o Marketing System: Portion of utility that enables Energy Marketplace to function. Consists of T and D system and necessary computation, communicaton, and control systems.

- Spot Price Buy: Price at which the customer can buy power from Marketing System.
- Spot Price Buy-Back: Price at which Marketing System is willing to buy power from the customer.
- Spot Price Interruptible: Discount price at which the customer can buy power from Marketing System with understanding power can be interrupted if needed.
- Spot Pricing Philosophy: Spot prices are obtained primarily using economic principles such as embedded cost pricing or marginal cost pricing. When power system is approaching capacity limits (generation and/or TD), Operational Needs Pricing principles affect spot prices.
- Operational Needs Pricing: A procedure whereby economically based spot price is modified depending on the operational needs of the electric power system.
- Power Type Dmeand: Demand coming from usage devices which need power at a specific time. Examples include lights, computers, TV and many motors.
- Energy Type Demand: Demand coming from usage devices which must be maintained in an average condition. Such devices are indifferent as to the exact time at which the energy is furnished. Examples include heating and cooling.
- Frequency Adaptive Power Energy Rescheduler (FAPER): A local control device installed on customers' energy type usage device to help control the system frequency-power balance. Does not interfere with customer needs. Uses only locally

available frequency measurements and is not under direct utility control.

- Building Data Link (BDL): Digital data communications medium located within the boundaries of individual customer environment to interconnect DRIDM, ERAC, and customer power consumption devices and monitors.
- Energy Resource Allocation Controller (ERAC): Dedicated microprocessor-based computer, belonging to the customer and connected to BDL to control switchable power consumption devices according to pricing information and customer defined priority.
- Dynamic Rate Integrating Demand Monitor (DRIDM): Microprocessor-based customer energy usage monitor intended to replace present electromechanical watt-hour meters. It records customer charge in accordance with a time-varying rate structure and performs interfacing and protocol support functions between the MCCL and the BDL.
- Marketing Interface to Customer (MIC): Includes the utility company data source, the MCCL, and the DRIDM to provide the customer with information pertaining to distribution system status and instantaneous pricing.
- Marketing Interface to Customer Communications Link (MCCL): Communications medium, protocol, and syntax used to transfer data between the power company and the customer.
- Distributed Shedding: A load shedding structure characterized by the location of breaker relays at the customer end of the

transmission network instead of at intermediate nodes. Breakers are activated by DRIDM in accordance with instructions received via MCCL.

- Microshedding: Microprocessor-based distributed computer network capable of controlling customer devices in a load shedding situation.

APPENDIX B:

INDUSTRIAL COGENERATION AND HOMEOSTATIC CONTROL

This appendix provides background information on the potential impact of homeostatic control upon industrial cogeneration. Issues explored in this material are:

- o What are the opportunities and problems posed by industrial cogeneration and its interaction with the power system?
- o How effectively can the current approaches for exploiting the advantages and alleviating the problems of cogeneration achieve their goals?
- o Does Homeostatic Control improve upon the current approaches?
- o How soon could it be feasible to implement it?

The following material is provided as an example of Homeostatic Control's effect on this combined conservation and generation technology, one which has raised many issues related to the operation of and rate making for electric power systems. This appendix is divided into three sections:

B.1 Cogeneration: An Introduction

B.2 Rates for Industrial Cogenerators

B.3 Homeostatic Control and Cogeneration

The introduction (B.1) briefly defines cogeneration and discusses ownership and control options. "Rates ..." (B.2) surveys the types of pricing structures being designed for industrial firms that are involved with different cogeneration ownership and control arrangements. "Homeostatic Control and Cogeneration" (B.3) speculates on the problems that Homeostatic Control can and cannot alleviate.

B.1 COGENERATION: AN INTRODUCTION

For the purposes of the discussion here, industrial cogeneration means the simultaneous production of:

1. electricity and
2. steam or heat for industrial process needs.

Cogeneration considerably improves upon the energy efficiencies attainable in the separated generation of electricity and process steam or heat. The key operating and design difficulty involves balancing process heat needs with electrical needs. Unless the cogeneration plant is linked with the power system, extra generation capacity must usually added at the site to ensure electricity supply reliability for the electrically isolated plant.

The amount of electric energy supplied by cogeneration has increased fourfold since the 1930's. Its share of total U.S. electricity supply, however, has diminished from 18% in 1941 to 4.3% in 1975. This decline has been attributed to both institutional factors and the changes in energy prices and technologies during the 1950's and 1960's [1]. Since energy prices have now risen sharply and since industrial steam and heat used 28% of the U.S. fuel consumption in 1968 while electricity generation consumed 21%, numerous studies have concluded that cogeneration is "an energy technology whose time has returned" [1, 2, 3, 4, 5 and 6].

A variety of ownership and management alternatives exist for cogeneration facilities. For the purposes of the discussion here, the key organizational classes are limited to cogeneration units producing steam for industrial processes and operating in parallel with the power system:

1. Customer owned and controlled cogeneration with no excess power: the cogeneration plant electrical output does not exceed the customer's internal electricity usage, thus a net flow of power from the customer to the power system rarely occurs.

2. Customer owned and controlled cogeneration with excess power: the cogeneration plant's electrical output usually exceeds the customer's internal consumption, so a sale of electricity to the power system is desirable under a buy-back arrangement.

3. Shared cogeneration plant ownership and operation: under a variety of plant ownership and control alternatives, the customer and the utility share the plant's output along with its operating and capital costs while the utility usually assumes responsibility for the economic dispatching of the facility (when the plant is not operating, the industrial steam needs are met from a back-up boiler).

4. Utility owned with steam sales: the utility owns and economically dispatches the cogeneration plant with the steam sales to the industry taking place at negotiated rates.

For simiplicity, this background paper will concentrate on classes 1, 2, and 4.

Two themes underlie many of the approaches for these institutional arrangements and their associated steam and power rate structures. First, the cogeneration plants should be encouraged to run as if they were economically dispatched by the power system operators whether or not they are directly controlled in this way. Second, the rates paid or received by the industrial cogenerator should reflect the unit's effect upon the power system's costs of service. The interconnection of a cogeneration plant should impose no burden on the utility's other customers. Likewise, the cogenerators should be fairly compensated for any special benefits that their electricity production confers upon the power system. A number of studies have noted the importance of utility rates in the economics of cogeneration [3, 4, 5, and 6].

B.2 EXISTING OR CURRENTLY PLANNED RATES FOR INDUSTRIAL COGENERATORS

The dual goals of economic operating incentives and cost-of-service pricing are embodied in the types of rates that a cogenerator faces. These rates are billed on a monthly basis and are fixed in advance, often under a long-term contract between the customer and the utility. The exact menu of rates depends upon the cogenerator's class.

Class 1 cogenerators, who have no net flows to the power system, first face an industrial tariff for their electric energy consumption during the billing period plus a demand charge for their peak usage. Since the cogeneration plant is inside the industrial firm's premises, the energy and demand viewed by the utility is after the cogeneration unit's contribution. Second, the firm will pay a stand-by charge for the opportunity to receive additional power if the cogeneration unit fails or is undergoing maintenance; the firm's purchases reflect all its usage if the cogeneration unit is not operating. Depending on the particular utility, the energy and demand charges may be different than the tariff for non-cogenerating customers.

Class 2 cogenerators, who have planned electricity flows into the power system, face the energy and demand components of the industrial tariff for any electricity purchases that they have made in excess of their cogeneration or when the unit was not operating. For their sales to the power system , they will receive payment according to the electric energy buy-back rates and capacity credits if the energy was delivered within the terms of a contract fixing a minimum operating schedule and reliability. Finally, the firm pays a stand-by charge for the opportunity to receive power if the cogeneration unit fails or is undergoing scheduled maintenance.

Class 4 customers, who buy both steam and power from the utility, pay standard <u>industrial tariffs</u> for their electricity and, usually, an individually negotiated <u>steam tariff</u> for their steam purchases from the cogeneration facility. The utility receives all the cogeneration unit's electrical output directly. The individual contract between the parties must set whether or not the utility provides the industrial firm with steam during periods when the cogeneration unit is not producing electricity for economic reasons or because of maintenance or unanticipated outages. The fundemental issue associated with setting steam tariffs is the rate of return on revenues associated with the utility-owned cogeneration unit: should they be allowed a rate higher than the regular regulated rate of return for a cogeneration unit because of higher systematic risks associated with the steam revenues from this single industrial customer?

The electric industrial purchase tariffs, stand-by charges, buy-back rates, capacity credits, and steam tariffs may include clauses for seasonal, weekly, and daily time-of-use components and utility fuel cost adjustments. Although the multitude of rates for cogenerators contain numerous provisions for encouraging plant operations and compensation in accordance with power system conditions and costs of service, they do not reflect the power system or cogeneration unit conditions as they actually develop because the rates reflect the <u>expected</u> rather than the <u>realized</u> conditions. For example, stand-by charges are intended to pay for the additional capacity that the utility must provide to serve the Class 1 or 2 customer when its plant is out of service; unless the industrial firm's plant outage occurs during power system peak conditions, the industrial firm has only the miniscule impact associated with the operation of the next generation increment in the power system's economic dispatch order. The stand-by charge is usually designed to reflect the probability of the simultaneous occurence of the system peak and a cogeneration unit outage combined with the cost effect of this event--but these costs do not really occur unless the cogenerator's outage happens at the peak time. Unless the stand-by charge accurately reflects expected costs, the charge forces the industrial firm to add back-up generation to avoid the charges; this service could usually be more economically accomplished by the power system with its greater diversity of generation and electric loads. Energy buy-back rates reflect the average value of the cogenerator's energy sales to the power system assuming typical load conditions and performance by the other generation units--if the load at a specific time is unexpectedly low, it would be better if the cogeneration plant was not operating because the utility is paying more for its production than it would have to pay for electric energy from other units. No Class 1 or 2 cogenerator has any incentive to participate in power system frequency or quality of supply control.

B.3 HOMEOSTATIC CONTROL AND COGENERATION

The information transfers imbedded in homeostatic control clearly demonstrate their value in the incentives they offer to cogenerators. The spot buy and buy-back prices can reflect system conditions very closely, thus providing contemporaneous incentives for cogeneration unit operation and just and reasonable payments reflecting current costs of service. Actions of devices like the FAPER can provide means for the customer as well as the utility to participate in actions to maitain stable system frequency and quality of supply. The cost of spot price communication and metering to serve the MIC function is small compared to the advantages offered at even the present time.

Impact of the Energy Marketplace

With spot pricing for energy purchases and buy-back, the mire of special rates and conditions for cogenerators disappears. Every industrial customer operating its own cogeneration unit (Class 1 and 2) faces the current spot buy price when its usage is more than the unit output and the current buy-back spot price when the unit output exceeds usage. Since the buy-back price reflects the power system's needs for additional generation on a five minute basis, the industrial firm then has the same economic generation incentive as if it were directly controlled by the utility's economic dispatching. Since the spot buy and buy-back prices can be designed to reflect the chosen definitions of "cost of service," the industrial firm pays or receives payment directly according to its impact on current system costs. This approach, as noted in section 4.4.3, is in direct consonance with the Public Utility Regulatory Policies Act section 210, offering even more flexibility than was envisioned by Congress.

Take as a simple example a firm that uses no electricity but requires steam in its processing operations. It has built a cogeneration unit to provide its steam needs and sell all the electric energy output to the local utility. When the cogeneration plant is not operating, the plant can obtain steam from an oil-fired package boiler, which has a low capital cost but burns expensive low sulfur oil. Since the firm never uses electricity in excess of the cogeneration plant output, it always sells to the utility at the spot buy-back price. If the spot buy-back rate falls below a certain minimal value, $r_{bb,min}$ the firm can

FIGURE B.1

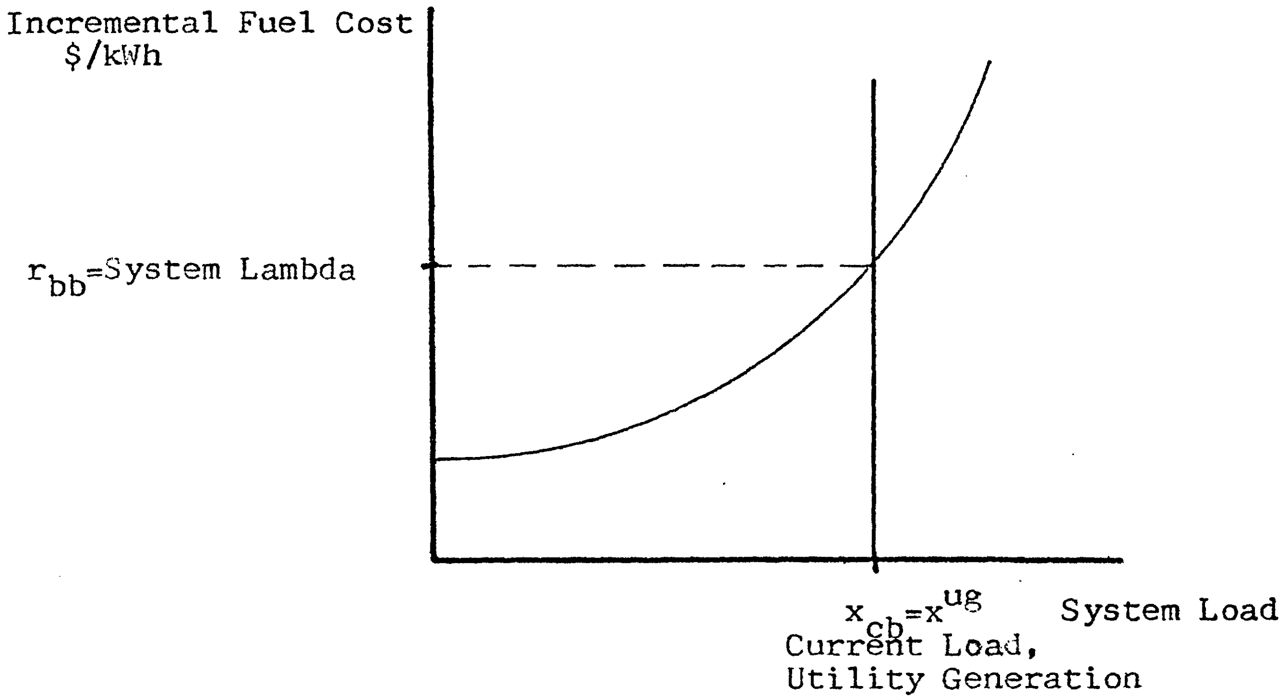
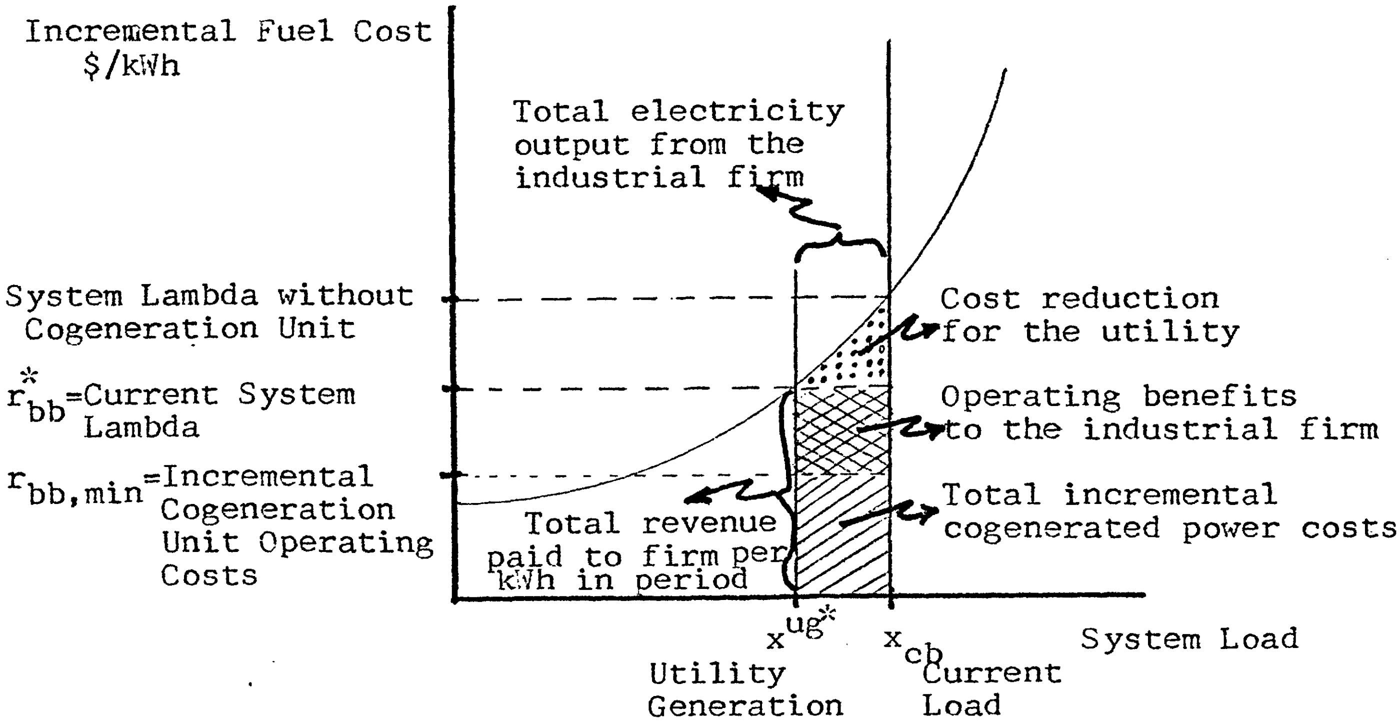


FIGURE B.2



(Energy buy-back spot price, r_{bb}, is set at System Lambda in the example shown here; System Lambda is the current incremental fuel cost for utility-owned generation plants) produce steam more cheaply from the package boiler. The "per unit excess of revenues less alternative costs" for the cogeneration unit is the difference between the current energy spot buy-back price and the minimum price for the economic operation of the cogeneration plant: this is the operating benefit to the industrial firm for the output of a given mix of steam and power from the cogeneration unit. Since the utility receives this energy and avoids placing more expensive sources of generation into service, it also receives a benefit in terms of a reduction in its operation and fuel expenses; this is directly passed on to the other consumers through reduced power system operating costs. Figure B.1 illustrates an incremental fuel cost curve for the utility at different load levels under an assumed utility generation unit availability; this is the type of information that would be available during the short spot pricing intervals but is not available when rate schedules are set far in advance. The vertical line, x_{cb} , represents the current system load assuming there are no sources of generation other than the utility's. Further assume that the utility sets the buy-back spot price at its Systems Lambda, r_{bb}, which is the current incremental fuel cost from its plants. Figure B.2 shows the conditions if the industrial cogeneration unit is producing an electrical output of ($x_{cb} - x^{ug^*}$). The System Lambda and utility generation are both reduced to r^*_{bb} and x^{ug^*}, respectively, resulting in the costs savings to the utility given by the dotted area. The utility's operating costs for serving the customers' loads are now the total utility generation fuel costs plus the revenue paid to the industrial cogenerator, which is shown in the single and double cross-hatched area. The industrial firm receives benefits (double cross-hatched area) above the direct incremental costs of running the unit (single cross-hatched area). The incremental operating costs for the cogeneration plant do not include any capital charges for the cogeneration plant because that is a "sunk cost"; this capital must be recovered out of the operating benefits--if the firm did not anticipate sufficient operating benefits over the life of the unit to recover these capital costs, the cogeneration unit should not have been built.

The above discussion has presumed that the cogeneration unit's output is all available at one incremental cost at a given steam consumption rate. Actual cogeneration plant designs embody more complicated operating economics: the incremental costs depend on both the steam and electric output. The industrial firm could further gain by scheduling its steam needs for when electric output from the unit could yield the maximum profits from the combined primary industrial product processing and the cogeneration electricity sales.

The situation becomes slightly more complicated for a firm using electricity in addition to steam. When the spot buy-back price is above the minimum to cover incremental cogeneration costs, the unit runs at full output. If the spot buy-back price drops below this minimum incremental cogeneration cost but the spot buy price is still above that cost, the unit should produce just enough power to cover the firm's internal electricity needs. When the spot buy price falls below the incremental cogeneration costs, the firm should fall back on the package boiler for steam and purchase electricity from the power system. The differential between the buy and buy-back spot prices introduces a small incentive problem since the cogenerating plant is operating at times when the power system can generate more cheaply but the customer sees its own generation as less expensive--this demonstrates the balance that must be struck between the problems of obtaining a good cost-of-service measure and the problem of incentives for globally economic efficient operation. Nevertheless, spot pricing clearly alleviates many of the difficulties with conventional approaches to rate-making for industrial cogenerators.

In cases where the utility owns the cogeneration unit (Class 4), the steam rates could be based on spot pricing just as the electricity rates. Because of the economies of joint production embodied in cogeneration, the steam rates would normally drop when the electrical output from the unit is most valuable, i.e. when the electric spot prices are highest. During low power system load conditions, when the cogeneration unit's electric output is unneeded, the steam spot price would rise to the cost of producing steam in the back-up boiler.

The costs of implementing homeostatic control for even a single cogenerator are small compared to the apparent benefits. The communication of the spot prices can be made on leased telephone lines. This information can be used by the process control operator through the energy control computers already installed in many industrial plants. The recording of electricity buy and buy-back flows can be made on the magnetic tape recorders already available for special time of use rates.

The industrial firm must endure larger short-term uncertainties in its buy and buy-back rates. On the other hand, the firm gains through its opportunities for more flexible operation to take advantage of profitable situations while simultaneously aiding power system operation. The regular fluctuations in the spot prices will be very predictable; any long-term shifts in the spot prices would have eventually been reflected in shifts in the existing classes of rates anyway.

Impact of FAPERs and Cogenerator Participation in System Control

The two most straight-forward opportunities for customer cogenerator participation in system control are governor actions by the cogeneration plant and FAPER actions on the customer's electrical loads. Governor actions or decentralized generation control to restore system frequency to the standard 60 Hz can increase the cogeneration unit's output when system frequency drops. Likewise, FAPER actions, on average, will reduce the firm's electric loads in such a situation. These two effects combine to increase the firm's net sales to the power system in response to system control needs based on frequency changes before any actions are taken for economic reasons at the subsequent spot price updates.

More subtle opportunities arise because of the economies of joint production in cogeneration. Electrical output from the cogeneration plant can be increased more economically when it is associated with an increase in useful steam output. This suggests that some steam uses in the industrial plant should be made sensitive to power system frequency so they <u>increase</u> during a <u>decrease</u> in frequency. This allows a more economical expansion in electrical output. This frequency adaptive <u>steam</u> energy rescheduling, however, does not involve loads with the diversity that FAPERs have within the whole power system, so investments for the economic short-term storage of steam energy (e.g.,steam accumulator tanks) may be needed to realize any advantages associated with the frequency-related control of steam load.

Concluding Comments

Homeostatic Control better meets the two cogeneration rate design themes better than existing or planned rate structures. First, the cogenerators, motivated by profit incentives, behave more nearly as if they were directly controlled by the power system economic dispatching. Second, they pay or receive compensation that is directly related to realized costs-of-service. They have to respond to current costs, not to costs that were anticipated but not realized or realized but not anticipated. Furthermore, industrial cogenerators would be forced to become more responsive to power system economics and control needs. Since the costs associated with implementing Homeostatic Control are only slightly higher than those for metering these customers under many of the other new rate structures, it presents an opportunity that should be taken advantage of in the near future.

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